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FOSSIL ENERGY

ASSISTANCE TO OIL AND GAS STATE AGENCIES AND INDUSTRY THROUGH CONTINUATION OF ENVIRONMENTAL AND PRODUCTION DATA MANAGEMENT AND A WATER REGULATORY INITIATIVE

Final Report
October 1, 1998-September 30, 2001

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Oklahoma City, Oklahoma

National Energy Technology Laboratory
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Assistance to Oil and Gas State Agencies and Industry through Continuation of Environmental and Production Data Management and a Water Regulatory Initiative

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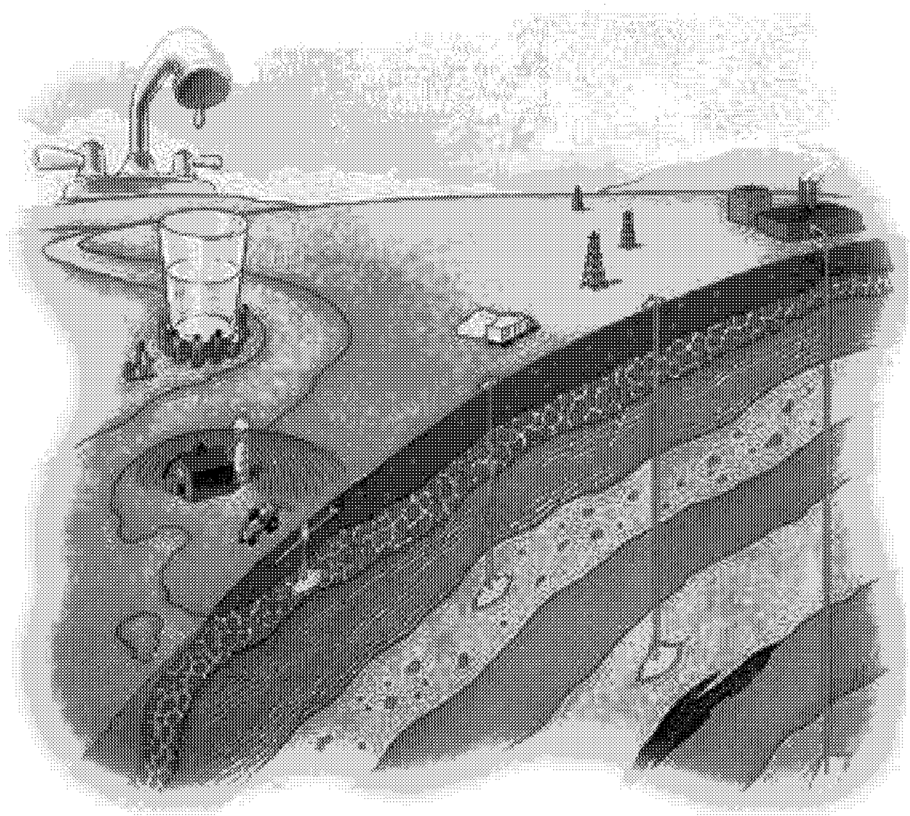
ASSISTANCE TO OIL AND GAS STATE AGENCIES AND INDUSTRY THROUGH CONTINUATION OF ENIVIRONMENTAL AND PRODUCTION DATA MANAGEMENT AND A WATER REGULATORY INITIATIVE

Featuring the Environmental Information Management Suite (EIMS), Risk Based Data Management System (RBDMS) and Cost Effective Regulatory Approach (CERA) Projects
1998-2001



A Nationwide Summary of Progress:

Database Solutions for Oil and Gas, Underground Injection Control, and Source Water Protection

Project completed by
The Ground Water Protection Research Foundation -
the research are of the Ground Water Protection Council

GROUND WATER PROTECTION
GWPRF
RESEARCH FOUNDATION

Grant Project Objectives:

This grant project is a major step toward completion of the Risk Based Data Management System (RBDMS) project. Additionally the project addresses the needs identified during the projects initial phases. By implementing this project, the following outcomes are sought:

- State regulatory agencies will implement more formalized environmental risk management practices as they pertain to the production of oil and gas, and injection via Class II wells.
- Enhancement of oil and gas production by implementing a management system supporting the saving of abandoned or idle wells located in areas with a relatively low environmental risk of endangering underground sources of drinking water (USDWs) in a particular state.
- Verification that protection of USDWs is adequate and additional restrictions of requirements are not necessary in areas with a relatively low environmental risk.
- Standardization of data and information maintained by state regulatory agencies and decrease the regulatory cost burden on producers operating in multiple states.
- Development of a system for electronic data transfer among operators and state regulatory agencies and reduction of overall operator reporting burdens.

Grant Project Tasks:

This three-year project is divided into the following tasks:

Task 1 Complete Development of the Risk Based Data Management System (RBDMS)

Task 2 Assist State Oil & Gas Agencies and the Oil & Gas Industry with RBDMS Implementation

Task 3 Assist the State Oil & Gas Agencies in Streamlining Water Protection Regulations and the Regulatory Interaction with Producing Companies

The Ground Water Protection Research Foundation (GWPRF) is the research arm of the Ground Water Protection Council (GWPC). Although this project is a product of the GWPRF, references made regarding the GWPC are intended to be synonymous with the GWPRF.

The following is the Final summary of work completed during three-year report period.

(*Tasks 1 & 2*): Risk Based Data Management System (RBDMS) and the Environmental Information Management Suite (EIMS)

System Development: Comprehensive Natural Resource Management Tools

Since 1992, GWPC and it's Foundation the Ground Water Protection Research Foundation (GWPRF) has been developing the Environmental Information Management Suite (EIMS) to improve regulatory decision-making. EIMS is GWPC's strategic approach to assist states and industry in managing natural resources. The EIMS program offers the flexible integration of highly customizable data management tools including its flagship application Risk Based Data Management System (RBDMS), a desktop geographic information system (GIS), Internet reporting, and more. EIMS has become the standard for data management in state oil and gas agencies, with most of the production states now using RBDMS or an EIMS utility.

Advanced data management techniques enable states to make better, more cost-effective regulatory decisions. RBDMS started with the idea of developing a system to assess environmental risks associated with oil and gas injection wells to efficiently allocate regulatory and industry resources (money, time, and people) to prevent pollution of underground sources of drinking water. Attributes of today's RBDMS include its continued usefulness in assessing and reducing risk to drinking water, its use of nonproprietary software, its capability to address legacy databases, and its adaptation to variations in state regulatory programs and oil and gas production accounting methods. States using RBDMS have collectively realized a cost savings of over $20 million with greater confidence of having made decisions that are economically and environmentally smarter. The GWPC team overseeing the development, enhancement, and use of RBDMS are the state regulatory officials themselves, those who use and must ensure the integrity of the data.

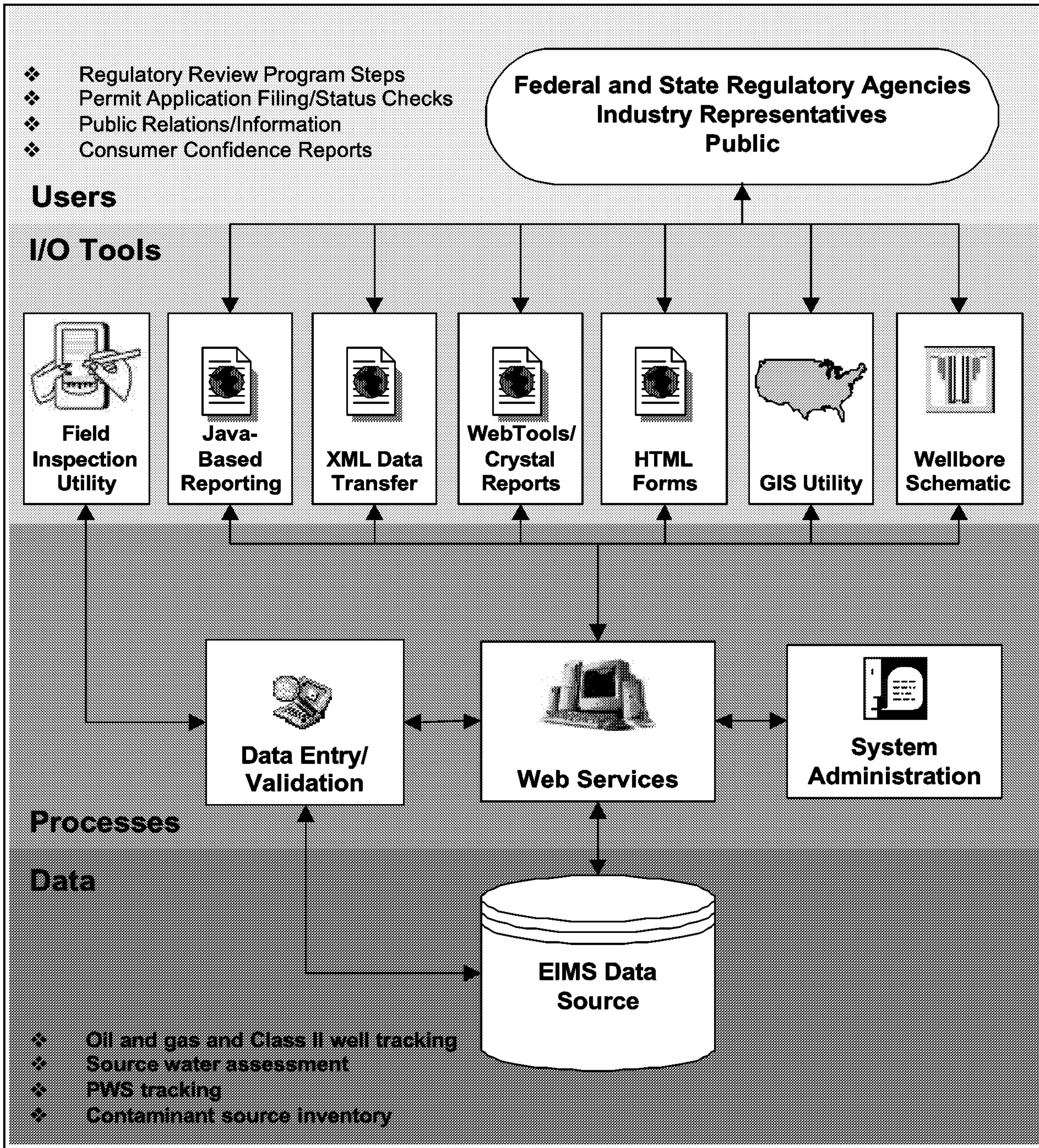
GWPC continues to take advantage of new technology to develop utilities that make EIMS more functional. For example, state regulatory agencies process hundreds of thousands of well permit applications for well drilling, re-working, and plugging and abandonment nationwide each year. An electronic permitting module now in development will increase efficiency and cost savings for both industry and states. The e.Permit program will speed the processing of permit applications and enable online approvals for routine activities such as re-working of oil and gas wells, significantly reducing operational downtime.

EIMS will integrate oil and gas resource data and state source water protection planning, a requirement of the Safe Drinking Water Act (SDWA) Amendments of 1996. This information will, in turn, assist public water suppliers and consumers in their water protection efforts. Because of this advanced data information system that links state energy resources and water quality planning, America's drinking water resources are safer.

Fitting the Components Together

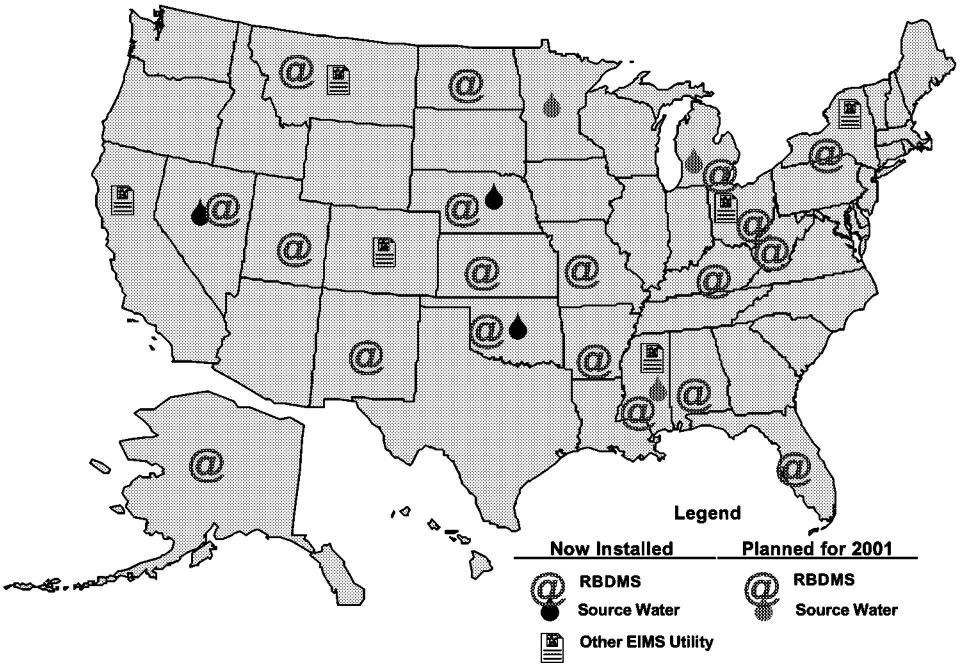
EIMS applications meet the comprehensive environmental data management and evaluation needs faced by federal and state regulatory agencies and industries tasked with natural resource development and public health oversight.

Tool	Key Uses
RBDMS Data Source:	➢ Track oil and gas well construction, operation, mechanical integrity testing, and production information. ➢ Assess current risk and forecast future risk posed by Class II injection wells. ➢ Manage the information state oil & gas regulatory programs need to collect. ➢ Accommodate users' operational needs through easy customization of the generic version.
Options for Internet Data Sharing:	➢ Display oil and gas well/source water information on state Web sites. ➢ Publish consumer confidence reports. ➢ Generate database reports through Crystal Reports. ➢ Use secured remote data entry via XML, Java applets, and HTML forms. ➢ Monitor system usage.
Field Inspection Module:	➢ Track Bradenhead inspections and five-year pressure tests. ➢ Perform source water assessments in the field. ➢ Work with GPS data. ➢ View and manage PWS information. ➢ Upload field-gathered data to the EIMS data source.
GIS Utility (Desktop and Internet):	➢ Integrate water quality and other environmental data (oil & gas) with state GIS base map coverages for spatial display and analysis of contaminant areal extent, nature, and source evaluations. ➢ Import and display source water delineations generated by modeling programs. ➢ Create data views to match specific evaluation purposes.
Wellbore Schematic Utility:	➢ Evaluate well construction details. ➢ Generate review documents for well plugging and abandonment. ➢ Prepare scaled drawings of wells. ➢ Perform volumetric cement calculations.
Economic Evaluation Package:	➢ Analyze production decline rates. ➢ Calculate oil and gas reserves. ➢ Do what-if assessments of production property present net worth.
SWAP Data Source:	➢ Provide central repository for the data collected for source water assessments and contaminant source inventories, including public water supplies (PWS) data and vulnerability determinations. ➢ Publish EPA source water and wellhead reports from database queries.



What is EIMS? *EIMS is a collection of data management tools used either singly or in any combination to meet specific state regulatory and resource protection goals.* The information that states and other users add to the data source will be freely sharable, and each tool is being designed to be expandable and reusable. Processes involved in maintaining and validating the data are transparent to the user, but critical in keeping the data source groomed for widespread sharing and accountability.

EIMS Participation Coast to Coast



Making a Difference in Resource Management…

Because of an advanced data information system linking state energy resources and water quality planning, America's drinking water resources are safer. Since 1992, the GWPC has been developing EIMS tools to improve regulatory decision-making. EIMS is GWPC's strategic approach to assist states and industry in managing information about oil and gas production wells, underground injection wells, source water, and watersheds. The results show that state agencies that use this tool have saved over $20 million for taxpayers. EIMS offers the flexible, integration of highly customizable data management tools including RBDMS, a desktop geographic information system, Internet reporting, and more.

With the addition of the Source Water database and assorted utilities to EIMS development, overall participation has continued to grow, as shown in this map. In 2000, four new installations of RBDMS were added: Alaska, Florida, North Dakota, and the Osage Nation in Oklahoma. Installations of both RBDMS and Source Water are continued to grow in 2001.

RBDMS and the Energy100 Awards - Improving the Quality of Life

RBDMS started with the idea of developing a system to assess environmental risks associated with oil and gas injection wells to efficiently allocate regulatory and industry resources (money, time, and people) to prevent pollution of underground sources of drinking water. Attributes of today's RBDMS include its continued usefulness in assessing and reducing risk to drinking water resources, its use of non-proprietary software, its capability to address legacy databases, and its adaptation to variations in State regulatory programs and oil and gas production accounting methods. The GWPC team overseeing the development, enhancement and day-to-day implementation of RBDMS consists of the state regulatory officials themselves, those who use and must ensure the integrity of the data. GWPC continues to take advantage of new technology and develop utilities that make RBDMS more functional. This system will allow integration between oil and gas resource data and state source water protection planning, a requirement of the Safe Drinking Water Act Amendments of 1996. This information will assist public water supplies and consumers in their water protection efforts.

Saving Money:
Advanced data management techniques enable states to make better, more cost-effective regulatory decisions. States using RBDMS have collectively realized a cost savings of over $20 million with greater confidence of having made decisions that are economically and environmentally smarter.

An electronic permitting module, currently under development, will deliver increased efficiency and cost savings for both industry and states. The e-permit module will speed the processing of permit applications and enable online approvals for routine activities such as the re-working of oil and gas wells, significantly reducing operational downtime. Each year, hundreds of thousands of well permit applications for well drilling, reworking, and plugging and abandonment are manually processed across the nation by state regulatory agencies.

GWPC is the proud recipient of a U.S. DOE "Energy100Award" for its Risk Based Data Management System (RBDMS). With this award, RBDMS is being honored as one of the 100 best scientific and technological accomplishments of the Department of Energy during the 20th century and an inspiring example of how public investment in innovation can make a difference in people's lives.

Other Noteworthy Results:
RBDMS is the only comprehensive, fully relational PC-based oil and gas regulatory data management system in the country. Originally designed to assist state regulatory agencies to manage oil and gas injection well data, RBDMS has been modified to include numerous enhancements, including modules for managing oil and gas production data and field inspection data. Twenty states are using RBDMS or one of the EIMS utilities. Some states are pursuing RBDMS modifications that will include data management for non-hazardous and industrial waste injection wells.

Industry Perspective: Letters and Comments
In New York…

NORNEW, INC.

Energy Development

April 3, 2000

Mr. Donald Drazan
New York State Department of Environmental Conservation
Division of Mineral Resources

I wanted to write and thank you for the opportunity to experiment with the Access Database for the 1999 Annual Well Report. It was very straight forward and easy to use. Most importantly, it made my job of preparing the report much easier. All the information necessary to complete the report could be put in as I received it from Houston and in the end it produced a well ordered, neat presentation. It was set up in such a way that I could also use it for my County, and Town Reports as well.

Throughout this year I will be able to update the information I need to complete the Report and next year should be able to finish it in a single afternoon by just double checking the information I have.

The programmers who are setting up the Database for you are doing an excellent job of making this an easy program to use. It will work well with people of various experience levels with the Access program. I would definitely say that the DEC is on the right track using Microsoft Access. It's an excellent program with very good import/export tools. As you know, I am already using it for other well drilling applications.

Please keep us updated on the changes that are being made. Thanks again, and keep up the good work! It makes everyone's life easier!

Cathy Ellis
Office Manager

In New Mexico…

New Mexico Oil & Gas Association

September 27, 2000

Ms. Lori Wrotenbery, Director
NM Oil Conservation Division

NMOGA would like to thank you and your staff for taking the time to present the NMOCD's Data Automation Plan 2000 to our Regulatory Practices Committee. It is a bold and ambitious undertaking, and we fully support your efforts in this regard. Migrating from manual electronic handling of data, matched with GIS capabilities and enhanced access for industry will benefit large and small operators in New Mexico in their search for new reserves and better operating efficiencies.

We particularly applaud your use of surveys to obtain feedback from stakeholders as this plan was being developed. Your proposed use of internet technologies to facilitate access will make these products available to the widest possible group of users in industry. As mentioned in our meeting, several large companies are prepared to assist the OCD in "cleaning up" the database by providing copies of internal electronic data.

As a future user of these tools, industry's input can be critical to insure a product that is valuable to all stakeholders. Your commitment to seeking our assistance is appreciated, and we look forward to participating in the design, testing and implementation of the various components of the plan.

Bob Gallagher
President

A Summary of Benefits to Oil and Gas Operators

- Improved industry access to oil and gas commission data gives exploration geologists the ability to develop prospects and to drill and operate their leases more efficiently. Research can be done remotely, without incurring travel costs.
- The use of RBDMS in multiple state oil and gas commissions is furthering the goal of uniform application and reporting requirements among states, thus decreasing costs to companies that operate across state boundaries.
- Shut-in and idle wells that cannot be economically worked in today's market and that pose a low risk of USDW contamination can be preserved as possible candidates for enhanced oil recovery projects. Through RBDMS tracking and evaluation of mechanical integrity, static fluid levels, and idle well reports, the future value of those wells can be preserved.
- The increase in the efficiency of oil and gas commission personnel reduces the amount of the production-based conservation tax paid by operators and producers, which funds the state oil and gas commission activities.
- The time required to process applications is decreased because oil and gas commission staff can research and process Applications for Permit to Drill, etc., much more quickly by avoiding the rework loops of manual data re-entry and form re-completion.
- The ability to evaluate environmental risk results in construction and testing requirements commensurate with the level of risk.
- The ability to focus attention and resources, both governmental and industry, on those wells that pose the greatest environmental risks enhances protection of the nation's ground water, a concern of all global citizens.

Return on Investment

How Much Has RBDMS Saved the States?

A study of savings from implementation of RBDMS is now under way nationwide. However, member states have, on many occasions, discussed the resource saving abilities of RBDMS on a project-by-project basis. Further, in Montana alone, approximately 20 cases of non-compliance that EPA had been unable to identify were found and resolved through RBDMS.

Cost Savings Category	OH Dept. Natural Resources	NE Oil & Gas Conservation Commission	MI Geological Survey Division
Avoidance of Y2K compliance programs for mainframe computers and legacy databases	$500,000/year	$500,000/year	$800,000/year
Elimination of computer maintenance and usage fees	$500,000/year	$7,000/year	$400,000/year
Reduction of labor for data entry, handling, manipulation, reporting, and paper file management	Incalculable	Incalculable	Incalculable
Avoidance of litigation	Priceless*	Priceless*	Priceless*

*Faster turnaround, improved responsiveness, identification and resolution of noncompliance instances, improved data quality, and greater protection of USDWs.

The GWPC estimates that states have saved approximately $20 million with RBDMS. For example, in the few areas shown in the table below with only three states reporting hard numbers and extrapolating these savings nationwide, cost avoidance has been significant, thanks to RBDMS's client/server platform and the abandonment of legacy systems.

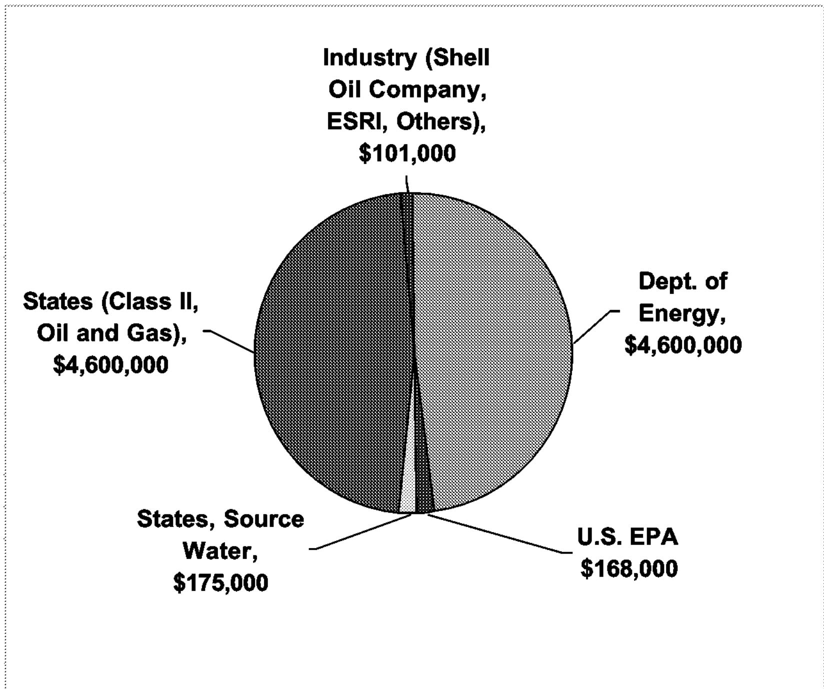
And Not Just the States…

Benefits also have been reported by industry. For example, in Michigan, Shell Western E&P, Inc. (SWEPI), began using a custom version of RBDMS to generate reports to EPA, analyze possible non-compliance issues, and evaluate well operations. SWEPI reports that RBDMS has saved considerable resources.

In Montana, the RBDMS program was instrumental in EPA granting the state regulatory authority over the Class II UIC program. The delegation of the program has positively affected all operators in the state, including Shell, Amoco, Exxon, Meridian, and others. Each has reported having realized substantial savings just in the first year of UIC program delegation to the state as a result of significantly faster turnarounds on permits, state responsiveness, and data availability. For more about benefits to industry.

Funding for EIMS

States continue to enthusiastically support EIMS in the form of hardware and software purchases, donation of staff time, and cash. In fact, states continue to match U.S. DOE funding. Over $9 million have been invested in EIMS/RBDMS development nationally, giving GWPC the ability to leverage these investments in a robust development environment. GWPC is now obtaining funding from the U.S. EPA to incorporate source water protection elements in the data management system.



EIMS APPLICATIONS

1. RBDMS

The Risk Based Data Management System (RBDMS) is a scalable client/server application that standardizes the data elements collected and stored by each state's oil and gas regulatory agency. GWPC has managed upgrades and enhancements to RBDMS each year since the early 1990s. Funding for this program development over the years has come from the Department of Energy and the many states that have embraced the technology. Summaries of this year's RBDMS utility development efforts follow.

Duplicate Handling System (DHS)

Also referred to as the Merge/Delete Utility, the DHS allows users to directly compare data to data records that reside in RBDMS. Data comparisons are shown in a side-by-side format. Users are allowed to choose which records and which data contained in each record should be maintained and which should be deleted from the database. The system provides quality control reports and incorporates a logical process for handling record comparisons and in addressing duplicates.

- Can be customized to fit each state's operational needs
- Provides the ability to manually select the specific well and location data to merge between records or other tables identified by the User
- Provides the ability to manually review the data to be merged from sub-tables
- Automatically merges and appends records between the two selected duplicate well records
- Generates a merge/delete statistics report on the process performed between two well records
- Provides the ability to delete a well record without performing any merge of data into another well record

Data Entry System (DES)

The DES consists of electronic forms that match the hard-copy formats used in state agencies to best facilitate rapid entry by data entry staff. Once data is entered, the database administrator can analyze data with an integrated data quality analysis tool that allows user-defined analysis specifications to be set with a graphical user interface. Data can be analyzed for required fields, one field can be compared to another, and the criteria each particular data record must meet can be specified. Once errors are addressed, the data can be re-analyzed.

A second quality check is made with the Data Flow Manager (DFM). This tool tests the data for compliance with the RBDMS data model and allows analysis of details such as whether each record has a valid operator or is in a valid county. The DES will then merge the entered records into the RBDMS structure using specific custom DFM interface records. Various options are provided in the DFM and DES to handle the output of records failing the merge process into RBDMS.

The DES was developed to allow customization to any ODBC-compliant database and is fully distributable. The DES also provides an archive of data entered to allow a historical summary of all records entered into the system via the DES. For more information.

Production Module

GWPC has upsized and expanded the RBDMS Production Module. The current production module is designed to provide the building blocks for state-customized systems. This basic production system tracks well detail information (including location), producing formation, pool/reservoir, and oil and gas field. The Production Module includes a lease/unit tracking system and production tracking by well and distinct formation. It also summarizes production data by lease/unit, tracks cumulative production data, provides graphical production analysis, and offers production data visualization reports.

Using the RBDMS basic production system requires that the data conform to the RBDMS generic data model (version 8.01). Production data must be submitted monthly by well and distinct production formation, with summary data (or disposition) tracked by lease (or unit). Production must be allocated to a single producing formation, which may be a single formation or combination of subsurface formations (or pools), and each well must be limited to a single owner/operator for tracking purposes.

GIS Capability within RBDMS

For RBDMS users, GWPC offers the ability to integrate the Sylvan Maps GIS control via ActiveX technology. The GIS control has been integrated with the Well Selection Criteria navigation form in RBDMS. Several state oil and gas agencies are now using this option.

Compare Database Utility

This EIMS utility compares a client's customized database to a "standard" database structure. The program produces a report of tables and fields that are present in the standard database and are missing or have been modified in the client version. Tables and fields added by the client are ignored. Databases such as SQL Server can be compared by first linking the tables to an Access mdb file with an ODBC connection.

2. Internet Reporting Options

Data reporting over the Internet has been one of the most exciting areas for EIMS development this year. GWPC has managed the development of several utilities designed to download information from existing state agency databases through queries with a variety of user interfaces over the Internet. Even more promising is the development of a Web application designed to give oil and gas operators access to ***upload*** data to state agency databases, specifically well permit applications and supporting documentation. Summaries of this year's development efforts follow.

e.Permit. Used for online well permitting, e.Permit access is protected by NT Server security, user names and passwords, and multiple tiers of immediate client-side and automatic server-side data integrity checks. Operators can upload permit applications to the database singly through menu-driven HTML forms or in batch through XML-formatted data transfers. GWPC also offers **e.PermitRemote**, an Access2000 application that will generate XML files for selected database record sets. The Wellbore Schematic

Utility is bundled with e.PermitRemote as a bonus feature. Users can check their permit review status through e.Permit's reporting features. Permits can be prepared as HTML reports, and special condition sets can be dynamically selected and sent as e-mail attachments.

Java-Based Reporting. Developed with Bulletproof's JDesignerPro software, the EIMS Java program allows dynamic data access via the Internet and can run as an application over a local or wide area network. The program includes data entry, filtering, downloading, and advanced querying of the database. It offers spreadsheet, graph, and form views of the data. JDesignerPro allows the developer to remotely access the system and perform customization through a Web browser. The program runs under Windows NT Server and other operating systems such as Unix and Linux. The most recent version of JDesignerPro allows for development on the Windows CE or the Palm OS operating systems.

Internet Reporting. The Internet Reporting program works with an ODBC data source and Windows NT. The program produces dynamic reports from Crystal Reports or SQL queries. Reports and selection criteria are easy to customize.

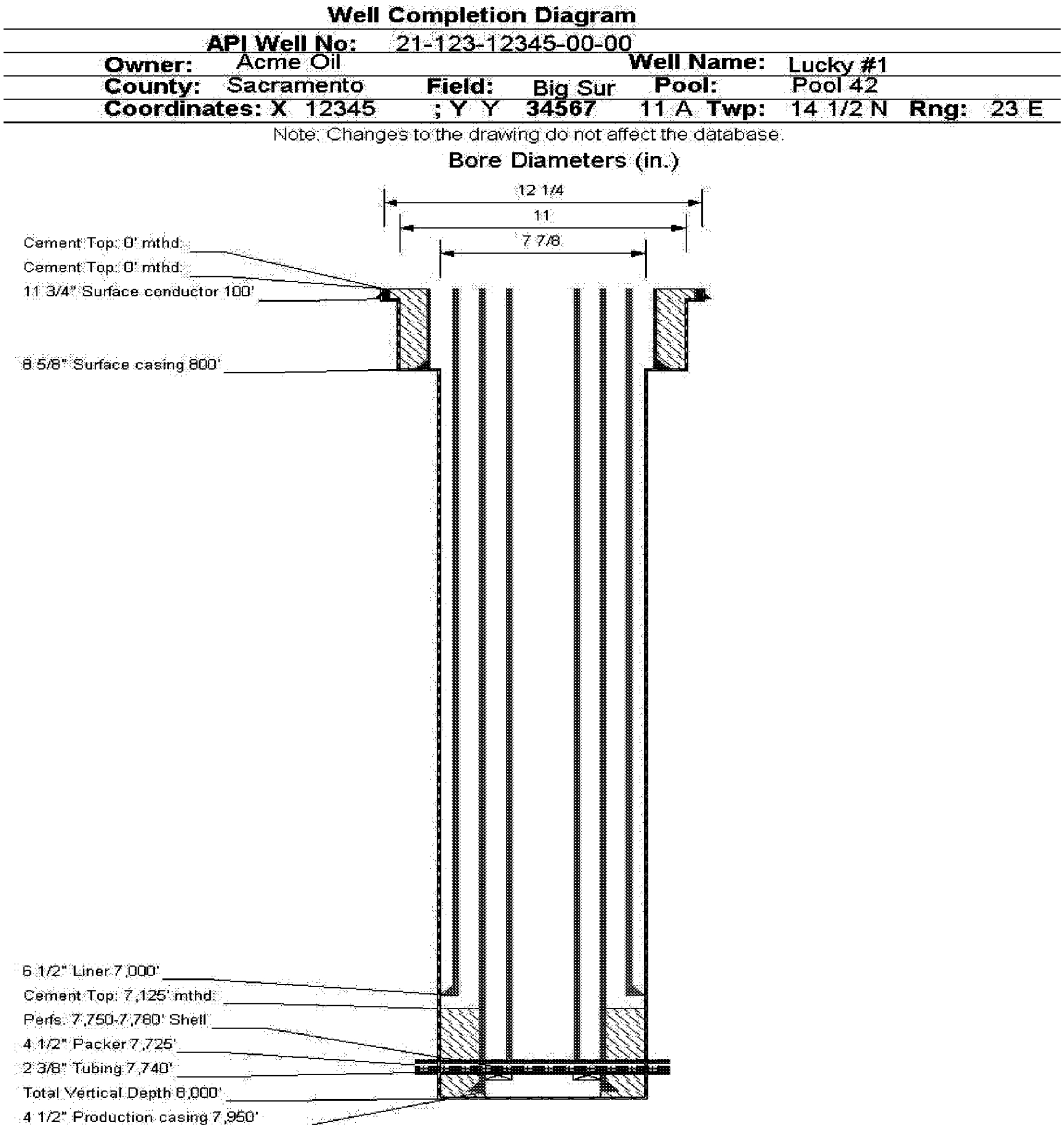
Static Report Download. Standard reports for oil and gas drilling, completion and production information can be made available for use with any data source accessible by SQL Server 7.0+ or Access2000. This Web program automates the creation of static HTML reports from SQL queries, stored procedures, and Access. The HTML reports are created on a Windows PC running SQL Server 7.0 and transferred to the Web server (any platform) on a user-specified schedule.

3. Wellbore Schematic Utility (WSU)

The WSU can be used as a visual tool to evaluate well construction details as a part of permit application programs and to generate review documents for well plugging and abandonment plans. Likewise, well owners and operators might find the utility helpful as a visual tool in the following activities:

- Performing volumetric cement calculations for well construction and plugging plans
- Preparing scaled design drawings of well construction details for application reviews of proposed wells
- Preparing as-built drawings for new wells

The WSU was developed as a means of simplifying and extending the use of ODBC environmental data sources. The application uses OLE automation developed through a Visual Basic interface to link Visio drawing capabilities with any Level2 ODBC environmental data source to render wellbore schematics instantly. Well construction and production zone information is read directly from the database. This information is then used to render a sealed diagram of the well instantly. The WSU can be customized to meet operations-specific requirements. A sample page of the output of the WSU, as it was customized for the American Petroleum Institute (API), is shown here.



4. Production Forecasting and Economic Evaluation Tool

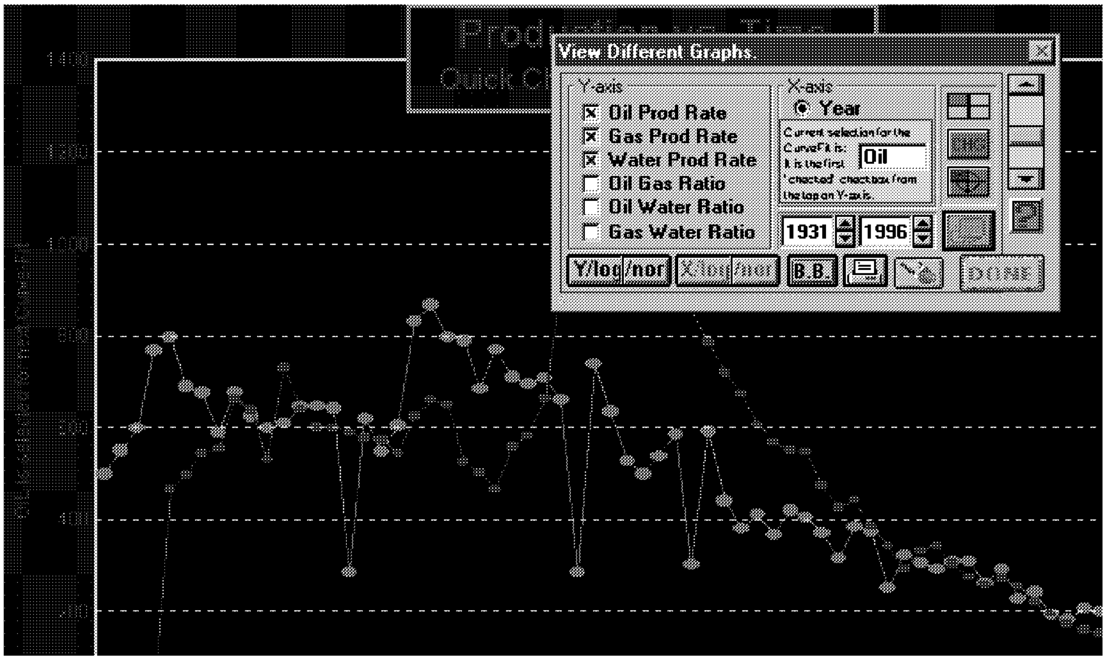
Oil and gas agencies constantly get requests for information about oil and gas production, forecasted production, and reserve estimates. Many states generate monthly or annual reports of production that include cumulative production totals and estimated reserves. Current methods vary significantly among states and may involve significant manual efforts, the results of which may or may not be saved for future evaluation or statistical analysis.

Many state oil and gas regulatory agencies depend on taxation from oil and gas production to provide operational funding. Production taxation may occur in a variety of forms, perhaps including a flat fee on production quantities (e.g., \$0.05 per MCF) or a percentage of sales. During time of declining production, state agencies in this situation must have the ability to forecast production to estimate income for budgeting and management decision-making.

Since RBDMS is the primary management information system for many state oil and gas agencies, production forecasting and economic evaluation tools that integrate with RBDMS could provide a broad range of benefits to individual agencies and industry.

In late 1999, the GWPC funded a Needs Assessment for a proposed Production Forecasting and Economic Evaluation Tool, which confirmed the desirability of such a tool.

Therefore, GWPC has moved forward with the initial design of the tool. In February 2000, the development team net to review a production forecasting tool that the California Division of Oil, Gas, and Geothermal Resources is now using. This meeting also established a plan for moving forward with development of the tool.



With this tool, users can observe the field preferences in many different ways before selecting the representative curve-fit.

5. GIS Utilities

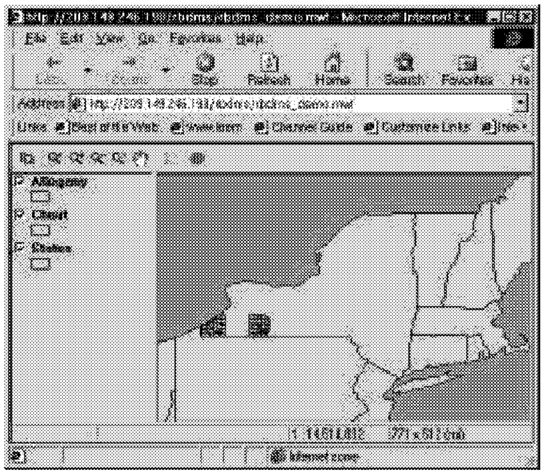
EIMS now includes a variety of GIS program options. Summaries follow.

Desktop GIS

The desktop GIS utility can be integrated with environmental databases that run in a client/server environment. This increased functionality adds a powerful dimension to data analysis by providing the ability to evaluate environmental data spatially. The EIMS GIS program shows data points such as well locations with respect to other available base map features. Thematic displays and data labeling are used to perform spatial evaluations of environmental data. Integration with environmental databases enables graphical selection of data and data editing.

Internet GIS

EIMS also offers the option of running a GIS program over the Internet. This program includes such features as pan, zoom, and find utilities; spatial display of environmental database output; spatial analysis with buffering, radius selects, point-on-polygon, and other tools; customizable reporting; and editable themes. The program supports ESRI, Autodesk, Intergraph, and other file formats. In addition to real-time data availability to state regulatory agency offices and industry operators, the Internet GIS option offers Web-based browsing without the need to install the data source locally.



6. Field Inspection Utility

The EIMS Field Inspection utility consists of a set of programs that assist with the tasks of scheduling UIC field inspections and efficiently entering field inspection data into the oil and gas agencies' database. The programs within the utility perform the following functions:

- Determine wells requiring annual Bradenhead inspections and five-year pressure tests.
- Allow the UIC District Office staff to customize inspection schedules by assigning inspections to inspectors on specific dates.
- Optimize inspection schedules by synchronizing inspection dates for all wells in a geographic area.
- Automatically print Notice-of-Inspection letters for mailing to operators.
- Download inspection schedules to inspectors' notebook computers.
- Minimize the time needed for inspectors to enter data in the field by displaying a scrolling list of all wells scheduled for inspections in the order in which they are to be inspected.
- Generate a file of completed inspections for uploading from the inspector notebook computers to the district servers.

Tested and now in use by the New Mexico Oil Conservation Division (OCD), the Field Inspection Utility minimizes the amount of work required to capture inspection data in the field and then to migrate that data to district and departmental systems. In New Mexico, inspection data is entered into notebook computers in the field when the inspections are performed. States that do not intend to provide field inspectors with notebook computers are able to use hard copies of the inspection forms and transfer the data to computers back in the office.

USER STATE PROFILES

Alaska

Agency Name:	Alaska Oil & Gas Conservation Commission
EIMS Components:	Custom RBDMS
Database:	
Front end:	Custom RBDMS Access 2000
Back end:	SQL 2000
Operating Systems:	Workstations: Windows 2000
Activity Summary:	

Through funding from the GWPC, the AOGCC is now moving to customize the generic version of the RBDMS program to meet their specific needs. Once added to the RBDMS utility set, some of these customizations will be beneficial to other RBDMS users.

For example, the ALaska version of RBDMS will include a new utility that allows users to create annual report formats as they are currently being generated on Main Frame within RBDMS. A total of 11 main reports with approximately 32 sub-reports are being customized. These reports will involve the creation of complicated production reports based in many cases on cross tab queries

The AOGCC RBDMS will also contain a module to account for Facility Tracking and Gas Disposition.

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Alabama

Agency Name:	Alabama Oil & Gas Board (AOGB)
EIMS Components:	Custom RBDMS
Database:	
Front end:	Custom RBDMS
Back end:	Access97
Operating Systems:	Server: Novell Netware; Workstations: Windows NT
Activity Summary:	

Through funding from the GWPC, the AOGB is now moving to customize the generic version of the RBDMS program to meet their specific needs. Once added to the RBDMS utility set, some of these customizations will be beneficial to other RBDMS users.

For example, the Alabama version of RBDMS now includes a new utility that allows users to filter on set criteria (such as location) from a number of RBDMS forms. Multiple new expanded UIC reports also now available. Additionally, the UIC monitoring system has been expanded, a datasheet version of the mechanical integrity test modules developed, data migration plans prepared, and performance enhancement improvements made in the custom system.

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Arkansas

Agency Name:	Arkansas Oil & Gas Commission (AOGC)
EIMS Components:	Custom RBDMS
Database:	
Front end:	Access2000
Back end:	SQL Server 7.0
Operating Systems:	Server: Windows NT; Workstations: Windows NT; Network: Novell/NT
Activity Summary:	

The AOGC has completed the migration from a legacy software system and hard-copy production cards that have been in-place since the 1950s to a multi-platform client/server information system. Data entry is currently handled by either directly entering data into RBDMS or by using a data entry system (DES) that includes a quality assurance manager and data flow manager for entry of intents, completion reports, and plugging reports.

New additions to AOGC's database include a custom production/proration management system with components for production data entry, gas well back pressure test handling, auto-calculation of allowables, and management of production reporting units, along with several other components. The AOGC has acquired consulting services for short-term database administration, data cleansing and manipulation, and training.

During the first week of RBDMS use, AOGC's Production Unit entered more than 2,800 data records. In February 2000, AOGC generated its first automated Allowables schedule from the system for natural gas production in north Arkansas. Other tools integrated into the AOGC's version of RBDMS include the following:

- A GIS tool that integrates the SylvanMaps ActiveX GIS control into the RBDMS Well Selection Criteria navigation system
- Basic wellbore schematic tool programmed directly in Access2000
- Graphical analysis tools that use ActiveX technology for analyzing production data and field activities
- Gas well back pressure test utility that auto-calculates allowables from the results of annual back pressure tests that AOGC requires of natural gas production operators in the state

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California

Agency Name:	Division of Oil, Gas, and Geothermal Resources
EIMS Components:	e.Permit, Wellbore Schematic Utility, e-inspect
Database:	
Front end:	WellStat and other Delphi applications
Back end:	SQL Server
Operating Systems:	Server, Windows NT; Workstations, Windows 95/98
Activity Summary:	

Department of Conservation

Starting with the electronic well permitting and data exchange system (e.Permit), the Division plans to automate much of the labor- and time-intensive regulatory oversight process for oil and gas well permitting. e.Permit uses the data already stored in the Division's database WellStat, and new data input to e.Permit is replicated back to WellStat.

e.Permit features reporting of permit application status, security, and data quality control through multiple tiers of immediate client-side, automatic server-side, and manual data integrity checks. Visitors to the Division's e.Permit Internet site will have two options for inputting data: HTML forms suitable for filing single applications and XML files suitable for batch uploads. Both data entry methods result in the same data handling procedures.

For industry operators whose databases do not support XML exports, the Division will offer e.PermitRemote so that operators can use Access to build a record set of the wells intended for Division review and export it to an XML file for uploading to e.Permit.

A bonus feature of the e.PermitRemote is the Wellbore Schematic Utility. With this utility, operators in California can render scaled well drawings instantly from information in the database. These drawings can then be uploaded to e.Permit as supporting attachments to the record set or used for other purposes in-house.

The Division also pioneered the use of an economic evaluation package, which has since been added as a new development effort in the EIMS toolset. Originally developed in Quattro Pro, this EIMS component is being redeveloped in Excel.

A new electronic field inspection is now being tested in the Bakersfield office. Based on this testing, the e-inspection system will be modified and used by many RBDMS states.

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Florida

Agency Name:	Florida Geological Survey
EIMS Components:	RBDMS Core Program
Database:	
Front end:	Access 97
Back end:	Access 97
Operating Systems:	Windows 95

Activity Summary:

The Florida Geological Survey completed a base installation of RBDMS in Access and linked to the existing Wells database. The installation included data migration, training, features to track field inspections, violations, and production, and features to track deadlines for permitting, testing by operators, and coverage of financial surety renewals. The Florida data has been imported into RBDMS. On-site training has been completed.

Kansas

Agency Name: Kansas Corporation Commission (KCC), Oil & Gas Conservation Division (OGCD)

EIMS Components: Custom RBDMS with components for handling Intents, well plugging, pits, UIC permits, Duplicate Handling System (DHS), LeaseTrack

Database:

Front end: Migrating to Access2000 (expected completion: March 2000)

Back end: SQL Server 7.0/Oracle

Operating Systems: Server: Windows NT; Workstations: Windows 95/98/NT

Activity Summary:

As the largest installation of RBDMS, KCC's OGCD boasts an inventory of 330,000 wells. Therefore, the KCC made several custom enhancements to RBDMS. For example, the State's spatial data on sensitive groundwater areas and river basins has been integrated for use in planning activities with respect to potential environmental priorities. The KCC also uses the database for tracking and permitting pits; managing intents to drill; handling plugging permits and final plugging records; maintaining operator licensing information; issuing automated letters for inspection planning and operator notifications; and working with other KCC software applications that reside in Oracle.

The presence of several duplicate records arising from an extensive legacy data conversion project led to the development of a DHS as part of a data quality management effort that the OGCD began. GWPC provided funding for the DHS.

OGCD tracks inspections on a lease basis as opposed to well-based inspections. The LeaseTrack system was developed to address inspection documentation needs. The system was populated from data maintained by the State's Department of Revenue and is now being deployed to District Offices for ongoing implementation.

To determine the feasibility of using palm devices for field data collection, OGCD began a prototype software effort to work with the LeaseTrack system. The project includes development of a palm application designed for the Palm OS operating system. Beta testing is now being done on a 3COM Palm Vx device; the application was developed with Puma Technology's Satellite Forms. System integration is being addressed with ActiveX technology available from Puma Technology and custom application development.

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Kentucky

Agency Name:	Kentucky Division of Oil and Gas (KDOG)
EIMS Components:	Core RBDMS with extensive customization , e-inspect
Database:	
Front end:	Access97
Back end:	Converting from a VAX Datatrieve system
Operating Systems:	Server, Windows NT; Workstations, Windows 95/98
Activity Summary:	

KDOG is in the process of converting its legacy database to the core version of RBDMS and customizing it to meet its operational requirements. The Kentucky add-on to RBDMS includes modules for Violations/Forfeitures, Permitting, Well Transfer, Tank Inspection, Idle Well, Gas Storage Fields, and Version Control. As a part of this programming, KDOG is re-creating the capability to generate notification letters that will be sent to the designated operators, bond companies, and banks.

To prepare for the migration from the legacy system, KDOG developed a procedure to transfer data from the existing VAX Datatrieve-based system into the RBDMS tables in an Access database, pending a final decision on the choice of database format. After evaluating several alternatives, including Sybase and Oracle, KDOG decided to upsize to SQL Server.

GWPC seized the opportunity to use Kentucky's experience in upscaling to SQL Server 7.0 as a practical training experience for member-states. Representatives from GWPC, Nebraska, New York, and Utah were present in Kentucky during the installation and configuration of the SQL Server software in February 2000.

Final conversion from the legacy system is being phased, with completion scheduled for late March 2000. The decision of whether to use an Access back end or a SQL Server back end is pending the results of rigorous testing now under way.

Beta testing of a field inspection utility using Arc Pad is underway in Kentucky. By using this system, a inspector can navigate to a well using GIS technology, double click on the well and pull up all RBDMS records relating to the well, including past inspections. The current inspection is entered in the field and the synchronized with the main data base back in the office.

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Michigan

Agency Name:	Michigan Department of Environmental Quality (DEQ), Geological Survey Division (GSD)
EIMS Components:	Custom RBDMS
Database:	
Front end:	Custom RBDMS
Back end:	SQL Server
Operating Systems:	Server: Windows NT; Workstations: Windows 95/98/NT

Activity Summary:

Michigan DEQ's GSD uses a highly customized version of RBDMS that includes the following components:

- Production/Proration System that uses stored procedures in SQL Server for rapid data analysis and viewing
- A compliance system that allows for tracking of multiple wells and/or facilities under a single case (or compliance record)
- A field activities system to track GSD's several million field activity records that include applications, permits (by permit number rather than by API well number), facilities, and complaints
- A well permitting system, which is configured to allow tracking and issuance of all GSD well permits and that handles standard permit language, proposed versus final data, and bonding
- A bonds and bond transfers system, which includes a comprehensive system for tracking bonds and handling the nearly 3,000 bond transfer requests the GSD receives each year
- A GIS tool that directly integrates the SylvanMaps ActiveX GIS control into the RBDMS Well Selection Criteria navigation system to allow spatial data queries, well filtering, and other common functions
- A basic wellbore schematic tool that is programmed directly in Access2000 to create a wellbore diagram along with completion data, formation tops, and other assorted well details
- Several Personal Data Systems (PDS's) programmed in Access97 for performing day-to-day functions

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Mississippi

Agency Name: Mississippi Oil & Gas Board (MSOGB)

EIMS Components: Core RBDMS, State-specific add-on, Internet Reporting Module

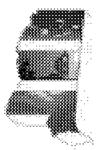
Database:

Front end: Access97

Back end: Access97

Operating Systems: Server, Windows NT; Workstations, Windows 95/98

Activity Summary:



The MSOGB has been using RBDMS since 1996. The installation uses the core version of RBDMS. The state-specific add-on handles Mississippi's UIC data.

A pilot-scale demonstration project in 1999 showed how the use of the RBDMS data source could be extended through the EIMS Internet Reporting module. The module is easy both to set up and to integrate with an ODBC data source. In Mississippi, the Internet Reporting module consists of a series of WebTools that have been integrated with RBDMS and Seagate's Crystal Reports version 7. No programming knowledge is needed to add custom reports.

A WebTool for security manages system usage, so reports can be limited to specific users and groups. Possible extended uses of the security program component might include cost recovery and system usage reporting. The selection criteria used for data reporting can be changed easily. System administrators can enter custom selection criteria without requiring program changes.

System components needed to implement an Internet reporting module includes an NT 4.0 Web server and Internet connection in addition to the ODBC data source, Crystal Reports, and WebTools.

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Missouri

RBDMS will be installed in Missouri in 2002. The work plan is currently under development. The final install will track both injection and production wells.

Montana

Agency Name:	Montana Board of Oil & Gas Conservation (MBOGC)
EIMS Components:	Custom RBDMS; Internet Reporting (Java)
Database:	
Front end:	Custom RBDMS
Back end:	SQL Server
Operating Systems:	Server: Windows NT; Workstations: Windows 95/98/NT
Activity Summary:	

The MBOGC has used RBDMS since its inception in the early 1990s. Montana's custom version of RBDMS includes components developed especially for the MBOGC, but also leverages other development performed in Michigan, Oklahoma, Ohio, and Kansas. The MBOGC's involvement in the RBDMS project has made this agency the first Division within the Department of Natural Resources and Conservation to implement a client/server-based system and to use a Java-based interface to a data system.

After development and rigorous testing, the MBOGC is in the process of deploying its Java interface to the RBDMS program, which was developed with Bulletproof's JDesignerPro software. The new Java tool allows dynamic data access via the Internet and also has the capability to run as an application over a local or wide area network. The tool includes the ability to allow data entry, filtering, downloading, and advanced querying of the database. Further, JDesignerPro allows the developer to remotely access the system and perform customization through a Web browser. Although the MBOGC has chosen to run the program on a Windows NT server, the software will run on other operating systems as well (e.g., Unix, Linux, etc.).

MBOGC is participating in the development of the RBDMS economic evaluation tools and is integrating GIS spatial analysis with RBDMS as the data source.

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Nebraska

Agency Name:	Nebraska Oil and Gas Conservation Commission (NOGCC) and the Nebraska Department of Environmental Quality (NDEQ)
EIMS Components:	**NOGCC:** Core RBDMS, State-specific production forms/reports **NDEQ:** Source Water Assessment data source
Database:	
Front end:	**NOGCC:** Access97; **NDEQ:** Access2000
Back end:	**NOGCC:** Access97
Operating Systems:	**NOGCC:** NT Server: NT Workstation: Windows 95
Activity Summary:	

The NOGCC was one of the original four state agencies to implement RBDMS in 1993. Since then, the NOGCC has used RBDMS to track UIC well data. In April 1998, the NOGCC implemented a custom production module that uses core RBDMS table structures and several forms and reports designed specifically for Nebraska. The NOGCC now uses RBDMS to track all oil and gas data.

In October 1999, the NOGCC completed a project in which every well drilled in the state was entered into RBDMS, along with pertinent well data. The NOGCC is now in a position to implement the Wellbore Schematic Utility. Once the latitude/longitude conversion is completed, NOGCC also will implement the EIMS GIS module.

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In a separate project for NDEQ, GWPC is overseeing the development of the EIMS source water management data source. The development of a technically sound database to store information from source water assessments will be one of the important first steps in launching the Nebraska Source Water Assessment Program (SWAP). This data management system will catalog and store the assembled source water assessments, assist NDEQ in source water management, and facilitate the reporting of this information to EPA and stakeholders. It also will feature the ability to generate vulnerability determination information and to inventory and identify contaminant sources.

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Nevada

Agency Name:	Nevada Bureau of Health Protection Services (BHPS)
EIMS Components:	Source Water Assessment data source
Database:	
Front end:	Access2000
Back end:	SQL Server 7.0
Operating Systems:	Server, Windows NT; Workstations, Windows 95/98
Activity Summary:	

The EIMS source water management data source is now completed for Nevada. This Access2000-formatted Source Water Assessment Program (SWAP) will provide the State of Nevada BHPS with a normalized database that will be suitable for housing information gathered as a result of the State's activities to inventory and catalog public water system supplies and potential sources of contamination. This system will give BHPS the ability to generate vulnerability determination information and inventory and identify contaminant sources. Staff will be able to use laptop computers to gather information in the field and then upload this information to the main database.

This EIMS utility will be compatible with the Safe Drinking Water Information System (SDWIS) for the following data fields: PWS ID, name, address, owner, operator, source, number of intakes, population served, and latitude/longitude.

The database will include modules to track groundwater and surface water vulnerability, model data, potential contaminant inventories, and PWS sanitary surveys. These component modules will be integrated so as to eliminate redundant data entry requirements.

The SWAP data source will provide the capabilities needed for groundwater vulnerability assessment and tracking of public water supply general system information. The data source also will house information about potential contaminant sources including contaminant source address, PWS source, latitude/longitude, ID well number, and distance (e.g., feet or meters) of potential contaminant source from PWS source. BHPS also will be able to perform vulnerability assessment and public water supply sanitary surveys with features of the SWAP data source.

RBDMS will be installed in Nevada in 2002. The workplan is currently underdevelopment. This install of RBDMS will have the ability to share data with the EIMS Source water program in the Nevada Bureau of Health Protection Services.

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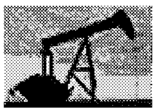
New Mexico

Agency Name:	New Mexico Energy Minerals and Natural Resources Department
EIMS Components:	Core RBDMS with customization; Field Inspection Utility
Database:	
Front end:	Access97
Back end:	
Operating Systems:	Server: Windows NT; Workstations: Windows 95/98
Activity Summary:	



The New Mexico installation of RBDMS is being customized to incorporate digital photographs, a basic wellbore schematic tool, auto-generation of all administrative permits, and a GIS module. Additionally, a great deal of legacy data will be moved into RBDMS as well as ONGARD so that users in the field will have ready access to pertinent data.

In the last year, effort has focused on ways to streamline field data collection while taking the inspectors' daily business routine into serious account. The New Mexico version of RBDMS was customized to include features for managing inspection schedules for multiple inspectors, producing well Bradenhead tests, and automating the field inspectors' daily trip report. New Mexico also outfitted its field inspectors with notebook computers, so field data acquisition in New Mexico is proceeding very successfully.

New Mexico's confidence in its ability to deploy the RBDMS data source and utilities to identify, act, and prevent potential damage to the State's underground sources of drinking water remains high.

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New York

Agency Name:	New York State Department of Environmental Conservation (NYSDEC)
EIMS Components:	Core RBDMS; Static Internet Reporting; Wellbore Schematic Utility; Field Inspection Utility; and XML Data Transfer
Database:	
Front end:	Access97
Back end:	Migrating to SQL Server 7.0 from Unify legacy database
Operating Systems:	Server, Windows NT; Workstations, Windows 95/98

Activity Summary:

The NYSDEC recently installed the core version of RBDMS and has been preparing a series of updates in a New York add-on. As part of the migration to SQL Server, data in Unify has been used to update an Access97 database. Work is underway to use the new linked server capability in SQL 7.0 to convert the Access97 import data utility to SQL Server. Once converted, the data import process will be a job launched by the SQL Server Agent as a series of stored procedures.

NYSDEC is adding electronic reporting capabilities to the well reporting module. An Access database with operator-specific information is being developed for each operator, along with an Access form for entering and editing the operator-specific information. These Access databases, which will be distributed to the oil and gas industry operators, will have the capability to create XML files for transferring updates to the New York version of RBDMS. Then, the data will be checked to ensure that the wells reported are assigned to the operator, thus replacing the manual, hard-copy based procedure used until now.

NYSDEC is developing a Permit Tracking Module. The module will use the same table structure as the e.Permit program so as to facilitate future implementation of the e.Permit program in New York. Because the permit review process is table-driven, the program will implement a series of review steps specific to each type of permit. The flexibility built into the permitting module will allow it to be used by multiple states by modifying data but not programs. When all of the steps have been completed and approved, a permit will be generated. Special conditions can be added, if needed.

NYSDEC also is updating its Production module. The Annual Well Report is now generated with data from Unify and will be updated to use the tables and fields from the New York RBDMS production system. NYSDEC has begun limited use of the Wellbore Schematic Utility and participated in the beta testing of the Field Inspection Utility.

New York is beta testing the RBDMS multi-lateral utility. This utility tracks the lateral and multi-lateral well locations.

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North Dakota

Agency Name:	Nebraska Oil and Gas Conservation Commission (NOGCC) and the Nebraska Department of Environmental Quality (NDEQ)
EIMS Components:	**NOGCC:** Core RBDMS, State-specific production forms/reports **NDEQ:** Source Water Assessment data source
Database:	
Front end:	**NOGCC:** Access97; **NDEQ:** Access2000
Back end:	**NOGCC:** Access97
Operating Systems:	**NOGCC:** NT Server: NT Workstation: Windows 95
Activity Summary:	

The North Dakota Industrial Commission (NDIC) is in the process of a base install of RBDMS that includes migration of legacy data, a custom inspection system, forms customization, Bottom Hole Location module (Montana version), SQL Server 2000 installation and data migration, and training. Future work will include additional customization and data refinement. Work has also begun on a field inspection utility. North Dakota will be using laptop computers to perform their field inspections.

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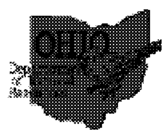
Ohio

Agency Name:	Ohio Department of Natural Resources (ODNR), Division of Oil & Gas
EIMS Components:	Custom RBDMS, Desktop GIS
Database:	
Front end:	Access97
Back end:	SQL Server
Operating Systems:	Server, Windows NT; Workstations, Windows 95/98/NT
Activity Summary:	



RBDMS was first expanded into a 32-bit client/server application in Ohio. ODNR also developed some enhancements to RBDMS that had lasting and positive effects in the program development. Some of these enhancements included a comprehensive location module to address the complex land-grid systems of Ohio; a permit application processing system with automated permit generation; a well stimulation module; a well plugging module; geological library maintenance system; geological library well card system; geologic data inquiry interfaces; expanded well history module; and additional reports and utilities.

Using RBDMS, Ohio has issued in excess of 4,500 permits to drill and plug wells; registered more than 750 well owners and transferred more than 8,000 wells since implementation in mid-1997. The database has grown from 80,000 wells to 110,000 with ongoing projects to bring the total to over 210,000.

ODNR offers a version of RBDMS to the Ohio oil and gas industry that can be updated weekly via an update program from the Division's FTP server. In 1999, the Division hosted several training sessions and assisted the PTTC in training the industry on the use of RBDMS. Industry users of RBDMS in Ohio account for over 50 percent of the well ownership in the state.

Ongoing enhancement efforts include implementing the production reporting/tax reporting module; compliance module; and online access to database records via Java script. In addition, Microsoft Index Server and Active Server pages provide the ability to search for well records based on data base fields or geographic information. Also, an "Emergency Response" module (under development by Argonne National Laboratory) will be linked to the system.

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Oklahoma

Agency Name:	Oklahoma Department of Environmental Quality (DEQ)
EIMS Components:	Source Water Assessment data source; Internet GIS
Database:	
Front end:	Being developed in Access2000
Back end:	To be determined
Operating Systems:	Server, Windows NT; Workstations, Web Browser
Activity Summary:	

The Oklahoma DEQ is in the process of making its water quality management data products available on the Internet. The EIMS Source Water data source stores water quality monitoring data from multiple sources that include both state and federal databases.

Internet users will be able to access this database, sort the data, and create reports. These data will be spatially displayed in a GIS browser. Public water supply consumer confidence reports also will be available by clicking on a source of drinking water on the GIS map.

This system combines data from all environmental programs (e.g., water quality, air quality, hazardous waste, oil and gas and injection wells) into one user-friendly database. Although the data source is being developed in Access2000 and SQL Server, it is being designed to be accessible by any database that can use Active Data Objects (ADO). More information is available at the following URL: **www.deq.state.ok.us/Water1/home/index.html**.

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Oklahoma Coorporation Commission

AT the request of the OCC, GWPC has been reviewing the OCC's Oracle database for possible conversion to RBDMS. After the system analysis is completed, GWPC will facilitate a data management peer review. A final decision on the conversion to RBDMS is expected in 2002.

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The Osage Nation

Database: RBDMS

Front end: **Access 97**

Back end: Access97

Activity Summary:

The Osage Nation has implemented the RBDMS system. This system assists with the administration of its environmental and natural resource programs. Because of the vast amount of information associated with oil and gas and UIC wells and the complexities of regulating UIC activities, the system performs many varied functions. The system includes features to track:

Underground Injection Permits
UIC Salt Water Disposal and Enhanced Recovery Injection Wells
Area-of-Review Studies
Oil and gas production wells
UIC Inspections

Mechanical Integrity Tests

Violations
Enforcement and Compliance Activities
Areas of Known Contamination
Water Quality Data

The system also includes Geographic Information System (GIS) capabilities to print and display maps depicting well locations, well status, aerial photographs, section lines, roads, streams, areas of known contamination, and other features

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Utah

Agency Name:	Utah Division of Oil, Gas and Mining (UDOGM)
EIMS Components:	Core RBDMS customized to include Data Synchronization Tool (DST)
Database:	
Front end:	Access97
Back end:	Access97
Operating Systems:	Server: Windows NT; Workstations: Windows 95/98/NT

Activity Summary:

Utah Oil Gas and Mining

Along with the deployment of a new oil and gas database, the UDOGM elected to implement the generic version of RBDMS after substantial research by several UDOGM staff members.

GWPC supported the implementation effort and funded the development of a Data Synchronization Tool (DST) to RBDMS from the Division's oil and gas database. Since completion of the implementation effort, the UDOGM has been successfully using a customized version of RBDMS and routinely replicates from the oil and gas database. The UDOGM staff is performing additional customizations.

UDOGM is planning to upsize to SQL 7 in the very near future. This will allow for the development of Web-based queries for oil and gas information. Additionally, the Division has plans to integrate oil and gas production information into RBDMS and an electronic permitting capability.

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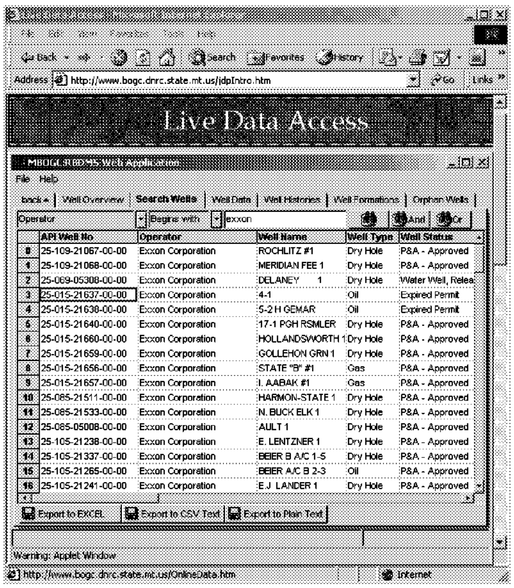
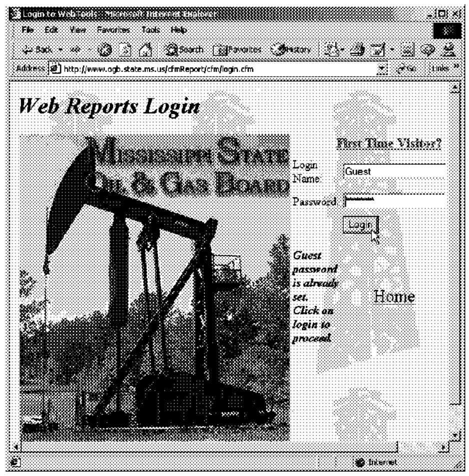
Web Reporting and Online Data Access

Several states have established Web sites for interested parties to access production data from their RBDMS data sources for downloading. Each implementation is slightly different, reflecting individual agency's needs and the variety of development tools that EIMS includes, such as Cold Fusion, Java, and XML.

New York and Mississippi are among those states that are using Cold Fusion and XML tools, while Montana has made extensive use of Java. GWPC recently funded the installation of Java Web data mining tools in Utah, Arkansas, and Michigan.





MBOGC: www.bogc.dnrc.state.mt.us/jdpIntro.htm

MSOGB: www.ogb.state.ms.us/cfmReport/cfm/index.cfm

NYSDEC: In testing for imminent release. For more information, contact Don Drazan (mailto:djdrazan @gw.dec.state.ny.us).

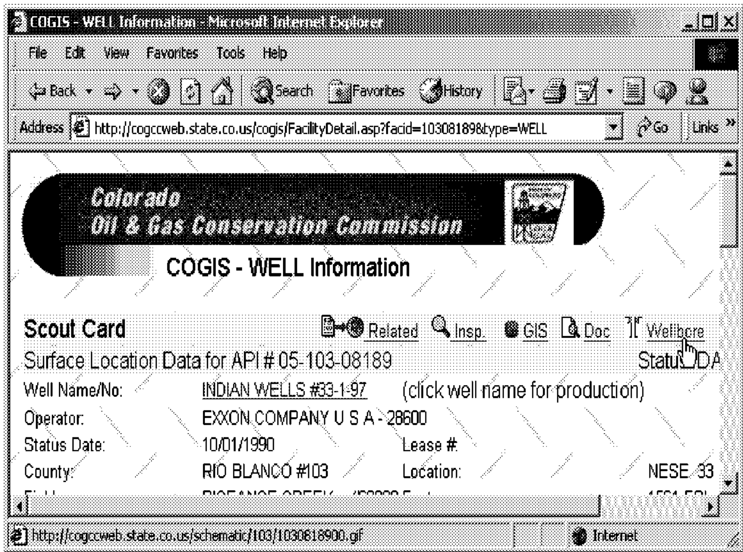
UDOGM: In testing for imminent release. For more information, contact Dan Jarvis (mailto:nrogm.djarvis@state.ut.us).

Wellbore Schematic Utility Upgrade (WSU)

In 2000, the WSU was Internet-enabled and installed at the Colorado Oil & Gas Conservation Commission's (COGCC's) office. Automated routines run the utility whenever well construction data in the SQL Server data source is updated. A table that contains a list of API well numbers for which construction information has been changed was added to the data source. As well construction-related data is changed, triggers on the tables automatically add the API well number to the table of changed wells. The WSU is automated to run on a schedule to read the API numbers from the table of changed wells and update the graphics file depicting each well. This automation has several advantages:

- Download is faster since the drawing already exists.

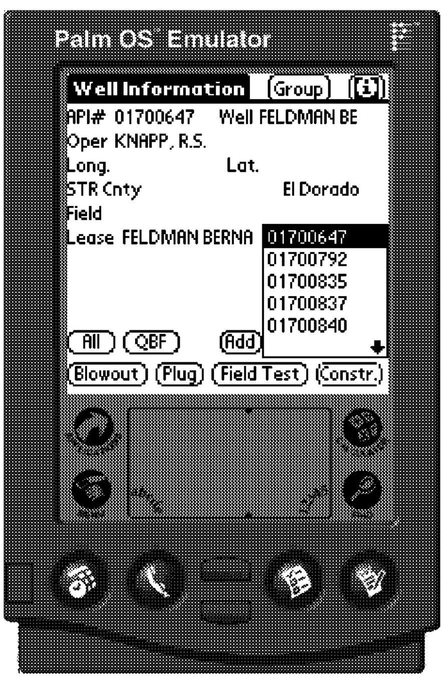
- No software except a Web browser is needed.
- Reliability and performance are improved over creating images "on-the-fly."



However, schematics can be generated on the fly if the WSU and Visio are running locally. This option may be desirable where a user wants to make changes to the drawing within Visio. Object Linking and Embedding (OLE) automation deployed through a Visual Basic interface links Visio drawing capabilities with any Level 2 ODBC environmental data source such as RBDMS. Well construction and zone information is read directly from the database to render a scaled diagram of the well instantly. COGCC's implementation of the WSU is at http://cogccweb.state.co.us. This installation also demonstrates the flexibility of the WSU because it is mapped to the COGCC's non-EIMS, independent data source.

Field Inspection Applications

Palmtop and Pocket PCs are being tested in several states in field inspection programs that upload to EIMS data sources such as RBDMS. GWPC has sponsored the development of Palmtop Device Applications (PDAs) for lease tracking, GPS data capturing, well plugging and abandonment, blowout prevention inspections, environmental inspections, mechanical integrity testing (MIT), and inspections and violations.



PDAs can be synchronized via the Internet. PDAs that run on the PalmOS perform synchronization operations with a server database via a TCP/IP connection and HTTP protocol. PDAs based on Windows CE and using SQL Server CE can perform a merge replication with a SQL Server database via an HTTP connection to SQL Server through Microsoft Internet Information Services (IIS).

The following agencies are participating in these field inspection data collection utility tests:

- California Department of Conservation

- New York State Department of Environmental Conservation
- Utah Division of Oil, Gas, and Minerals
- Alaska Oil & Gas Conservation Commission
- Colorado Oil & Gas Conservation Commission
- Nebraska Oil & Gas Conservation Commission
- Kentucky Division of Oil & Gas

The New Mexico Oil Conservation Division (OCD) is using notebook computers in the field to enter inspection data. This field inspection utility also works well with RBDMS, so states can match their choice of EIMS field utilities to several hardware platforms.

TRAINING AND TECHNICAL SUPPORT TO ALL STATES USING RBDMS/EIMS OR ITS MODULES

Over the three year grant project the RBDMS project team has provided a great deal to technical support to all nineteen states that have implemented the RBDMS or modules of the system. The State RBDMS Users Group has been supported through funding from the grant and it is the core group that has provided the direction for which the various subtasks are undertaken. Additionally this grant has provided detailed training to state agency representatives at three events during this past project year.

MOVING FORWARD: EIMS IN THE NEW CENTURY

Rick Simmers, Stan Belieu, and Tom Richmond have been instrumental in directing the development of RBDMS since its inception. Rick, Stan, and Tom form GWPC's RBDMS core advisory group. The vision statements that follow reflect this group's thoughts on the direction of the overall EIMS/RBDMS program.

Integrating RBDMS and Source Water Monitoring Data

A vision statement by Rick Simmers - OhioDNR

My vision for our group is very simple. I hope we are able to continue to provide a forum for state, federal, and industry officials to meet and exchange information and ideas.

So far, we have been able to provide specialized training that was not commercially available. New developments by our organization or by individual state or federal agencies have been an integral part of our group charter. Many new and exciting developments are outlined in this annual report. One logical next step is to pool our knowledge base for more widespread application through the development of the source water monitoring data source.

Let's hope this forum continues so we may all benefit from the cooperative developments and shared knowledge.

(Rick is the Administrator of the Division of Oil and Gas, North Region, ODNR)

Interagency Data Sharing

A vision statement by Stan Belieu

State regulatory agency databases are indispensable storehouses of information on all aspects of their regulatory programs. By tracking oil and gas, UIC, and other environmental programs and then making this data available to industry and the public, agencies make a valuable contribution to planning and resource development and protection within their respective jurisdictions.

Now suppose that oil and gas agencies could ease technological barriers to sharing this data nationwide. Then suppose that other types of programs, such as the newly emerging source water protection programs mandated by the SDWA Amendments, could benefit from this treasure trove of data. Making relevant data accessible to other state and federal agencies would make it possible to learn from other states' experience and to administer federal environmental programs with better accuracy, confidence, and cost-effectiveness. The economies of scale offered are tremendous.

GWPC took the first step toward this goal when it chartered the State Database Users Group. This group works to promote and foster a teamwork approach to developing and maintaining standards for information systems that state regulatory agencies can hold in common.

Emerging technologies are furthering the Users Group efforts in this regard, particularly the many options available to share information over the Internet. EIMS includes multiple tools for Internet sharing data—HTML forms, Java applications, and VisualBasic Web classes. One of the most promising techniques for sharing large quantities of data over the Internet is the eXtensible Markup Language (XML) format. With a properly formatted data schema, whole databases can be shared in one transmission over the Internet. The transmitted data can then be used to populate a second, target database.

Through focused workshops, the Users Group encourages participants to agree in setting priorities for new projects and on common data structures. Using both federal and state funds cooperatively to develop software modules that are readily adaptable to individual agency needs and reusable in other states then becomes an important springboard in standardizing information systems. Offering ongoing training opportunities in the use and maintenance of EIMS programs also is part of the Users Group charter.

I believe that we hve reached the critical mass needed to make interagency data sharing a realistic goal for the EIMA programs. We have tools. Now we need you continued commitment.

(Stan is the UIC Director of the Nebraska Oil & Gas Conservation Commission)

Industry Access Options

A vision statement by Tom Richmond

Real time data access has become a priority for industry and regulatory agencies alike. The Internet now has the capability to help industry and regulatory agencies communicate faster and more efficiently. This has the advantage of reducing data entry errors and, in some cases, decreasing the approval time for permitting activities. In the future, I envision that, anyone with an Internet connection and appropriately granted access rights will be able to access data now stored in state regulatory offices.

Recent advances in programming languages have enabled us to develop solutions for data compatibility and data sharing that were not available even a year ago. Recently, EIMS development has focused on providing these types of data access solutions to all states and industry, regardless of what data source the agencies are using. The following online features are planned or under development for EIMS:

- Electronic permitting and reporting
- Real time data accessibility for RBDMS production and UIC data
- Monitoring data and spatial mapping
- Online accessibility to utilities such as the Wellbore Schematic Utility and economic evaluation projections

More open access to these Web-driven database programs serves multiple industry interests. Assisting in oil exploration efforts is a primary example. Access to "well card" information can help operators target the search for oil reserves while balancing economic evaluation projections. The availability of such information also makes it possible to pursue oil exploration activities in environmentally conscious ways.

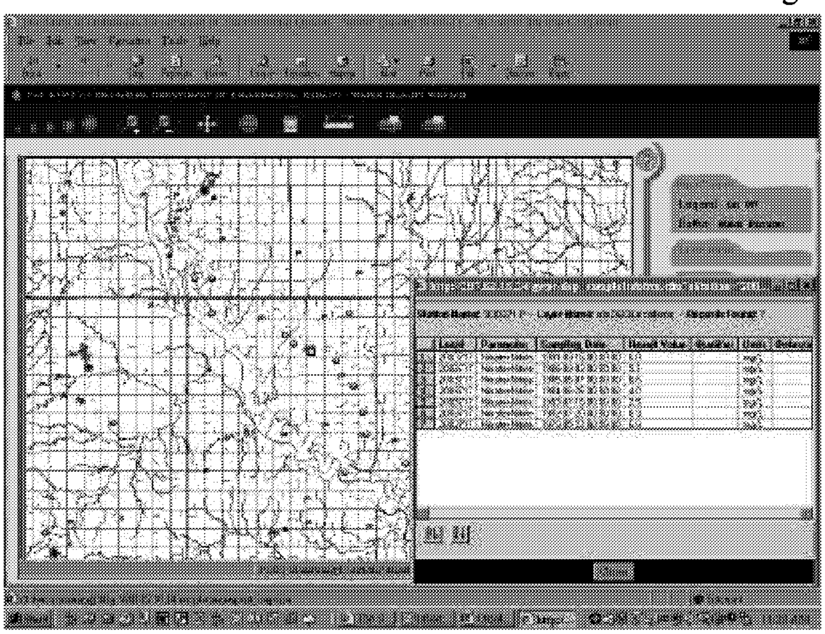
One of our main priorities in the EIMS development environment continues to be making data more reliable and more accessible to industry, regulatory agencies, and the general public.

I would like to take this opportunity express my appreciation to the Department of Energy for providing funding for this very successful program.

(Tom is the Administrator of the Montana DNRC, Division of Oil & Gas)

Source Water Assessment Database Development

The next major advance in GWPC's EIMS program is the Source Water Assessment database. This data source will be used to house information gathered as a result of the



states' activities to inventory and catalog public water system sources, as mandated by the SDWA Amendments. State source water protection agencies that use this data source will be able to generate vulnerability determinations, to inventory and identify contaminant sources, to track well log information, and export information to the federal SDWIS. The data source is being designed to be accessible by any database that can use Active Data Objects (ADO) technology. Also a part of this project is an online source protection reporting module that will gather information from state databases and make it available to EPA and the public.

Internet users will be able to access this database to create reports and view the data in both tabular and spatial formats. The GIS browser interface being developed for the Source Water Assessment database in Oklahoma is shown below. RBDMS data can be imported into the Source Water Assessment database where available, thus safeguarding America's drinking water through interagency data sharing.

The Road Ahead: Initiatives for 2002 & Beyond

Next Mileposts

Collectively, the current installations of EIMS data sources and utilities nationwide represent millions of data points. Regulators, industry, and the public now have opportunities for data mining and analysis for enlightened resource development and protection never before achieved.

To exploit these opportunities to make UIC, oil and gas production, and source water information widely available, GWPC is taking a Web-based approach for EIMS utility development, thus reducing client-side needs to a browser. The array of development tools GWPC is using ensures that EIMS utilities will be compatible with the widely differing server software requirements of state agencies. Here is a sampling of what GWPC has in development:

EIMS Utility	Status	Benefits	Future Development
Data Exchange	Use of well-formed XML is being tested in California for well permitting and in New York and Alaska for oil and gas production data reporting.	Streamlines and automates review and approvals processes. Reduces or eliminates duplicative permitting and reporting requirements.	An XML schema will be developed for bi-directional data exchange over the Internet. A pilot project with BLM is planned.
Wellbore Schematic Utility	A Web-enabled version of the WSU is online in Colorado.	View scaled drawings of wells from stored construction data for many purposes.	The WSU will be updated to include directional and multi-lateral wells and lithology data.
Field Inspection	Palmtop and Pocket PC apps are being tested in several states.	Reduces data entry error, saves money, and speeds data availability.	PDA development will focus on flexibility to accommodate wide variation in production data source structures.
Ad Hoc Querying	Versions have been developed with both Crystal Reports and Java. Testing in several states is ongoing.	Allows Internet users to access a database, design custom reports, and download data.	Upgrades to allow more user flexibility in report writing are planned.
EIMS Utility: Coal Bed Methane Wells	Planning phase underway.	Incorporates coal bed methane wells into RBDMS	

Electronic Data Transfer with BLM

GWPC has led the charge in exploring the potential e-commerce technology offers for data sharing among regulatory agencies.

The Future of Online Permitting

GWPC has helped to demonstrate that oil and gas operators can now upload many permit applications to a Web server that runs multiple levels of data integrity checks. Once the checks are passed, the data is accepted for upload to the production data source. Ad hoc queries can be used to track individual permit applications as they are processed through a largely manual review cycle.

GWPC anticipates that soon such XML data can be e-mailed directly to a POP-3 mail server address. EIMS data sources such as RBDMS can be programmed to retrieve the e-mail, run the integrity checks, and then notify both agencies and operators as to status changes throughout the review and approval process through automated e-mail transmissions in addition to ad hoc queries.

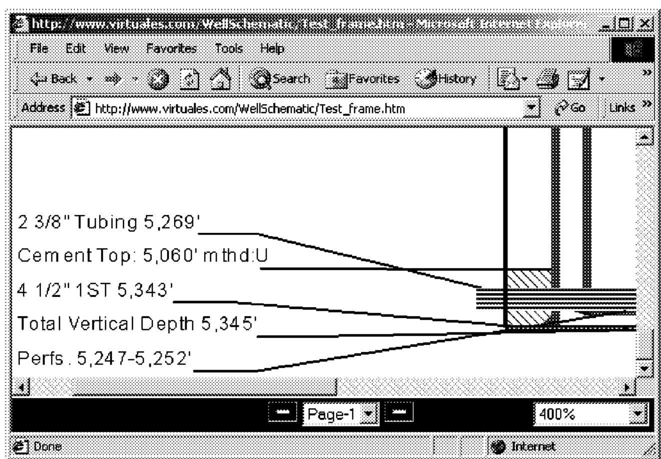
Already, through pilot studies and demonstration projects, GWPC has shown how eXtensible Markup Language (XML) programming can ease process bottlenecks for regulatory agencies and oil and gas operators. Two such projects are the California e.Permit system and the oil and gas production reporting in New York.

Now GWPC is taking the next step. A joint effort with the Bureau of Land Management (BLM) to develop an XML schema is underway. Colorado, Nebraska, Alaska and the BLM are participating in the pilot program. The XML schema under development will allow an operator to use the Internet to simultaneously send permit applications to state and federal agencies. Use of the schema will make exchanging datasets possible between AFMSS and RBDMS. Anticipated benefits:

- Greater data accessibility will improve regulatory decision-making across the boundaries of federal- and state-managed lands.
- Duplicative reporting requirements between state and federal agencies will be reduced.
- Drilling permit approval processes will be streamlined.

New Wellbore Schematic Utility Features

Oil and gas regulatory agencies can use the WSU as a visual tool to evaluate well construction details as a part of permit application programs and to generate review documents for well plugging and abandonment plans. Likewise, well owners and operators might find the utility helpful as a visual tool in activities ranging from performing volumetric cement calculations for well construction and plugging plans to providing documents to support permit applications.



Enhancements to the WSU to show multilateral and directionally drilled wells, downhole locations (up to 50 x, y, and z coordinates), and lithology and other zone information are now under way. Another feature option available to Internet Explorer users is a scrollable and zoomable view of the schematics that does not lose resolution, thanks to the use of a vector graphics format.

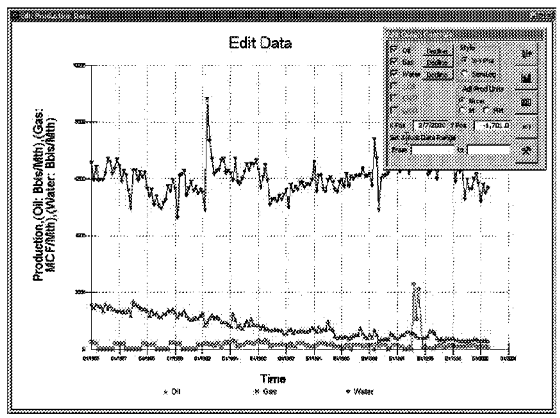
Extended Field Inspection Application Development

GWPC plans to sponsor the development of a single palmtop device application (PDA) that will have the flexibility to serve seven oil and gas agencies. Five of these agencies use custom versions of RBDMS. Two use other, completely independent SQL Server data sources. The application developed under this scope of work will consist of four separate modules:

- Plugging/Abandonment
- Blowout Prevention
- Environmental Inspection
- Geographical Information System (GIS) data

Production Forecasting and Economic Evaluation Tool

Accurately forecasting oil and gas production is a critical element for state regulatory agencies and industry. The EIMS Production Forecasting and Economic Evaluation Tool (PFEET) uses standard petroleum engineering techniques to predict oil and gas reserves and future life of wells/leases. It also can filter the production data to provide data grouping in a user-desired format. The results of the analysis are stored for later review by the user.



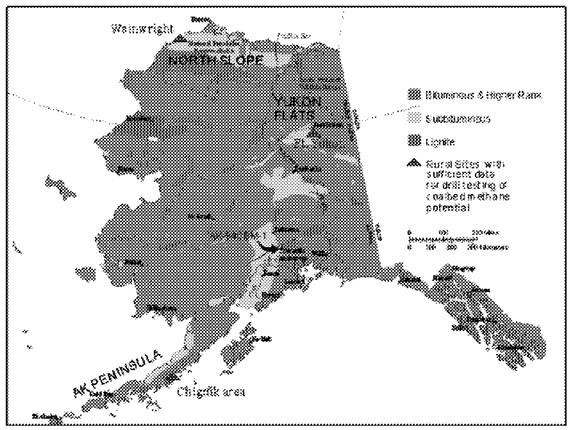
PFEET reads production data (volume/time data pairs) from the data source and allows the user to perform decline curve analysis. PFEET is now configured to use data from Nebraska, Montana, Arkansas, and California. The tool has the ability to filter the production data in individual production reporting units (wells or leases), oil/gas fields, and individual operators. Future work envisioned on the PFEET application includes the following:

- Expanding analysis techniques to include P/Z gas forecasting and polynomial curve fitting predictions
- Expanding the economic forecasting and present worth calculations module
- Providing for tax incentive calculations for operators
- Adjusting declines for workovers performed on a well
- Publishing and accepting XML data structures
- Generating Web-based data deliverables from Java data mining tools also developed for GWPC

Core RBDMS Update
GWPC is in the process of updating the generic RBDMS to address known bugs and to plow user feedback into the product. As a result, the new "core" version of RBDMS is expected to be a lighter, faster-performing application. Periodic status reports will be made available through the Technical Advisory Group meetings and communications. GWPC expects that this work will be completed in 2001

Coal Bed Methane Wells
Coal bed methane accounts for about 7.5 percent of total natural gas production in the U.S. Production experience and the environmental implications of recovering coal bed methane are of vital interest.

A 1999 report from the Gas Research Institute attributes 39 trillion cubic feet (TCF) of natural gas to the coal beds of the Powder River Basin in Montana and Wyoming, 3.7 TCF to coal basins entirely within Montana, and another 3 TCF to the Bighorn Basin in Montana and Wyoming. Alaska's coal resources may exceed 5.5 trillion short tons and may contain up to 1,000 TCF of gas. Development of natural gas from coal beds presents unique challenges to agencies to implement a regulatory framework that uses good science and good judgment to manage the impacts of development.



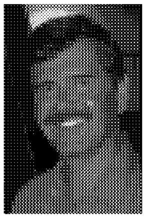
Because of the nationwide interest in this resource, the RBDMS Core group is planning ways to incorporate the successes of RBDMS into coal bed methane technology. The focus will be on permitting, tracking production, monitoring water quality, and monitoring environmental compliance in coal bed methane deposits. Through the RBDMS model, the permitting process can be streamlined without reducing environmental compliance. The GWPC is currently conducting a needs assessment survey to determine the necessary data elements for coal bed methane tracking. Results of this survey should be available by January 2002. States and industry have requested this module because of the increase in permit applications for coal-bed methane wells. Colorado now reports that they are permitting more coal bed methane wells than conventional natural gas.

Help Systems
A commitment to making the software GWPC develops user-friendly extends to help systems. In the coming year, developing detailed RBDMS documentation will be a priority. This effort will focus on updated and expanded administrators' and users' manuals.

An example of a multimedia format useful for online tutorials can be downloaded from ftp://gwpc.site.net/eims/e_permit/EPermitDemoavi.exe. This PC desktop video format also can be used with or without audio inside Windows help files as *How To* topics.

GWPC is producing audio/video help and training systems for RBDMS users. These files can be viewed on a personal computer and assist in training new RBDMS users. The video help files were demonstrated in Reno and will be finalized in early 2002.

The Road Ahead: EIMS Initiatives for 2001 & Beyond - Vision Statement



The DOE's grant programs, such as the one funding RBDMS development, tie into such huge responsibilities as running the National Labs, developing the national energy policy, overseeing nuclear energy programs, and providing technical support for the national defense systems. For GWPC and the RBDMS member-states to have received even a nomination for one of the 100 Points of Light awards was quite significant. To actually receive one of the awards is indeed a great honor.

Working with the dedicated member states and GWPC staff has been a very rewarding experience. Our shared goal of implementing a common nationwide system of data tracking for the oil and gas exploration and producing industries has been a success. Frequently, organizations become narrow-minded, adopting the stance that their internal procedures and policies are somehow inflexibly unique to themselves. Through RBDMS, states are finding common data management issues in regulatory programs and in providing information to the public and industry. The close cooperation between member-states and the GWPC staff and its consultants has been key to our success to date. Approximately twenty states are now using RBDMS or an EIMS utility. While some modifications are necessary to meet state-specific program needs, the ability to build on others' experience has saved money and improved the product. This is the cornerstone of EIMS development in general and of RBDMS evolution in particular. Western states and eastern states can find commonality in inspection utilities, economic evaluations, and other EIMS tools.

As EIMS/RBDMS opens its second decade of development, new priorities and opportunities open to member-states. The client/server environment, Web-based access, GIS functionality, and PDAs are areas of current development. A primary focus is on data exchange with the XML protocol. The development of a common data dictionary between the states will allow industry partners to provide data in a single format. EIMS utilities will be created to integrate this data seamlessly into states' data managment system. With a free flow of information in a streamlined process of reporting, regulatory decision-making and oil and gas exploration and development efforts can be substanially improved across state, federal, and private lands. Toward that goal, GWPC will be working with BLM to coordinate the filing of regulatory notices from companies to state agencies. Here is to the promise of the first step toward a truly seamless nationwide data trust!

Don Drazan works for the Division of Mineral Resources within the New York State Department of Environmental Conservation. He has actively participated in the RBDMS initiative since March 1999.

Acknowledgements

EIMS and its flagship application RBDMS are successful because the state agency personnel who use it to make their operations run more efficiently direct the software development. We are proud to be adding more functionality to this system and we look forward to helping more state agencies use EIMS/RBDMS or one of the utilities. We would like to take this opportunity to acknowledge the many individuals whose dedication continue to make this program a success.

U.S. Department of Energy: Nancy Johnson, Dave Alleman, Bill Hochheiser.

State Oil and Gas Agency Personnel Responsible for Implementing RBDMS and Other EIMS Utilities: New York, Don Drazan; Florida, Ed Garrett; Ohio, Rick Simmers, Gregg Miller; Kentucky, Rick Bender, Bill Adkins; Mississippi, Walter Boone; Alabama, Dave Bolin; Michigan, Jim Elsener; Arkansas, Gary Looney, Jason Hammock: Kansas, Maurice Korphage; Nebraska, Stan Belieu, Bill Sydow, Mary Wistrom; North Dakota, Mark Bohrer; Montana, Tom Richmond, Jim Halvorson; Utah, Dan Jarvis; California, Mike Stettner; Alaska, Elaine Johnson, Steve Davies.

State Agency Personnel Responsible for Directing the Development of EIMS/RBDMS:

Co-Chairs: Tom Richmond and Stan Belieu.

Members: Don Drazan, Mark Bohrer, and Rick Simmers (alternate).

RBDMS Technical Group: Mary Wistrom, Dan Jarvis, Jim Halvorson, and Ben Stone. and Bill Adkins.

GWPC/GWPRF: Mike Paque, GWPC Executive Director - mike@gwpc.org . Ben Grunewald, GWPC Associate Director - ben@gwpc.org . Paul Jehn, GWPC Technical Director – pauljehn@televar.com

The following are summaries of work completed during report period to fulfill the three-year grant project objectives and overall project Task 3.

Cost Effective Regulatory Approach (CERA) Effort: The Ground Water Protection Research Foundation (GWPRF) has spearheaded an effort to seek and foster the development of new approached that can benefit the petroleum industry as well as related government agencies. These efforts by the Foundation are commonly referred to as the "Cost Effective Regulatory Approach" or CERA projects.

CERA Project: Development of a Study to Investigate Various State Programs Regarding Waste Fluids Eligible for Injection into Class IID Injection Wells: The purpose of this project is to accumulate background information that will lead to development of a informative research study. The purpose of the study is to identify and document on a state-by-state basis waste fluids eligible for disposal into Class IID injection wells in Section 1425 state and Section 1422 direct implementation (DI) state underground injection control (UIC) programs. In addition, the survey will also identify and document the process used by each state to approve waste fluids for disposal into Class IID injection wells.

On June 30, 1999 representatives of the GWPRF CERA project team met to discuss the next step necessary in the effort to monitor and influence the current and future development or policies and/or regulations regarding eligible waste fluids for Class IID injection wells. It was determined at this meeting that a proposal be developed for a study which would reveal the variations among state programs regarding this issue. By mid-July a draft proposal was developed and work continued through Fall 2000.

The draft final report entitled, "Survey on Waste Fluids Eligible for Injection into Class II Disposal Wells" is as follows:

INTRODUCTION

The National Underground Injection Control (UIC) Technical Work Group of the United States Environmental Protection Agency (EPA) has developed a draft report entitled *Waste Fluids Eligible for Injection Into Class IID Injection Wells*. Many state regulatory agency members of the Ground Water Protection Council (GWPC) expressed concern that the draft report did not reflect actual practice in UIC programs across the nation. In response, GWPC and the Ground Water Protection Council Research Foundation (GWPRF) conducted a survey of primacy and direct implementation (DI) states to gather comprehensive information on the types of fluids the states and EPA regions have authorized for injection into Class II disposal wells.

SURVEY DESIGN

All states and EPA regions with primacy or DI programs were asked to complete the survey questionnaire so comparisons could be made of the fluid types eligible for disposal into Class II wells in different programs. To avoid any preconception or bias the GWPC and GWPCRF members might have introduced into the survey, the questionnaire was developed with the support of representative states from EPA Regions 5 through 10 and also with the support of the EPA National UIC Technical Work Group. The questionnaire was sent to 29 states and 8 EPA Regions. EPA administers DI programs in six of the states.

SURVEY FINDINGS

Based on the responses in the returned questionnaires, the states and EPA regions were classified into five categories based on the criteria they use to define wastes eligible for disposal in a Class II well. The categories are:

(1) Oil and gas exploration and production exempt waste plus non-hazardous non-exempt waste directly associated with the exploration and production of oil and gas that are mixed with oil and gas exploration and production exempt waste.

(2) Oil and gas exploration and production exempt waste.

(3) Fluids that are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Also included are exploration and production wastes that are classified as non-hazardous by the California Division of Oil, Gas and Geothermal Resources based on the California assessment manual on a case-by-case basis.

(4) Fluids that are brought to the surface in connection with conventional oil and natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as hazardous waste at the time of injection. Also included are certain fluids from beyond the lease custody transfer boundary that test non-hazardous waste using the Toxicity Characteristic Leachate Procedure (TCLP).

(5) Fluids that are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Also included are other fluids identified in a policy statement by Michael B. Cook, Director of the EPA Office of Drinking Water, on July 31, 1987.

After assigning each state and EPA region to a category based on the survey responses, the project team contacted the states and EPA regions to confirm the assignments. Table 1 summarizes this process.

Table 1

State	Received Form	Send Category	Confirm Category
Alabama	Yes	yes	Yes
Alaska	Yes	yes	Yes
Arkansas	Yes	yes	Yes
Arizona	Yes	yes	Yes
California	Yes	yes	Yes
Colorado	Yes	yes	Changed to #5
Florida	Yes	yes	Yes
Idaho	No		
Illinois	Yes	yes	Yes
Indiana	Yes	yes	Yes
Kansas	Yes	yes	Changed to #2
Kentucky	Yes	yes	Yes
Louisiana	Yes	yes	Yes
Maryland	Yes	yes	Yes
Michigan	Yes	yes	Yes
Mississippi	Yes	yes	Yes
Missouri	No	yes	Yes
Montana	Yes	yes	Yes
Nebraska	Yes	yes	Yes
Nevada	No	yes	Yes
New York	No	yes	Yes
New Mexico	Yes	yes	Yes
North Carolina	Yes	yes	Yes
North Dakota	No	yes	Yes
Ohio	Yes	yes	Yes
Oklahoma	Yes	yes	Yes
South Dakota	Yes	yes	Yes
Tennessee	Yes	yes	Yes
Texas	Yes	yes	Yes
Utah	Yes	yes	Yes
West Virginia	Yes	yes	Yes
Wyoming	Yes	yes	Yes
EPA Region #3	Yes	yes	Yes
EPA Region #4	Yes	yes	Yes
EPA Region #5	Yes	yes	Yes
EPA Region #6	Yes	yes	Yes
EPA Region #7	No	yes	Yes
EPA Region #8	Yes	yes	Yes
EPA Region #9	Yes	yes	Yes
EPA Region #10	Yes	yes	Yes

Figure 1 and Table 2 show the best fit for each state and EPA region among the five categories. The results reflect the range of waste eligibility determinations worked out during the last twenty years through discussions between primacy states and the EPA regional offices. With just three exceptions, all of the primacy state programs fall in Categories 1, 2, and 3. All of the EPA regions except one fall in Category 5.

Figure 1

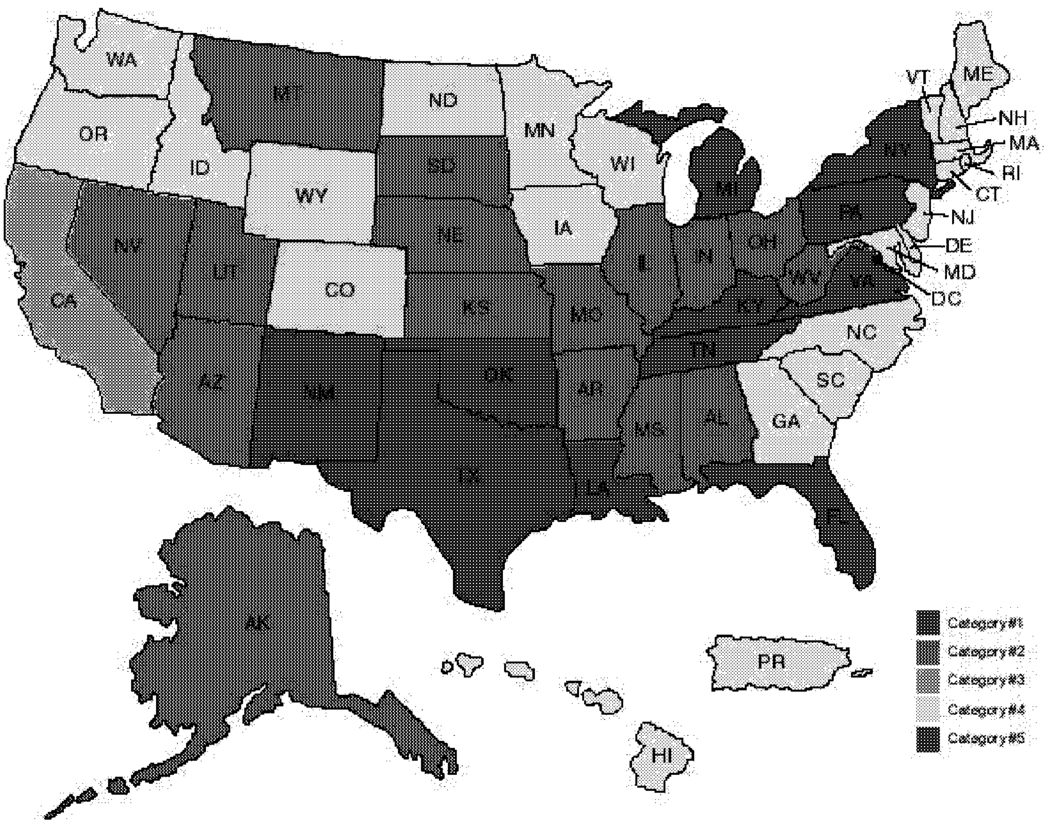


Table 2

Category#1	Category #2	Category #3	Category #4	Category #5
Louisiana	Alabama	California	Colorado	EPA Region 3
New Mexico	Alaska		North Dakota	EPA Region 4
Oklahoma	Arizona		Wyoming	EPA Region 5
Texas	Arkansas			EPA Region 6
	Illinois		EPA Region 8	EPA Region 9
	Indiana			EPA Region 10
	Kansas			
	Mississippi			Florida
	Missouri			Kentucky
	Montana			Michigan
	Nebraska			New York
	Nevada			Pennsylvania
	Ohio			Tennessee
	South Dakota			Virginia
	Utah			
	West Virginia			

All of the states in Category 1 are located in EPA Region 6. Arkansas, Montana and the primacy states in EPA Regions 4, 5, 7, and 9 make up Category 2. California, the only state in Category 3, has developed its own list of non-hazardous wastes that are eligible for Class II disposal.

States in Categories 4 and 5, with some variations, use EPA's definition of a Class II well as a basis for determining wastes eligible for Class II disposal. Colorado, Wyoming, and North Dakota, as well as EPA Region 8, make up Category 4. They allow some flexibility for fluids generated beyond the lease custody transfer boundary that test non-hazardous using the TCLP. The remaining states and EPA regions, which fall in Category 5, use the definition of a Class II well, as expanded by EPA policy statements issued after 1982.

DICUSSION AND ANALYSIS

Figure 2 shows the percentage of Class II disposal wells by category. Approximately **61% of Class II disposal wells** are regulated by Category 1 states with primacy under Section 1425 of the Safe Drinking Water Act (SDWA). Another **26% of Class II disposal wells** are regulated under Section 1425 state primacy programs in Category 2.

Figure 2

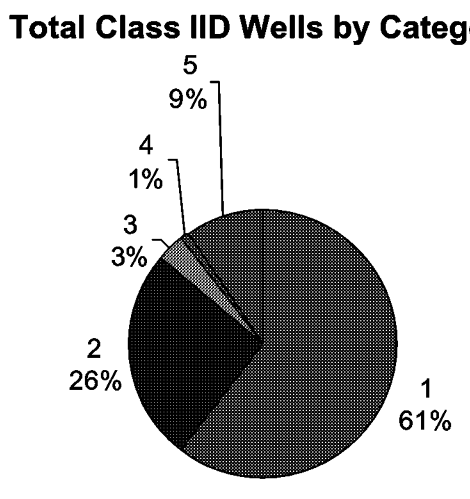
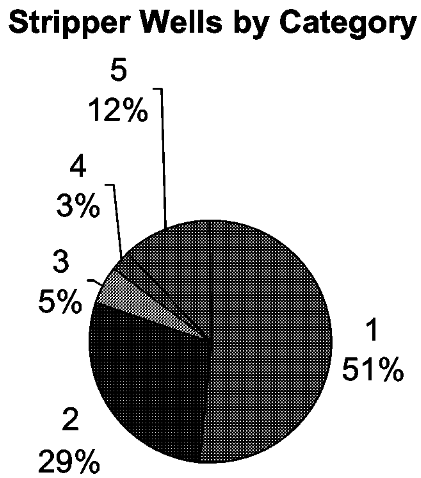


Figure 3 depicts the number of stripper wells by category based on information from Hart's E&P in its special statistical issue of *Petroleum Independent,* the official magazine of the Independent Petroleum Association of America (IPAA). Stripper wells produce less than 10 barrels of oil per day and are highly sensitive to regulatory compliance costs.

Figure 3



The scope of this study did not include a detailed analysis of the costs of restricting the wastes eligible for disposal in a Class II well. Neither did this project analyze the costs versus the environmental benefits of restricting any particular waste from Class II disposal. These considerations, however, would have a bearing on EPA's policy decisions regarding Class II fluids because of the provision in the Safe Drinking Water Act (SDWA) prohibiting EPA from promulgating regulations that impede the production of oil and gas.

CONCLUSIONS
This survey shows that the concerns of the state regulatory agencies administering primacy programs are well founded. Most oil and gas producing states have been operating under SDWA Section 1425 primacy agreements since the early to middle 1980s. Under these primacy agreements, the State Directors have acted in accordance with EPA's decision that:

> . . . national minimum standards are not the appropriate place to classify all individual practices, some of which may be unique to geological and hydrologic conditions or the regulatory program peculiar to one or a few states. The classification scheme is intended as a framework for State Directors and the decision to place . . . borderline wells in one class or another shall be made on a case-by-case basis. 47 Fed. Reg. 4995 (February 3, 1982).

By restricting the flexibility and discretion of the State Directors to determine fluids eligible for disposal in Class II wells, the draft conclusions of the National UIC Technical Work Group would affect large numbers of injection wells and the oil and gas production associated with them.

This draft report has been sent to Cynthia Dougherty at EPA's Office of Ground Water and Drinking Water and to GWPC membership for review. In conjunction with the survey that led to the development of the above report, Mr. Bill Freeman of the project team developed the following report that support the conclusions reached during the state survey effort.

A 2000 Regulatory Review Addressing Fluids Eligible For Class IID Injection
By Bill Freeman

Preface

In 1999 the National Underground Injection Control (UIC) Technical Work Group of the United States Environmental Protection Agency (EPA) developed a draft report entitled ***Waste Fluids Eligible for Injection Into Class IID Injection Wells***. Many state regulatory agency members of the Ground Water Protection Council (GWPC) expressed concern that the draft report did not reflect actual practice in UIC programs across the nation. In response, GWPC and the Ground Water Protection Research Foundation (GWPRF) conducted a survey of primacy and direct implementation (DI) states to gather comprehensive information on the types of fluids the states and EPA regions have authorized for injection into Class II disposal wells.

This survey showed that the concerns of the state regulatory agencies administering primacy programs were well founded. Most oil and gas producing states have been operating under SDWA Section 1425 primacy agreements since the early to middle 1980s. Under these primacy agreements, the State Directors have acted in accordance with EPA's decision that: . . . national minimum standards are not the appropriate place to classify all individual practices, some of which may be unique to geological and hydrologic conditions or the regulatory program peculiar to one or a few states. The classification scheme is intended as a framework for State Directors and the decision to place . . . borderline wells in one class or another shall be made on a case-by-case basis. 47 Fed. Reg. 4995 (February 3, 1982).

By restricting the flexibility and discretion of the State Directors to determine fluids eligible for disposal in Class II wells, the draft conclusions of the National UIC Technical Work Group would have affected large numbers of injection wells and the oil and gas production associated with them.

A committee formed by the Ground Water Protection Research Foundation to develop and oversee the state survey asked Bill Freeman, retired from Shell Oil Company, and a longtime member of the American Petroleum Institute and the GWPC, to compile the documents containing facts that support the conclusions reached as a result of the 1999 GWPRF State Survey. This document entitled, ***A 2000 Regulatory Review Addressing Fluids Eligible for Class IID Injection*** was written by Bill Freeman and reviewed by Lori Wrotenbery - New Mexico Oil and Gas Director; Jerry Mullican – former Texas Oil and Gas Director; Dick Staments – former, New Mexico Oil and Gas Director; Marty Mefferd - former, California Oil and Gas Director; Bill Bryson – former, Kansas Oil and Gas Director; Mike Paque – GWPC Executive Director; and Ben Grunewald – GWPC Associate Director.

The history of events, letters, and rule interpretations compiled in this document and any opinions expressed are solely those of the author. However, the reviewers, as individuals, attest to the overall accuracy of this document.

A 2000 Regulatory Review Addressing Fluids Eligible For Class IID Injection
By Bill Freeman

Executive Summary

Until 1992, it appeared that the EPA, states and industry collectively understood the definition of fluids eligible for injection into Class IID wells. The last time fluids eligibility came into question officially was in 1987 for air scrubber and water softener regeneration brines in California, which was easily resolved in Washington. In 1992, the fluids eligibility issue again reared its head in Region VI, but was thought to be resolved by the Agency in 1993. In 1997, however, the issue became serious as the EPA National UIC Technical Workgroup attempted to grapple with fluids eligibility on a national basis due to problems in Alaska. As a result, in 1999 the Ground Water Protection Council (GWPC) implemented a past Regulatory Review and a State Survey to determine if eligible fluids for injection into Class IID wells could be reasonably interpreted. Following are conclusions drawn from this project:

1. The GWPC State Survey results of 29 primacy states and 8 EPA regions with 6 direct implementation states demonstrate that all E&P wastes are eligible for Class IID injection in most Section 1425 states. Eighty-seven percent of the Class IID injection wells nationwide are presently used to dispose of all E&P wastes. Sixty-one percent are used to dispose of E&P wastes mixed with non-hazardous non-exempt wastes.
2. A past Regulatory Review accurately forecasts the final GWPC State Survey results before the survey was implemented. It was expected that the State Survey results would show that most Section 1425 primacy states allowed the injection of all E&P wastes into Class IID wells.
3. Nationwide Waste Surveys conducted in 1985 and 1995 by API show that E&P wastes were injected into Class IID wells routinely. As regards E&P associated wastes, it was reported in 1995 that 477,000 barrels of tank bottoms, 7,700 barrels of dehydration wastes, 1,183,000 barrels of completion wastes and 5,621,000 barrels of workover wastes were injected into Class IID wells.
4. E&P wastes exempted from Subtitle C under RCRA and E&P wastes eligible for injection into Class IID wells under SDWA were both recognized by Congress as the same wastes being regulated under both Acts. The law firm, McGuire, Woods, Battle and Boothe(1), documented this fact in their report to API regarding litigation on RCRA. In addition, scrubber liquids and boiler blowndown waters were not listed in the 1988 Regulatory Determination(7) as E&P wastes, but were later included by the Office of Solid Waste after the Office of Drinking Water approved these waters for Class IID injection.
5. The Office of Drinking Water has used RCRA language on several occasions to define eligible fluids for injection. The last time fluids eligibility came into question was in 1987 for air scrubber and water softener regeneration brines in California. In that regard, EPA used the phrases <u>integral part</u>, <u>integrally associated</u> and <u>integrally related</u> to approve injection of these fluids into Class IID wells. These type phrases were also used to assist in defining RCRA E&P wastes.

6. A Federal Advisory Committee was formed in 1991-92 to implement changes recommended by a 1988-89 Midcourse Evaluation UIC Committee made up of state and federal agencies; the fluids eligible for injection into Class IID wells were never considered an issue in either one of these efforts.
7. EPA Region VI has always known that E&P wastes were being injected into Class IID wells since inception of the UIC programs in 1982.[29] Sixty-one percent of the Class IID injection wells nationwide are presently used in Region VI to dispose of E&P wastes.
8. By restricting the flexibility and discretion of the State Directors to determine fluids eligible for disposal into Class IID wells, the EPA UIC Technical Workgroup's draft document would negatively affect large numbers of injection wells and the oil and gas production associated with them.

A 2000 Regulatory Review Addressing Fluids Eligible For Class IID Injection

Introduction

The types of fluids eligible for injection into Class II wells were first defined in the June 24, 1980 regulations issued by the Environmental Protection Agency (EPA) under the authority of the Safe Drinking Water Act (SDWA) of 1974. However, EPA was challenged by industry and the states in 1981, after the Act was amended in 1980, because the definition did not allow for the injection of other waste fluids that were an integral part of the production of oil and gas fields. The amended Act defined the types of fluids eligible for injection into Class II disposal wells, but not for Class II enhanced recovery wells. For disposal wells, the Act generally addressed eligible fluids as: "brine or other fluids which are brought to the surface in connection with oil or natural gas production or natural gas storage operations."

In the meantime, the Resource Conservation and Recovery Act (RCRA) was amended October 31, 1980, to require an EPA study addressing drilling fluids, produced water and other wastes associated with the exploration and production of crude oil or natural gas. EPA was required to determine if these oil and gas wastes should be subject to Subtitle C of the hazardous waste regulations. The term "other wastes associated" specifically included waste materials intrinsically derived from primary field operations associated with the exploration and production of crude oil and natural gas. The Office of Solid Waste generally determined that if the waste was brought to the surface during oil and gas operations or otherwise had been generated by contact with the oil and gas stream, it would most likely be considered an exploration and production waste.

The wastes identified under the SDWA and RCRA are very similar and did not appear to create a serious conflict even when the industry and states challenged the EPA underground injection control (UIC) regulations in 1981. The industry believed that natural gas plant wastewaters should be injected into Class IID wells, but these waters were not included in the regulations. These contested fluids were for the most part blowdown waters from cooling tower and boiler operations, but were not produced from oil and gas wells. EPA later approved the injection of these wastewaters because they were considered an "integral part of the production of oil and gas fields". The Agency copied this language from the industry and state's comments during the litigation of this regulation. The industry had stated that these fluids should be eligible for injection, because the waste fluids were generated from operations that were an "integral part of the production of oil and gas fields". The "integral part" phrase came from the industry arguments used to justify the amendment of RCRA in 1980. Further, this type language was included in the Congressional Record of the 1980 Amendments, but there the phrase was labeled as "intrinsically derived".

Until 1992, it appeared that the definition of fluids eligible for Class IID injection was collectively understood by the EPA, states and industry. The last time fluids eligibility had come into question was in 1987 for air scrubber and water softener regeneration brines in California. In that effort, EPA used the phrases "integral part", "integrally associated" and "integrally related" to approve injection of these fluids into Class IID wells. After 1992, however, the fluids eligibility issue became a somewhat contentious issue. In 1997 it became serious. The reasons the issue became contentious is discussed under the Safe Drinking Water Act (Section B). As a result of this important issue, the following 1999 Ground Water Protection Council (GWPC) regulatory review and state survey were implemented to determine if eligible fluids for injection into Class IID wells could be reasonably interpreted.

Regulatory Review
Oil and gas production wastes are predominately regulated under authority of two Statutes – the Resource Conservation and Recovery Act and the Safe Drinking Water Act. As a result, the wastes in one regulatory program are known to be the same wastes in another regulatory program under these Acts. During the litigation of RCRA production wastes in 1986, the law firm Mcguire, Woods, Battle and Boothe pointed out: "To place the production wastes in context; it is well known that the unique nature of the materials generated by the petroleum industry was recognized in several special provisions enacted in other environmental statutes in 1980:

1. The Safe Drinking Water Act Amendments, Pub. L. No. 96-502, 94 Stat. 2737 added Section 1425, which provided for optional use by States of their own regulations for oil and gas underground injection in lieu of extensive EPA regulations. (Even under Section 1425, some modification to regulations occurred to accommodate MITs, AOR and inclusion of wastes other than oil field brine.)

2. The Used Oil Recycling Act of 1980 Pub. L. No. 96-463, 94 Stat. 2055; and

3. The Comprehensive Environmental Response, Compensation, and Liability Act of 1980, Pub. L. No. 96-510, 94 Stat. 2767, contained definitional exclusions for petroleum and natural gas relating to what constituted a "hazardous substance" in Section 101(14) and a "pollutant or contaminant" in Section 104 (a)(2).'[(1)]

Consequently, this regulatory review addresses both RCRA and SDWA to assess the meaning of eligible fluids for injection into Class IID wells.

Resource Conservation and Recovery Act (RCRA) – 1976
Congress passed RCRA[(2)] to regulate the disposal of solid wastes, and President Ford signed the Act into law October 31, 1976. RCRA is designed to provide "cradle-to-grave" controls by applying management requirements on generators and transporters of hazardous wastes and upon the owners and operators of treatment, storage and disposal facilities. Since the passage of RCRA, Congress, the courts, and the regulated community, have engaged in an almost continuous debate over the threshold issue of what materials should be regulated as hazardous wastes under Subtitle C. The materials that were lumped together in the "special wastes" category in 1976 have presented particular difficulties for the Agency, although specifically identified by Congress as wastes for which Subtitle C regulation was not appropriate.

EPA first addressed the problem posed by "high-volume, relatively low risk waste categories", such as oil and gas drilling fluids, in regulations proposed in December 1978.[(3)] The Agency announced its intention for regulating such wastes, but deferred new requirements until further study had been completed. The regulatory proposal caused Congress to again assess the impacts of the 1976 Act and decide how to address these particular wastes.

RCRA Amendments of 1980

Congress established a statutory restriction on the regulation of oil and gas exploration and production wastes by including what is commonly known as the "production wastes exemption" in the Solid Waste Disposal Act Amendments of 1980. President Carter signed the Act into law on October 21, 1980. Congress thereby rescinded the power granted EPA in 1976 to regulate, as hazardous wastes under Subtitle C, oil, gas and geothermal energy "production wastes". Section 7 of the 1980 RCRA Amendments amended RCRA Section 3001 (b) to exclude production wastes from the hazardous waste regulations then being developed. This exclusion was to last until EPA had completed a study and made a determination (after public hearing and opportunity for comment) whether or not regulations under Subtitle C were justified. EPA would then be required to transmit its regulatory determination, along with any necessary regulations, to Congress. Further, any such regulations could not take effect unless authorized by Act of Congress. EPA was required under the Act to complete the study within two years of enactment.

The production wastes included drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy. The term "other wastes associated" was specifically included to designate waste materials intrinsically derived from the primary field operations.[3] It would cover such substances as: "Hydrocarbon bearing soil in and around the related facilities; drill cuttings; materials (such as hydrocarbon, water, sand and emulsion) produced from a well in conjunction with crude oil, natural gas or geothermal energy; and the accumulated material (such as hydrocarbon, water, sand and emulsion) from production separators, fluid treating vessels, and production impoundments".[3]

Regulatory Determination Study

EPA began the Congressionally mandated study six years later starting in 1986, but only after the Alaska Center for the Environment filed a citizen suit in 1985. The study was to determine if regulations were warranted under Subtitle C for production wastes. A Consent Order was entered on June 30, 1986, and modified on April 23, 1987. Under the Consent Order as modified, the Agency was required to complete the research and study and to submit the RCRA Section 8002(m) report to Congress by December 31, 1987. The regulatory determination, after public hearings and opportunity to comment, was to require new regulations under Subtitle C of RCRA or to demonstrate that such regulations were unnecessary.

During the RCRA study, the American Petroleum Institute (API) worked with the EPA Office of Solid Waste to provide information on the industry's operations and the wastes volumes it generated. API conducted a survey to determine the volumes of drilling fluids, produced water and associated wastes uniquely derived from exploration and production operations. This detailed report [5] was completed in October 1987 and shared with the

Agency. EPA, in its 1987 Report to Congress and 1988 Regulatory Determination, used the production wastes volumes estimated in the API Report.

In December 1987, EPA completed its Report to Congress on the Management of Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy.(6) This was a detailed report that included the volumes and types of wastes since 1985, how the wastes were managed, any damages and potential risks, and numerous other effects and impacts.

On July 6, 1988, the EPA Administrator made a Regulatory Determination that oil and gas exploration and production (E&P) wastes should not be regulated under Subtitle C of RCRA.(7) The Agency concluded that the wastes would be better controlled through improvements to existing state and federal regulatory programs. Besides drilling fluids and produced water identified as E&P wastes, there were other wastes associated with the exploration, development, and production of crude oil or natural gas. EPA designated these other wastes as "associated wastes". A relatively new updated list appears in Table ES-1 of EPA's January 2000 Associated Wastes Reports.(8) The E&P waste lists have been modified on several occasions with Table ES-1 being the most up-to-date change. ES-1 does identify additional wastes.

In 1988, P.G. Wakim updated the 1985 API Survey information for associated wastes.(9) This refinement included the waste disposal methods used for each associated waste. The updated report showed that 775,000 barrels of associated wastes were nearly all injected into Class IID wells in 1985. Eight thousand barrels of used oils, 46,000 barrels of untreatable emulsions, 6,000 barrels of produced sand, 406,000 barrels of dehydrator and sweetening unit wastes, 70,000 barrels of cooling tower blowdown, and 238,000 barrels of other wastes (including wastes not listed on the survey form such as contaminated fluids) were injected into Class IID wells. This June 1988 report was provided to EPA for use in their efforts to improve state and federal programs. Three EPA Direct Implementation and 15 Primacy State UIC Programs allowed Class IID injection of these E&P wastes.

EPA Office of Solid Waste Clarification on Production Wastes

On March 22, 1993, the EPA Office of Solid Waste again clarified the scope of the E&P exemption with respect to wastes generated by crude oil reclamation operations, service companies, crude oil pipelines, gas plants and feeder pipelines, and natural gas storage fields.(10) This clarification discussed mixing non-hazardous, non-exempt wastes with exempt E&P wastes and explained why the resultant wastes remained exempt.
In May 1995, EPA published the "brown booklet"(11) to provide information on the scope of the E&P wastes exemption, to determine the regulatory status of E&P wastes, and to provide examples of non-exempt and exempt wastes. EPA explains in the booklet that "according to the legislative history, the term 'other wastes associated' specifically includes waste materials intrinsically derived from field operations associated with the exploration, development, or production of crude oil and natural gas". The Agency offers a "rule-of-thumb" guide to determine if an E&P waste is exempt or non-exempt from RCRA Subtitle C regulations:

- Has the waste come from down-hole, i.e. was it brought to the surface during oil and gas E&P operations?

- Has the waste otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product?

If the answer to either question is yes, then EPA feels the waste is most likely considered exempt from RCRA Subtitle C regulations. However, there are E&P wastes not clearly defined by this rule-of-thumb, i.e. mixture of exempt wastes with non-exempt non-hazardous wastes; the resultant mixture remains exempt from Subtitle C. This booklet is available from the Office of Solid Wastes but is presently being updated. (June 2001)

In EPA's UIC regulation, 40 CFR 146.5, the fluids considered eligible for injection into Class IID wells are those fluids "which are brought to the surface in connection with conventional oil or natural gas production which may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as hazardous wastes at the time of injection". It should be noted here that this definition of eligible fluids was finalized in 1982 after industry and state litigation, but before the Regulatory Determination. The Final 1982 regulation determined that certain wastewaters from gas plants are identified as E&P wastes. As a result, the definition under Section 146.5 is now outdated, since the testing of wastewaters from gas plants that are an integral part of production operations is not required under RCRA. Further, the UIC regulatory definition for fluids eligible for injection appears to be generally the same definition for E&P wastes identified by EPA's rule-of-thumb above.

As shown in the 1985 Part II API waste survey, wastes were injected into Class IID wells that satisfy both EPA's rule-of-thumb under RCRA and the definition of fluids eligible for Class IID injection under the SDWA. Subsequently, the States and the Agency agreed on the type of fluids eligible for injection, without controversy, for nearly 10 years. For example, in 1993 EPA Region VI responded to a letter from the Louisiana Office of Conservation (OC) stating that E&P wastes under the new guidance would be eligible for injection into Class IID wells.[12] The Louisiana OC and other Region VI states interpreted the letter from Region VI as official approval for the injection of E&P wastes into Class IID wells, and they also understood the letter addressed Region VI only and not other regions.

API 1995 Survey on Production Wastes

In June 2000, API completed a survey of E&P drilling fluids, produced water and associated wastes volumes for the year 1995.[13] The Industry felt it was necessary to update the 1985 survey to again determine E&P waste volumes and to again assess waste management practices utilized by the industry. The API survey of drilling operations, production facilities and gas plants showed that waste volumes were reduced and management practices substantially improved. It is noted in the Executive Summary that 90.8% of all E&P wastes and produced water was injected into Class IID and Class IIR wells. The total volume injected consisted of 16,400 million barrels of produced water, 19.3 million barrels of drilling fluids, and 7.8 million barrels of associated wastes.

In regard to associated wastes, it was reported that 477,000 barrels of tank bottoms, 7,700 barrels of dehydration wastes, 1,183,000 barrels of completion wastes and 5,621,000 barrels of workover waste were injected into Class IID wells. It should be noted that the titles of each wastes, such as "workover and completion wastes", have different types of wastes listed under these broad titles as shown in Table ES-1 of the associated waste reports. For example, Tank Bottoms has listed under its title: solids, sands, emulsions, and accumulated heavy hydrocarbons. Consequently, numerous associated waste types under these four waste classifications were injected into Class IID wells in 1995. The API Report also found that numerous states approved Class IID disposal of these fluids. The study showed that 33% of the states that reported Class II disposal of these wastes were Direct Implementation states and that 67% of the states had obtained Primacy under Section 1425. The 1995 API waste survey showed that the Class IID injection of various E&P wastes was an accepted practice and was apparently not an issue at this time.

In Montana, as recently as 1996, Region VIII approved the Class IID injection of various E&P wastes, which are basically identical to those listed in the 2000 API Survey. Montana included in their 1995 UIC Class II Primacy Application to Region VIII the proposed list of E&P wastes they felt should be approved for injection into Class IID wells. Montana obtained Class II primacy under Section 1425 from EPA Region VIII on November 19, 1996. Upon approval of Primacy, they began to allow Class IID injection of E&P wastes listed in their state regulation. The E&P waste types are listed in the Administrative Rules of Montana - 36.22.1401(4)(g), which became effective May 10, 1996. They are: produced water, drilling fluids, drill cuttings, rigwash, well completion fluids, workover fluids, gas plant dehydration wastes, gas plant sweetening wastes, spent filters and backwash, packing fluids, produced sand, production tank bottoms, gathering line pigging wastes, hydrocarbon-bearing soil, and waste crude oil from primary field sites. This approved list includes E&P wastes that were not "brought to the surface" from oil and gas producing wells, and it shows that E&P wastes generated by contact with the oil and gas producing stream during the removal of produced water or other contaminants were also considered as eligible fluids by Region VIII.

Safe Drinking Water Act (SDWA) – 1974

The SDWA was passed by Congress and signed into law by President Ford on December 16, 1974.[14] The development of the current UIC regulatory program has been affected not only by a number of statutory changes since that time, but also by numerous interrelated regulatory proposals, re-proposals and promulgations, some influenced by state and industry challenges and negotiations. The statutory history regarding oil and gas-related injection wells (Class II) is clear, and the Congressional intent in enacting the SDWA of 1974 is also clear when reviewing the House Report accompanying the original SDWA and the subsequent amendments. In the original SDWA, Part C, Section 1421, the Statute says that EPA may not prescribe requirements for state programs which "interfere with or impede" oil and gas related underground injection (disposal or enhanced recovery) unless such requirements are "essential" to assure that underground sources of drinking water will not be endangered by such injection. Many state regulators felt this language was very close to a Class II injection well exemption from a federal program, because Congress stated in House and Senate floor debates that states had the expertise and were doing a good job in administering their current oil and gas related injection well programs.

Nevertheless, EPA did propose regulations in 1976 that were different from the language in Section 1421; consequently, Congress amended the SDWA in 1977 to give EPA direction in drafting regulations that would give the states more flexibility in administering an approvable UIC program. In the 1977 amendments [(15)], Congress added two new provisions relating to oil and gas related injection wells: 1) new language was added to Section 1421 directing the EPA in its regulations for state programs to "permit or provide for consideration of varying geologic, hydrological, or historic conditions in different states;" and 2) new language was added to Section 1421 to require the EPA to avoid "to the extent possible", regulatory requirements "which would unnecessarily disrupt state underground injection control programs which are in effect and being enforced in a substantial number of states." The EPA responded to the Congressional mandate and promulgated UIC regulations in mid-1980[(16-1)(16-2)] that states and industry both believed would have severely constrained the domestic oil and natural gas industry and severely disrupted state programs without resulting in any added environmental protection.

Gas Plant Fluids, January 1979 – February 1982

In the meantime, fluids eligible for injection into Class II wells were addressed early in the formulation of federal UIC regulations under the SDWA passed in 1974. EPA first proposed regulations in 1976,[(17)] but the states testified that they did not adequately address UIC operations already in existence in many states.

After regulatory proposals were issued in 1979[(18)], EPA listed fluids in the June 24, 1980 final regulations that could be injected into Class II wells. Section 146.5. (b) stated Class II wells are "Wells, which inject fluids:

(1) That are brought to the surface in connection with conventional oil or natural gas production;

(2) For enhanced recovery of oil or natural gas production; and

(3) For storage of hydrocarbons which are liquid at standard temperature and pressure."

A number of those commenting on the 1979 regulatory proposal suggested that disposal wells handling blowdown water discharges from gas plants and similar wastes be treated not as Class I but as Class IID fluids. EPA stated "given the nature of these operations and the chemical composition of the injection fluids, the Agency has decided that these operations would be more appropriately regulated under Class I".[(16.2)]

In 1981, a number of trade organizations, oil and gas producers, and the State of Texas petitioned the court for a review of the 1980 final regulations. In particular, these parties wanted to "broaden Class II to include wells in which waste waters from gas plants, which are an integral part of the production of gas from oil and gas fields, are injected along with produced brines, so long as these waste waters are not a hazardous waste at the time of injection".[19] Industry pointed out to EPA that it was fairly common to dispose of blowdown waters from cooling towers and boilers used in the natural gas plants, along with produced water separated from the natural gas. As a result EPA decided, "Adding this blowdown water, which generally contains low total dissolved solids (TDS) levels to the brine, would not increase risk to USDW's".[19] After settlement negotiations, the Agency believed it was reasonable to reduce the administrative burden for the states and the industry, which would otherwise result from requiring a separate Class I permit for these wells.

The 1980 Final regulation was amended on February 3, 1982.[20] It allowed the above waste fluids to be eligible for injection into Class IID wells under Section 146.5 (b) as follows:

> "Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with wastewaters from gas plants, which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection."

This flexibility allowed states to expand the types of fluids eligible for injection into Class IID wells. The waste fluids could be injected if they were an "integral part of production operations", and they did not necessarily have to be "brought to the surface" from oil and gas wells as worded in the final 1980 regulations. In July 1988, cooling tower and boiler blowdown waters were determined to be exempt from Subtitle C by the EPA Office of Solid Waste upon issuing their Regulatory Determination on Exploration and Production (E&P) wastes generated within oil and gas fields.[7] Since it was determined by the EPA Office of Drinking Water that these natural gas plant wastewaters are eligible for injection into Class IID wells, they should now not have to be tested at the wellhead for their hazardous characteristics. The UIC regulation was written prior to the Regulatory Determination and should be amended to eliminate the RCRA testing of gas plant wastewaters eligible for Class IID injection.

Safe Drinking Water Act (SDWA) Amendments of 1980

Shortly after the 1977 amendments of the SDWA were signed into law, the Congress began hearings and debates and drafting legislation to once again amend Part C of the SDWA. President Carter signed the SDWA 1980 amendments into law on December 5, 1980. [21] The main thrust of these amendments was to provide further flexibility to the states in obtaining primacy for Class II oil and gas UIC programs. The amendments added a new Section 1425 which provided that in order to obtain primacy approval for its

Class II UIC program, a state need only demonstrate that the program meets the four specific statutory requirements of Section 1421 and represents an "effective program" to prevent underground injection which endangers USDW's – and that it need not meet the EPA's minimum requirement regulations. The House Report accompanying the 1980 SDWA Amendments [(22)] indicated that it was the intent of the Committee that the states should be able to continue their programs unencumbered with additional Federal requirements, if they could demonstrate that they met the requirements of the Act as amended through Section 1425.

EPA approved state UIC primacy programs under Section 1425 beginning in 1982. Most, if not all, primacy applications were approved with the understanding that exploration and production waste could be injected into Class II disposal wells. Twenty-four States obtained approval from EPA for Class II primacy under Section 1425, whereby the Act did not require these states to mirror the EPA Class II regulations. Nearly all of these 1425 states obtained primacy in the early to mid-80's. They signed primacy agreements that are different in many features, including what fluids could be injected into Class IID wells. The present UIC Class II program is now implemented directly by EPA under Section 1422 in 7 states plus Indian Lands (Arizona, Florida, Kentucky, Michigan, New York, Pennsylvania and Tennessee).

Scrubber Liquids and Regeneration Brines, January 1985 – July 1987

In 1985, EPA Region IX was using the following policy[(23)] for injecting water softener regeneration brines and air scrubber wastes at oil and gas fields in California:

(1) Wells which inject water softener regeneration brine or air scrubber waste are not Class II wells, unless injection is for enhanced recovery, in which case the wells are Class II wells.

(2) Wells which inject water softener regeneration brine or air scrubber waste commingled with other fluids (e.g. produced water or filter backwash) are not Class II wells, unless injection is for enhanced recovery, in which case the wells are Class II wells.

By February 1987, Region IX had issued 19 Class I permits and one Class V permit for facilities that injected either one or both of these wastes. Region IX's inventory also showed that 16 Class V wells injected fluids containing air scrubber wastes, and 41 Class V wells injected fluids containing water softener regeneration brine with most still to be permitted.

The California Department of Oil and Gas and Geothermal Resources (CDOGGR) and The Western Oil and Gas Association (WOGA) began working with Region IX in 1985 on the reclassification of wells injecting non-hazardous fluids integrally related to oil and natural gas operations. A description of the non-hazardous fluids being injected into Class I and Class V wells follows:

(1) Water Softener Regeneration Brine – This is a waste fluid with high concentrations of TDS, especially calcium, magnesium, and chloride. In general, passing it through a

resin, which replaces calcium and magnesium ions in the water with sodium ions, softens produced water, surface water or fresh water. Periodically, the resin in the water softener unit is regenerated with concentrated solutions of sodium chloride, which replaces the calcium and magnesium ions captured on the resin with sodium ions in the solution, yielding water softener regeneration brine. Water softener regeneration brines can exceed 100,000 mg/l TDS, and have elevated levels of metallic cations, such as lead and mercury.

(2) Air Scrubber Waste - This waste fluid is sulfur dioxide (SO2) scrubber blowdown (also commonly known as scrubber liquor) with high concentrations of total dissolved solids (much greater than 10,000 ppm). In general, crude oil is burned for power to produce steam, which is injected to enhance the recovery of extremely heavy crude oil. Air scrubbers are required when the crude oil is burned, because Kern County, CA is a Non-Attainment Area for air quality with respect to S02. Air scrubber wastes are very high in TDS levels (up to 50,000 ppm) and can exceed drinking water standards for selenium, arsenic, silver, and lead.

After CDOGGR and WOGA completed negotiations with EPA-Region IX and EPA-Washington, a decision was made to allow water softener regeneration brine and air scrubber waste to be injected into Class IID wells. The Class I and V permits were rescinded by Region IX and Class IID permits were issued by the CDOGGR who administers the Class II program. A Policy Letter(24) was issued July 31, 1987, from Mr. Michael B. Cook, Director, Office of Drinking Water for these type operations.

The final policy, which was sent to all Regions and applied nationwide, read as follows:

"Aside from enhanced recovery operations, 4 kinds of fluids, as noted below, may be injected into Class II wells.

1. Waste waters (regardless of their source) from gas plants, which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection (40 CFR 144.6 (b) (1)).

2. Brines or other fluids brought to the surface in connection with oil or natural gas production or natural gas storage operations (40 CFR 144.6 (b) (1)).

3. Brines or other fluids described in Item 2 which, prior to injection, have been:

(a) Used on-site for purposes integrally associated to oil and gas production storage, or

(b) Chemically treated or altered to the extent necessary to make them useable for purposes integrally related to oil and gas production or storage, or

(c) Commingled with fluid wastes resulting from the treatment in (b), so long as they do not constitute a hazardous waste under 40 CFR Part 261.

4. Fresh water (i.e. water containing less than 10,000 mg/l total dissolved solids) from ground water or surface water sources, added to or substituted for the brine may also be injected, as long as the only use of the water is for purposes integrally associated with oil and gas production or storage."

Item 1. above was clarified to ensure water softener regeneration brine in natural gas plants was approved for Class IID injection. This was clarified by including the wording "regardless of their source" in the parenthesis.

The flexibility used for gas plant wastewaters was extended to air scrubber wastes and water softener regeneration brines at oil and gas production facilities in California. The fluids could be injected into Class IID wells if they were "integrally associated or related" with oil and gas production or storage. These natural gas plant wastewaters were later exempted from Subtitle C under the July 1988 Regulatory Determination. These wastewaters were approved for injection into Class IID wells, although they were not "brought to the surface" in connection with oil and gas well production. Most importantly, it shows that certain E&P wastes generated by contact with the oil and gas producing stream during the removal of produced water or other contaminants were also included as eligible fluids.

Midcourse Evaluation – 1988-1992

In January 1988, the EPA Office of Drinking Water (ODW) initiated a review of the adequacy of the existing regulations for Class II injection wells. This effort, known as the Mid-Course Evaluation (MCE) effort, focused on a wide spectrum of technical and policy issues related to the Class II injection well program.

"ODW initiated the MCE of the Class II program for 3 main reasons. First, it was necessary to make sure the program appropriately reflects the experience and insight the agency has gained since the UIC regulations were published 9 years ago. Second, because of the nature of the data available to EPA- Headquarters regarding Primacy State programs, it was necessary to review these programs to determine the adequacy of USDW protection. Third, EPA's recent Report to Congress and Regulatory Determination on oil and gas production waste identified differences in state implementation and enforcement in Class II UIC programs and recommended improvements in these areas". [25]

The MCE process to determine areas of concern in the program took approximately 2 years. In that 2 year period, ODW identified 5 major areas of potential concern for the study:

(1) Operating, monitoring, and reporting requirements;
(2) Plugging and abandonment;
(3) Area of review and corrective action requirements;
(4) Mechanical integrity testing requirements; and
(5) Casing and cementing (i.e., construction) requirements.

The MCE study concluded in August 1989 and recommended the following: "Based on the conclusions developed from the MCE effort, the MCE Workgroup recommends the following changes to the Class II program. Several of these changes involve only minor modifications or clarifications, and some have already been initiated:

- Strengthen requirements pertaining to the surface operating practices for commercial Class II disposal wells.
- Add 2 special provisions for temporarily abandoned (TA'd) injection wells;
- Revise existing forms used to report key information;
- Revise requirements concerning the use of annular pressure monitoring;
- Revise regulations to disallow injection pressure/injection rate monitoring as a means of demonstrating mechanical integrity for new wells;
- Develop the general framework for a decision tree (i.e., a logical decision process) for assessing actions pursuant to failure of an MIT;
- Highlight the fact that more than one log may be required to demonstrate mechanical integrity on a case-by-case basis;
- Clarify, using regulations or guidance, what types of inter-Formational fluid movement are prohibited".

The issue addressing fluids eligible for injection into Class IID wells was never discussed in the MCE, thus was not considered a problem in 1988-89.

Federal Advisory Committee - 1991-1992

At the spring meeting of the Ground Water Protection Council in Point Clear, Alabama, in 1991, the EPA Office of Ground Water and Drinking Water (OGWDW) and the states agreed to form a Federal Advisory Committee to address the MCE recommended changes. The committee members included state directors from Texas, California, Kansas and Ohio; environmental representatives from the Friends of the Earth, Audubon Society and Subra Consulting Company; federal officials from EPA, the Department of Energy and the Minerals Management Service; and oil and gas industry representatives from API, Arco, Conoco and the Independent Petroleum Association of America (IPAA).

Specifically, 3 EPA Guidance's – "Follow-up to Class II Well MIT failures under Section 40 CFR 146.8"; "Operating, Monitoring, and Reporting Requirements for Class IID Commercial Salt Water Disposal Wells"; and "Management and Monitoring Requirements for Class II Wells in Temporary Abandoned Status" --- were developed by the FAC for use by the EPA Regions. In addition, the Committee developed recommendations for changes in the following areas of the UIC regulations: construction, monitoring and testing, and area-of-review requirements. The Guidances and "Recommendations"(26) were agreed to and endorsed by all committee members by midyear 1992, with the exception of Ohio and IPAA whom did not endorse Provision #11 of the Recommendations. Provision #11 required annual MIT's on injection wells with only one layer of protection.

EPA developed draft regulatory changes that addressed the recommendations of the FAC in 1992. However, a regulatory proposal was never issued due to disagreements within EPA. Most importantly during the FAC meetings, the subject of fluids eligible for Class IID injection was never discussed. At this time, State Primacy and DI states were allowing the injection of exempt E&P wastes without any regulatory concerns.

Defining Class II Injection Fluids – 1992-1996

Until late 1992, there was a general understanding by states that all E&P exempt wastes could be injected into Class IID wells. The issue arose about E&P exempt wastes injection during investigation of a Cabinet Member candidate of the Clinton Administration. During the investigation of the Cabinet Member's financial holdings, an EPA Region VI inspection was conducted at a non-hazardous oilfield waste (NOW) facility located in Louisiana in which the candidate had financial interests.

As a result of the inspection, Region VI stated in a "draft" letter [27] to the Louisiana Office of Conservation (OC) dated January 8, 1993, that "A recent inspection of Class II commercial facilities has raised concern that there may be some confusion among Primacy State Underground Injection Control (UIC) Programs regarding non-hazardous oilfield wastes (NOW) and acceptable Class II disposal well waste streams". The draft letter went on and explained that since E&P wastes have been exempted from Subtitle C of RCRA, "some states may have considered certain NOW wastes eligible for injection into Class II disposal wells which do not qualify as a Class II waste stream". Further, it stated that EPA regulation identifies Class II waste streams as those "which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production, and may be commingled with gas plant waste waters". EPA through this draft letter was giving Louisiana time to respond to what it thought may be a problem in their UIC primacy program.

In a faxed memorandum to the Louisiana OC dated January 21, 1993[28], EPA notified UIC staff that "Wastes accepted at Class II well sites would be a major topic of discussion at the 1993 State/EPA meeting scheduled for late February". It also declared "We understand the Region VI UIC State Programs generally allow disposal of RCRA exempted NOW wastes via injection down Class II wells". Region VI asked the State to identify which NOW wastes they believed should be allowed for Class II injection. Region VI also furnished to the OC a list of exempt and non-exempt wastes formulated by the EPA Office of Solid Waste in the Regulatory Determination, July 1988. The Agency felt the list would give the Louisiana OC an idea of what was generally acceptable for injection into Class IID wells, which would work toward "flexibility" by means of new Federal UIC Guidance.

On February 3, 1993, the OC responded to EPA's January 1993 draft letter and fax [29]. The OC informed the Agency that their UIC Program was approved on April 23, 1983.

They continued: "Many of the E&P wastes, which have been exempted from the hazardous waste requirements of the Resource Conservation and Recovery Act since 1980, have been disposed of in these commercial wells for at least 12 years". In their letter they also said: "The 29B definition of non-hazardous oilfield wastes (NOW) is similar to the list of exempt wastes in the Report to Congress. The disposal of these exempt E&P wastes in Class II disposal wells has been occurring for quite some time, with EPA having full knowledge of this activity". They went on to say that in checking with other states in the Region those states also allowed the disposal of such wastes in commercial Class IID disposal wells. The OC requested EPA not make a decision on this important issue until a meeting could be held to discuss the matter in greater detail.

Draft Guidance dated March 17, 1993, from James R. Elder, Director, Office of Ground Water and Drinking Water to Regions II-X,[(30)] was developed by EPA-Washington and clarified which waste fluids generated by the oil and gas exploration and production industry could be injected into Class IID wells. The Draft Guidance stated: "The key concepts that have been used by the UIC program to determine whether waste fluids could be injected in Class II wells were that they had to be non-hazardous and integrally associated with oil and gas production. Under RCRA the Agency has defined a series of wastes, which are non-hazardous because they are uniquely associated with oil and gas exploration and production. This Office followed closely the development of the E&P policy to ensure that the UIC regulatory scheme would not be unnecessarily disrupted. Similarly we believe that <u>all</u> exempt E&P wastes under RCRA can be injected in Class II wells as long as their physical state allows it."

The Draft Guidance was completed and sent March 19, 1993, for comment to all the EPA Regions with a copy sent to the Louisiana OC.[(31)] The letter transmitting the Guidance stated: "We believe that this guidance reflects our discussions at the recent section chiefs meeting."

Region VI reviewed this Draft Guidance and responded to the Louisiana OC. In a letter dated April 20, 1993, from Mr. Myron O. Knudson, Director, Water Management Division to Mr. H.W. Thomson, Commissioner, Louisiana Office of Conservation. [(32)] Mr. Knudson stated; "Under the new guidance, <u>all</u> exploration and production (E&P) wastes exempted under Section 3001(b)(2)(A) of the Resource Conservation and Recovery Act (RCRA) will be eligible for injection into Class II disposal wells". In addition, the Agency sent a copy of a 1993 Federal Register Clarification [(33)] to show that "wastes derived from the treatment of an exempted wastes generally remains exempt, and that off-site transportation does not negate the exemption." The concern of commingling tank truck washout waters, rainwater, or pipeline test water was addressed by the EPA Office of Solid Waste and Mr. Knudson felt the issue was resolved. This not only settled the problem for Louisiana, but also for the remaining states in Region VI who were injecting E&P wastes into Class IID wells.

The Louisiana OC thought the problem was resolved after receiving the letter from Mr. Knudson of Region VI. The letter inferred that E&P wastes would be approved for injection into Class IID wells through the new Guidance, but it did not say that future correspondence would be necessary to tell OC when the Guidance would be effective. In fact, it was felt that Region VI had officially approved the injection of all E&P wastes since no reply or communication in the future was requested. As far as the OC was concerned, the UIC program was in compliance with the Primacy Agreement approved in 1982, since no further action was forthcoming.

Apparently, as discussed above, the Louisiana OC thought the letter from Region VI meant official approval for injecting all E&P wastes into Class IID wells. This conclusion can be interpreted in a letter [34] from the OC to Shell Oil Company dated May 3, 1993. The OC informed Shell that "EPA has made a determination that all exploration and production (E&P) waste exempted under Section 3001 (B) (2) (A) of the Resource Conservation and Recovery Act (RCRA) will be eligible for injection into Class II disposal wells. Therefore, EPA's response resolves this issue." Not only Shell, but also the Industry and Region VI states, interpreted the April 1993 letter as official guidance for allowing the injection of all E&P wastes into Class IID wells in Region VI.

On March 21, 1994, EPA-Washington sent a letter to the Region UIC Section Chiefs (Regions I-X) concerning RCRA exempt wastes allowed for disposal into Class II UIC wells.[35] The 1993 draft guidance had been delayed due to discussions with the Office of Solid Waste on certain issues. Although it was felt by the states and industry in Region VI that these wastes had already been officially approved for injection, they felt the Guidance was being issued to ensure that all Class II UIC programs nationwide would benefit. The letter told the UIC Section Chiefs that final UIC guidance related to the injection of E&P wastes was being completed. It also stated "A comment summary from all the Regions and the affected primacy states is attached. Below each comment is an attempt to incorporate comments, clarify the issue, or defer any action on a particular topic". The goal by EPA Headquarters was to have the UIC guidance completed prior to their scheduled UIC Section Chief's meeting in April 1994 so that it would be available to all commenters for review. At this point in time, for unknown reasons, the Guidance was not issued; however, there was no communication to the states on the reason why.

In 1996, the GWPC met in Houston, Texas, on issues concerning the UIC programs across all classes of injection wells. In that meeting the Class II Division decided to request a resolution [36] from the GWPC Board to EPA Headquarters asking that the 1993 Region VI official Guidance allowing all E&P wastes injection into Class IID wells be approved for all Regions to provide consistency. The resolution states that GWPC felt Region VI had issued an official Guidance on E&P wastes injection. The resolution states: "Whereas on April 20, 1993, the USEPA Region VI Water Management Division issued a clarification letter to the Louisiana Office of Conservation stating that all E&P wastes exempted under Section 3001(b)(2)(A) of RCRA are eligible for injection into Class II disposal wells, because said wastes are RCRA Subtitle C exempt and uniquely associated with OGE&P operations". The resolution finished by requesting that EPA "issue an updated Guidance in calendar year 1996 to Regions 1-10". This resolution was presented at the spring GWPC 1996 meeting in Alexandria, Virginia, in the Class II Division meeting and then adopted by the GWPC Board the next day for submission to EPA-Washington. However, EPA Washington still did not choose to issue the updated Guidance.

On June 26, 1996, EPA-Washington responded to the resolution submitted by GWPC. (37) The Agency stated in their letter to GWPC that the determining factor for the injection of E&P wastes into Class IID wells was that the "waste must have been brought up to the surface in connection with oil and gas production." However, EPA noted some examples in the past of flexibility that can be exercised in determining what additional fluids can be injected. This "flexibility" cited for past regulatory changes included amendments to regulation on cooling tower and boiler blowdown waters as well as policy on scrubber liquids and softener regeneration brines, neither of which was brought to the surface in connection with oil and gas production. EPA cautioned that the guiding principle behind these decisions is that the wastes have to be closely related to the treatment and handling of produced fluids. This is the same principle used to identify E&P wastes as referenced by Region VI in their letter to the Louisiana OC. It appeared that EPA-Washington, instead of issuing nationwide Guidance for Class II fluids, preferred to allow the EPA Regions and the states to address this issue the best way they saw fit. In fact, EPA-Washington stated: "The majority of oil and gas producing states maintain primary enforcement authority for their Class II UIC programs. Because these states have demonstrated that their UIC programs fully protect sources of drinking water, we trust their judgment and determination on whether or not a particular waste fits within the guiding principles described above." It appeared, at this time, EPA-Washington had decided not to issue nationwide Guidance for identifying Class IID fluids eligible for injection.

Alaska Enforcement on Class II Fluids – 1996

It was understood that one reason EPA Headquarters withdrew from issuing nationwide guidance on Class IID fluids injection was that an enforcement action by Region X in Alaska was in the making concerning this particular issue. An oil and gas operator had injected fluids into a well that EPA Region X believed was not eligible for Class II well disposal. Until this enforcement action was settled, guidance on fluids eligible for Class IID injection would not be issued.

National UIC Technical Workgroup Effort – 1997

As a result of the enforcement action by Region X in Alaska, the Alaska Oil and Gas Conservation Commission (AOGCC) posed two broad questions to the Agency pertaining to fluids eligible for Class IID injection. Region X turned to the EPA National UIC Technical Workgroup for an interpretation. This fact is noted in the Workgroup's paper under the Section titled "National UIC Technical Workgroup Consensus and Rationale". (38) The Section starts by stating: "EPA Region X raised 2 questions listed at the beginning of this paper to the National UIC Technical Workgroup during the spring of 1997, and received responses from Region III through IX". The Workgroup stated that their document did not set forth any new policy or policy recommendation; however, it would become difficult for the states to see how EPA Regions and state agencies could accept it otherwise.

The development of the Workgroup's document was announced at the GWPC meeting held March 14-16, 1999, in Arlington, Virginia. At the Arlington meeting a number of persons requested copies of the document for review and comment. The work products were sent to these interested persons on March 24, 1999 through a Memorandum from the National UIC Technical Workgroup. (39)

A GWPC workgroup was formed to respond to EPA's Class II fluids document. The persons in the GWPC workgroup represented California, Colorado, Nebraska, Texas and API. A detailed comments package (40) was submitted to the EPA Technical Workgroup on June 18, 1999. The conclusions of the EPA National UIC Technical Workgroup's final draft Class II fluids document completed on December 10, 1999,(38) are as follows:

- "Individual fluid wastes which are E&P exempt under RCRA must have a direct link with the production of oil and gas (waste produced to the surface), natural gas storage or activities at a gas plant which are an integral part of production operations (activities which occur prior to the transportation phase) for the waste fluid to be eligible for injection into a Class IID well. The eligibility criteria hinges on the waste exhibiting one of 4 possible origins: (1) brought to surface in connection with oil and gas production, (2) brought to surface in connection with oil or gas production and subsequently physically or chemically altered in a manner which is integrally related to oil and gas production or storage, (3) gas plant waste associated with production operations, or (4) fresh water. Thus, there may arise some situations where a particular fluid waste is determined to be E&P exempt but does not qualify for injection into a Class IID well.
- Each component of a fluid mixture must be individually eligible for Class IID injection. Otherwise, the entire waste stream would need to be injected into a Class I well.
- The UIC regulations, which define Class I and Class II disposal wells, are fairly clear and do not allow for widely divergent interpretations across the U.S."

Many Primacy states and industry did not agree with EPA's draft document. It was well known (as discussed in the histories of RCRA and the SDWA) that E&P wastes, as defined by the Office of Solid Waste, have been injected into Class IID wells since the beginning of the UIC Programs in 1982. (5) It is only after an enforcement action in Alaska that this issue really became controversial. Nevertheless, states (and industry) continued to believe the April 1993 letter from Region VI did officially approve Class IID injection of all E&P wastes. As mentioned previously, many states believed the Knudson letter was official since Region VI never informed the Louisiana OC it was not, accompanied by the fact, that EPA-Washington did not issue alternative national guidance on this issue.

Ground Water Protection Council State Survey on Waste Fluids Eligible For Injection Into Class IID Wells - 2000

The GWPC noted the controversy arising over the potential issuance of the EPA National UIC Technical Workgroup's final draft document addressing fluids eligible for injection into Class IID wells. Many state regulatory agency members of the Ground Water Protection Council expressed concern that the draft document did not reflect actual practice in UIC programs across the nation. Consequently, GWPC conducted a survey of primacy and direct implementation (DI) states to gather information on the types of fluids the states and EPA Regions had authorized for injection into Class IID wells.

States and EPA Regions were asked to complete a survey questionnaire so comparisons could be made of the fluid types eligible for disposal into Class IID wells in different programs. The questionnaire was developed with the support of representative states from EPA Regions V through X and also with the support of the EPA National UIC Technical Workgroup. The agreed upon questionnaire (40) was sent to 29 states and 8 EPA Regions. EPA administered DI programs in 6 of the states being surveyed.

Based on the responses in the returned questionnaires, the states and EPA Regions were classified into five categories based on the criteria they use to define wastes eligible for disposal into a Class II well. The categories were:

(1) Oil and gas exploration and production exempt waste plus non-hazardous non-exempt waste directly associated with the exploration and production of oil and gas that are mixed with oil and gas exploration and production exempt waste.

(2) Oil and gas exploration and production exempt waste.

(3) Fluids that are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Also included are exploration and production wastes that are classified as non-hazardous by the California Division of Oil, Gas and Geothermal Resources based on the California assessment manual on a case-by-case basis.

(4) Fluids that are brought to the surface in connection with conventional oil and natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as hazardous waste at the time of injection. Also included are certain fluids from beyond the lease custody transfer boundary that test non-hazardous waste using the Toxicity Characteristic Leachate Procedure (TCLP).

(5) Fluids that are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants that are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Also included are other fluids identified in a policy statement by Michael B. Cook, Director of the EPA Office of Drinking Water, on July 31, 1987.

After assigning each state and EPA Region to a category based on the survey responses, the project team contacted the states and EPA Regions to confirm the assignments. Survey results [42] showed the percentage of Class IID wells by category. Approximately 61% of Class IID wells were regulated by Category (1) states with primacy under Section 1425 of the Safe Drinking Water Act (SDWA). Another 26% of Class IID wells were regulated under Section 1425 state primacy programs in Category (2). All but one EPA Region and all DI states fell under Category (5). The primacy states and the Regions/DI states were at different ends of the scale.

The survey report concluded that the concerns of the state regulatory agencies administering primacy programs were well founded. Most oil and gas producing states were operating under SDWA Section 1425 primacy agreements since the early to middle 1980s, and these states had allowed E&P wastes to be injected into Class IID wells as the API 1985[5] and 1995[13] Waste Survey's had demonstrated. Under these primacy agreements, the State Directors had acted in accordance with EPA's decision that:

> . . . national minimum standards are not the appropriate place to classify all individual practices, some of which may be unique to geological and hydrologic conditions or the regulatory program peculiar to one or a few states. The classification scheme is intended as a framework for State Directors and the decision to place . . . borderline wells in one class or another shall be made on a case-by-case basis. [43]

By restricting the flexibility and discretion of the State Directors to determine fluids eligible for disposal into Class IID wells, the draft document conclusions of the EPA UIC Technical Workgroup would affect large numbers of injection wells and the oil and gas production associated with them. Further, EPA has stated on their Website "when wells are properly sited, constructed, and operated, underground injection is an effective and environmentally safe method to dispose of wastes".[44] Therefore, the Workgroup's draft conclusions would not only be costly, but they would not provide any human health or environmental benefit to this national program.

Conclusions

This Regulatory Review and GWPC State Survey demonstrate that all E&P exempt wastes are considered eligible for injection into Class IID wells in most Section 1425 states. The mixing of E&P exempt wastes with non-hazardous non-exempt wastes has also been interpreted as an eligible fluid in some programs. Following are conclusions along with facts from this review and survey that justify these statements:

1. The GWPC State Survey results of 29 primacy states and 8 EPA Regions with 6 direct implementation states demonstrate all E&P wastes are eligible for Class IID injection. Eighty-seven percent of the Class IID injection wells nationwide are presently used to dispose of E&P wastes. Sixty-one percent are used to dispose of E&P wastes mixed with non-hazardous non-exempt wastes.
2. A past Regulatory Review accurately forecasts the final GWPC State Survey results before the State Survey was implemented. Consequently, it was expected that the State Survey results would show that most Section 1425 primacy states allowed the injection of all E&P wastes into Class IID wells.
3. Nationwide Waste Surveys conducted in 1985 and 1995 by API show that E&P wastes were injected into Class IID wells routinely. As regards E&P associated wastes, it was reported in 1995 that 477,000 barrels of tank bottoms, 7,700 barrels of dehydration wastes, 1,183,000 barrels of completion wastes and 5,621,000 barrels of workover wastes were injected into Class IID wells. It should be noted

that the titles of each wastes, such as "workover and completion wastes", have different types of wastes listed under their broad titles as shown in Table ES-1 of the associated waste reports.[8] The study also showed that 33% of the states that reported Class II disposal of these wastes were Direct Implementation states and that 67% were primacy states.

4. E&P wastes exempted from Subtitle C under RCRA and E&P wastes eligible for injection into Class IID wells under SDWA were both recognized by Congress as the same wastes being regulated under both Acts. The law firm, McGuire, Woods, Battle and Boothe,[1] documented this fact in their report to API regarding litigation on RCRA. In addition, scrubber liquids and boiler blowndown waters were not listed in the 1988 Regulatory Determination[7] as E&P wastes, but were later included by the Office of Solid Waste after the Office of Drinking Water approved these waters for Class IID injection.
5. The Office of Drinking Water has used RCRA language on several occasions to define eligible fluids for injection. The last time fluids eligibility came into question was in 1987 for air scrubber and water softener regeneration brines in California. In that regard, EPA used the phrases <u>integral part</u>, <u>integrally associated</u> and <u>integrally related</u> to approve injection of these fluids into Class IID wells. These type phrases were also used to assist in defining RCRA E&P wastes.
6. A Federal Advisory Committee was formed in 1991-92 to implement changes recommended by a 1988-89 Midcourse Evaluation UIC Committee made up of state and federal agencies; the fluids eligible for injection into Class IID wells were never considered an issue in either one of these efforts. Up until 1993, the only issues that addressed eligible injection fluids were those that evaluated fluids not considered E&P wastes, but all were later included for injection after review by the Office of Drinking Water and Office of Solid Waste.
7. EPA Region VI has always known that E&P wastes were being injected into Class IID wells since inception of the UIC programs in 1982.[29] Sixty-one percent of the Class IID injection wells nationwide are presently used in Region VI to dispose of E&P wastes.
8. By restricting the flexibility and discretion of the State Directors to determine fluids eligible for disposal into Class II wells, the EPA UIC Technical Workgroup's draft document would negatively affect large numbers of injection wells and the oil and gas production associated with them.

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29) Letter from H. W. Thompson, Commissioner, Louisiana Office Of Conservation, to Myron O. Knudson, Director, EPA Region VI, titled Commercial Class II Disposal Wells, Nonhazardous Oilfield Waste (NOW) Fluid Disposal, Louisiana Statewide Order No. 29-B, February 3, 1993
30) Draft Memorandum from James R. Elder, Director, Office of Ground Water and Drinking Water, to Water Management Division Directors titled RCRA – Exempt Oil and Gas Exploration and Production Wastes and Authorization for Injection into Class II Wells – Underground Injection Control Program Guidance #XX, March 7, 1993
31) Memorandum from Francoise M. Brasier, Chief, Underground Injection Control Branch, to Drinking Water Branch Chiefs, UIC Section Chiefs, Region II-X, titled Clarification on Acceptable Wastestreams into Class II disposal wells, March 19,1993
32) Letter from Mr. Myron O. Knudson, EPA Director, Region VI, Water Management Division, to Mr. H.W. Thomson, Commissioner, Office of Conservation, Louisiana Department Of Natural Resources titled Class II Wastestream Clarification, April 20, 1993
33) 58 FR 15284, March 22, 1993
34) Letter to Bill Freeman, Sr. Staff Environmental Engineer, Shell Oil Company from James H. Welsh, Director, Louisiana Injection & Mining Division, titled EPA Waste Stream Clarification, Class II Disposal Wells, May 3, 1993
35) Memorandum from Bruce J. Kobelski, EPA Chief, Regulation Development and Technical Guidance Section, UIC Branch to UIC Section Chiefs, Regions I-X, titled comments on Draft Guidance for RCRA-Exempt Wastes Allowed for Disposal into Class II UIC wells, March 21, 1994
36) Resolution Recommending the US Environmental Protection Agency – Office of Ground Water and Drinking Water - Issue An Updated Guidance To Regions I-X Clarifying The Types Of Waste Fluids Qualified For Injection Into Class II Wells, Spring 1996 GWPC Meeting, Alexandria, Virginia
37) Memorandum from Bob Blanco, EPA Director, Office of Ground Water and Drinking Water, Washington D. C. to Ground Water Protection Council, July 26, 1996

38) Draft-National Underground Injection Control (UIC) Technical Workgroup, Waste Fluids Eligible For Injection Into Class II Disposal (Class IID) Injection Wells, Revised December 10, 1999
39) Memorandum from EPA's Nathan Wiser, Workgroup Chair To Addressees, titled Transmittal of Requested Work Products From the National UIC Technical Workgroup, March 24, 1999
40) Comment Package from David Bolin, President, GWPC, To Nathan Wiser, EPA, National Underground Injection Control (UIC) Technical Workgroup, titled Comments on the Draft Document Entitled "Waste Fluids Eligible For Injection Into Class IID Injection Wells" Developed By the EPA National UIC Technical Workgroup, June 18, 1999
41) Ground Water Protection Research Foundation, Survey On Waste Fluids Eligible For Injection Into Class II Disposal Wells, Questionnaire, December 7, 1999
42) Ground Water Protection Research Foundation, Survey on Waste Fluids Eligible for Injection into Class IID Wells, September 26, 2000
43) 47 Fed. Reg. 4995, February 3, 1982
44) EPA Headquarters UIC Program Homepage, What is the UIC Program? (Last Updated September 26, 2000)

CERA Project: Technical and Economic Evaluation of the Protection of Saline Ground Water Under the Safe Drinking Water Act and the UIC Regulations: In early 1999, this project began by retaining Dr. Don Warner to complete the consulting work on the study. The study completed in June of 2001 included the research as follows:

1) The Safe Drinking Water Act

- Legislative history of the definition of a USDW
- Significance of the USDW definition in the UIC regulations

2) Use of saline ground water in the United States

- Overall use
- Public and self-supplied water use
- Use in California, Florida and Texas
- Limitations on use of untreated saline ground water for human, livestock and agricultural purposes
- Technology and economics of desalination of saline ground water

3) Potential cost benefits to the injection well users from redefinition of aquifers to be protected

In June, 2001 the draft final report was prepared. The following is the Executive Summary and conclusions of the report. *The complete report can be found in Attachment A - in hard copy only.*

Technical and Economic Evaluation of the Protection of Saline Ground Water Under the Safe Drinking Water Act and the UIC Regulations

EXECUTIVE SUMMARY

Injection through Class I, II, III and V wells is regulated under provisions of the Environmental Protection Agency (EPA) Underground Injection Control (UIC) regulations that were developed pursuant to the Safe Drinking Water Act (SDWA) of 1974. In developing the UIC regulations, EPA defined a USDW, in part, as an aquifer or its portion in which the ground water contains 10,000 milligrams per liter (mg/L) or less of total dissolved solids (TDS). EPA then proceeded to develop detailed UIC regulations to protect USDWs. The UIC regulations are believed to be unnecessarily costly to injection well users because of the requirement to protect ground water so saline that it is not now being used nor is it likely to be used in the future for public water supply, the only use that is covered under the SDWA. Therefore, a study was conducted to establish a basis for reconsideration of the USDW definition.

As a first task in this study, the legislative history of the Safe Drinking Water Act was researched to find any basis in that history for the USDW definition adopted by the EPA in the UIC regulations. The second task was to determine the extent of use of saline ground water in the U.S. as one criterion for identifying aquifers that might reasonably require protection. The purpose of the UIC regulations is the protection of ground water that "can reasonably be expected to supply any public water system." In the present study, the current use of saline ground water for public supply has been investigated in 30 oil-producing states to determine what quality of ground water may reasonably require protection today.

In addition to public supply use of saline ground water, self-supplied use, irrigation use and use for stock watering were studied in Texas. The principal source of data for study of the use of saline ground water in Texas was the ground-water database maintained by the Texas Water Development Board (TWDB).

In determining what aquifers require protection, based on the TDS content of contained ground water, it is useful to know the inherent limitations on the quality of untreated water that can be used for public supply and other purposes. For example, the EPA recommended maximum TDS level in drinking water is 500 mg/L and, in Texas, the recommended limit is 1000 mg/L. However, such limits are not presently enforced as mandatory standards and many public water suppliers deliver water with TDS contents much higher than the recommended limits. Furthermore, self-supplied users are not constrained by existing standards or criteria. Therefore, the existing information on use limits based on biological or other factors was investigated.

Extensive use of saline ground water for public supply and other TDS sensitive uses is believed to require desalination. Desalination or desalting is a treatment process whereby fresh water is produced from saline water and a more concentrated salt-water stream results as a residual by-product that must be disposed. The technology available for and the cost of desalination are believed to be important to the question of the need to protect saline ground water that would not, otherwise, be a usable resource. The technology, present use and economics of desalination were, therefore, investigated with regard to their influence on the need to protect saline ground water.

It is intuitive that the cost of well construction, operation and abandonment will be less if the subsurface depth of aquifers to be protected during those processes is reduced. Because the TDS content of ground water commonly increases with depth, reduction of the TDS content of water requiring protection will often result in cost savings to well operators. Therefore, ICF Consulting evaluated the cost savings that could be realized by a less stringent definition of a USDW, as part of this study.

As a result of the study outlined above, the following conclusions were developed.

CONCLUSIONS

1. In establishing the UIC regulations, EPA characterized ground water aquifers to be protected during injection well construction and operation as underground sources of drinking water (USDWs) and defined a USDW. By that definition, a USDW includes an aquifer or its portion that supplies drinking water for human consumption or in which the ground water contains fewer than 10,000 mg/L total dissolved solids (TDS) and is not an exempted aquifer (could reasonably be expected to serve as a public drinking water source in the future).

2. Because there is no evidence that EPA ever conducted a scientific study to determine that its definition of a USDW was appropriate, the legislative history of P.L. 93-523 was researched for such evidence. In House Committee Report 93-1185 on H.R. 13002, within the section on "Endangerment of drinking water sources" it is stated that: "...

...the Committee expects the Administrator's regulations at least to require States to provide protection for subsurface waters having less than 10,000 p.p.m. dissolved solids, as is currently done in Illinois and Texas" No basis for the Committee's statement of intent concerning ground water to be protected was found in any House or Senate bill, testimony or report.

3. A search was made for a source for the comment from House Report 93-1185 that accompanied H.R. 13002 relative to the protection of subsurface waters having less than 10,000 p.p.m. dissolved solids in Illinois and Texas. It was found that, in both states, agency documents did exist that could possibly have been the sources of the comment in the House Report. Neither document was peer reviewed or published and the policies advocated in the documents were never adopted in either state.

4. The principal source of water use information for the United States is the U.S. Geological Survey, which, every five years, publishes data on estimated water use in the U.S. These national water-use compilations began in 1950. The most recent such summary was for water use in 1995. Study of the U.S.G.S. data and procedures led to the conclusion that there are no reliable national data on saline ground water withdrawal and that public supply use of saline ground water, the category of principal interest in this study, is not reported at all by the
U.SG.S.

5. The current use of use of saline ground water for public supply has been investigated in 30 oil-producing states to determine what quality of ground water may require protection today on the basis of present use. Of the 30 states, 14 reported no known use of saline ground water for public supply, five reported very limited use and eleven reported significant use. In the states that reported withdrawal of saline ground water for public supply, a large number of systems were found to use ground water with from 1000-2000 mg/L TDS, a smaller number use water with 2000-3000 mg/L TDS and very few use water with >3000 mg/L TDS. It is believed that Florida uses the largest volume of saline ground water for public supply of any state and, in Florida, only 3% of the ground water withdrawn for public supply in 1995 was saline. While the data are for the present and do not establish the quality of water that may be used in the future, it is considered relevant that, according to the U.S.G.S. "after continual increases in the Nation's total water withdrawals ... ... from ... ... 1950 to 1980, withdrawals declined from 1980 to 1995 ... ... even though population increased 16 percent from 1980 to 1995." This finding suggests that there may have been little need to use increasingly poorer quality ground water, except in certain local or regional situations, during that period. It also casts doubt on projections of rapidly increasing water demands that might lead to the use of poorer quality ground water in the future except under particular local or regional circumstances.

6. The use of saline ground water for public supply has been affected by EPA primary water quality standards that have forced some systems to abandon a saline ground water source or to provide costly treatment because the raw water contained a regulated contaminant in excess of the MCL. Potential future regulatory actions could impose

further limitations to use of saline ground water for public water supply by regulating the levels of sulfate and/or sodium, two of the principal constituents of TDS.

7.While EPA does not presently regulate TDS or its major component chemicals, individual states can do so. For example, Texas has a secondary recommended constituent level for TDS of 1000 mg/L and, the Texas regulations state that "For all instances in which drinking water does not meet the recommended limits and is accepted for use by the commission, such acceptance is valid only until such time as water of acceptable chemical quality can be made available at reasonable cost to the area(s) in question." Staff of the Texas Natural Resource Conservation Commission have indicated the Commission's intent to eventually have all public systems meet the TDS secondary standard. Similar TDS secondary standards and policies concerning them have also been found to exist in Florida and probably exist in other states, as well. The long-term consequence of such regulations and policies may be to further limit the use of ground water with TDS greater than 1000 mg/L.

8. Although ground water with TDS levels of 2000-3000 mg/L is being used in some areas for drinking water, there are other problems besides human health effects that can arise from its use at residential and industrial locations. First, scaling and corrosion problems can occur in the water well and in the piping used for transporting this water to and distributing within the residential or industrial complex. In fact, the Texas drinking water standards require corrosion control, if necessary, to meet lead and copper standards. Corrosion control or treatment of the water to reduce its corrosivity can be costly. Second, the use of such water for plants, gardens and lawns can limit or prevent plant growth and can damage the soils. Lastly, water with TDS levels in this range cannot be used in many industrial processes.

9. The use of saline water for irrigation and livestock watering has significant limitations. A critical review of ground water quality criteria for agricultural use shows that groundwater of 3000 -10,000 mg/L TDS is not generally usable for irrigation without dilution or desalination treatment to reduce the salinity level or the adoption of special irrigation practices. Also, water with 10,000 mg/L TDS concentration is far in excess of that which can reasonably be considered a safe limit for most poultry and livestock. A value of 3,000 mg/L TDS is a more reasonable concentration. For that reason, waters in excess of 3,000mg/L TDS should be diluted or treated to reduce the salinity prior to using it for watering farm animals or poultry.

10. It is believed that, where ground water is more saline than about 3000 mg/L, desalination is required for it to be used for drinking water. According to a survey by the U.S. Bureau of Reclamation, there were 178 potable water supply desalination plants with a capacity of267 Mgal/d in operation in 1996. That capacity could provide for 0.66% of the total 1995 U.S public water supply. Some of those plants use seawater or brackish surface water as a source and many of the plants treat water that is, by definition, not saline. Only a very small number of scattered plants withdraw and treat ground water with TDS >3000 mg/L. Because the cost of desalination is closely related to the salinity of plant feedwater, there is strong motivation to use the lowest salinity of water that can be obtained, if other factors to be considered, such as source depth or

distance, are equal. This fact mitigates against the use of very saline ground water and is probably an important reason for the present lack of its use except in unusual circumstances.

11. It is intuitive that the cost of well construction, operation and abandonment will be less if the subsurface depth of aquifers to be protected during those processes is reduced. Because the TDS content of ground water commonly increases with depth, reduction of the TDS content of water requiring protection will often result in cost savings to well operators. A study by ICF Consulting of the cost savings to be realized by a less stringent definition of a USDW estimates that the potential total annual cost savings range from $136 million to more than $1.0 billion (1998 dollars). The present value of the total cumulative cost savings for the 21-year period from 2000 to 2020 ranges from $1.35 billion to $10.0 billion.

12. Findings are contained in this report that would justify reconsideration of the present USDW definition or would provide a logical basis for expedited aquifer exemptions, particularly with the objective of reducing the cost of new well construction and the plugging of existing wells.

Members of the GWPRF Board of Directors are in the process of reviewing the final draft report.

CERA Project: Central Oklahoma Base of Treatable Water Mapping Project

The following is the Abstract and Introduction of the report. *The complete report can be found in Attachment B.*

CHARACTERIZING AND MAPPING THE REGIONAL BASE OF AN UNDERGROUND SOURCE OF DRINKING WATER IN CENTRAL OKLAHOMA USING OPEN-HOLE GEOPHYSICAL LOGS AND WATER QUALITY DATA

ABSTRACT

Oil And gas operators are required to set sufficient lengths of surface casing in wells to prevent the migration of fluids into Underground Sources of Drinking Water (USDWs). An empirical method is presented for using open-hole geophysical logs and water quality data to quantify TDS concentrations in the fresh water portions of an USDW. The technique was applied to generate regional elevation maps of the base of the USDW in three counties in Central Oklahoma. The maps will allow regulators and other stakeholders to visualize the areal and vertical limits of the USDW, and provide a practical basis for making informed decisions that pertain to surface casing depth-setting requirements.

The log interpretation techniques that are presented can be extended to USDWs in other geographical areas. The specific associations between open-hole geophysical log responses, water chemical data and formation petrophysical properties developed in this study were determined empirically. Similar empirical relationships must be established whenever open-hole geophysical logs and water quality data are going to be used to evaluate ground water conditions in other USDWs.

INTRODUCTION

The Safe Drinking Water Act (SWDA) requires that Underground Sources of Drinking Water (USDWs) be protected from being impacted by the fluids that are used, injected or produced in connections with petroleum drilling and production operations. USDWs are defined as any subsurface formation that contains ground water having a total dissolved solids (TDS) concentration less than 10,000 milligrams per liter (mg/L). To prevent USDWs from being impacted by petroleum-related activities state oil and gas regulatory agencies have established a variety of protection standards. One such standard requires that oil and gas operators set sufficient lengths of surface casing in wells to prevent the movement of fluids into USDWs. In Oklahoma, the Oklahoma Corporation Commission (OCC) requires that surface casing be set such that the bottom of the casing extends 50 feet below the base of the lowermost USDW.

Adequate information is not always available about local depths to the base of USDWs. Consequently, many oil and gas operators elect to install more surface casing than is actually needed to meet federal and state protection requirements. For example, the OCC estimates that of the nearly 3,100 wells permitted for drilling in Oklahoma each year, approximately 60% are completed with an average of 200 feet of unnecessary surface casing. The cost to drill, case and cement this additional footage is estimated to represent an $18.0 million per year impact to the Oklahoma petroleum industry. Conversely, wells are sometimes completed inadequately, placing ground water supplies at risk of becoming impacted. In the event that an USDW is impacted to the degree that remediation is necessary, the clean-up and associated ancillary cost would most assuredly be substantial.

A practical remedy to this problem can be found in the million of geophysical logs that have been recorded in oil and gas wells. This important data resource can be used to characterize the subsurface hydrogeologic and water quality conditions that define an USDW. The value and application of open-hole geophysical logs was recognized in the 1940's when it was demonstrated that they could be used to assess the productive potential of petroleum reservoirs. Their role as a ground water evaluation tool is evolving, as their application to subsurface hydrogeologic and ground water quality studies is still not widely recognized.

This study had two primary goals. The first goal was to present a cost-effective, scientifically defensible and practical method that could be applied in other geographic areas to comply with surface casing depth-setting requirements. To meet this objective, the study investigated the feasibility of using existing open-hole geophysical logs and water quality data as tools for defining the vertical limit of an USDW. The end result was the development of a method for interpreting open-hole geophysical logs that can be applied to characterize and map the elevation of the water quality boundary condition that defines the base of an USDW. The elevation maps, when used in conjunction with surface topographic amps, will provide regulators and oil and gas operators with the information that is needed to determine surface casing depth requirements that are protective of ground water resources. Petroleum operators should also be able to reduce surface casing expenditures as well as their potential exposure to environmental liability.

Using TDS as an indicator, the second goal of the study was to demonstrate that open-hole geophysical logs can be used to accurately quantify basic water quality conditions in an USDW without having to conduct costly intrusive investigations or collect ground water samples. The techniques that are presented in this study can be applied to generate the data needed to construct regional ground water quality maps in other geographical areas. Maps of this kind would be of considerable value because they could empower regulators and other stakeholders with the ability to visualize the areal and vertical distribution of regional ground water quality in USDWs. As a result, regulators would have a practical basis for making informed decisions that pertain to permitting issues, evaluating contamination risks, resolving water quality disputes, and formulating or revising strategies for managing and exploiting existing ground water resources.

An auxiliary objective of this study was to increase awareness of the fact that, as a consequence of nearly five decades of oil and gas drilling in this county a tremendous amount of open-hole geophysical data has been recorded and collected. This information, when combined with ground water chemical data, can be used for a variety of ground water related applications, including but not limited to the following:

- Assessment of regional water quality and source water conditions;
- Performance of protection and vulnerability assessments;
- Quantification and assessment of aquifer physical properties such as porosity, yield (moveable water), storage capacity, transmissivity, and permeability (hydraulic conductivity);
- Characterization of aquifer boundary conditions (physical and chemical);
- Improved understanding of hydrogeologic conditions affecting regional ground water flow;
- Development of conceptual models for enhancement of ground water modeling, ground water exploitation, management and protection programs;
- Design and implementation of aquifer recovery and storage (ASR) programs;
- Locations of new or alternate supplies of ground water; and
- Evaluation of drinking water treatment requirements and disposition of treatment sludges.

In accordance with the stated objectives, this study demonstrated that the log interpretation techniques and data used in petroleum industry applications can be adapted to quantify and map ground water quality conditions in an USDW. This is exemplified by the fact that open-hole geophysical logs recorded in over 850 wells, spread across an area of approximately 2,000 square miles, were used to characterize and map the base of the Central Oklahoma USDW.

CERA Project: San Juan Basin Ground Water Modeling Study: Ground Water – Surface Water Interactions Between Fruitland Coalbed Methane Development and Rivers

The following is the Executive Summary. *The complete report can be found in Attachment C.*

Executive Summary

The Ground Water Protection Research Foundation (GWPRF) sponsored this project to model surface water and ground water interactions associated with coal bed methane (CBM) development in the northern San Juan Basin of Colorado, which is the world's premier CBM producing area. Ground water production from coalbed aquifers is required for recovering CBM. By pumping water, the pressure in the CBM reservoir is reduced and methane then desorbs from the coal and flows through the natural cleat system to the pumping wells. This project was designed to quantify the maximum surface water depletion that may occur as a result of CBM development in the Fruitland Formation.

Previous work had shown that, prior to CBM development, approximately 194 ac-ft/yr of water was discharging to the main rivers (the Animas, Florida, Pine or Los Piños, and Piedra) from the Fruitland Formation subcrop. Regional reservoir modeling work also indicated that the artesian pressures in the Fruitland Formation were being reduced on a regional scale as a result of dewatering associated with CBM production, and that with future CBM development, a reversal of the hydraulic relationship between the rivers and the Fruitland aquifer might occur. Comprehensive numerical solutions were developed to adequately define a reasonable maximum depletion term.

This study developed multi-layer models at the Animas, Florida, and Pine Rivers. The Piedra River area was not modeled due to lack of geologic and reservoir information. Each model area encompassed a river crossing, adjacent outcrop areas, and several square miles of active CBM producing regions within the basin. The coalbeds were modeled by grouping coals in up to 5 "packages" or layers. The intervening strata were also grouped and assigned to layers. The underlying Pictured Cliffs Sandstone was also modeled as a distinct layer. Overlying and underlying shales were modeled as impermeable boundaries at the bottom and top of the model.

For each model area, MODFLOW was used to define the equilibrium conditions of ground water flow, recharge, discharge, and related potentiometric heads. These results were used as starting conditions in the reservoir model. The reservoir model was then used to simulate the effects of CBM development on the river/ground water interactions.

Supporting fieldwork associated with model development included:

1. The development of geologic cross-sections at each river cut along the outcrop,
2. Geologic mapping near the Piedra River, with stratigraphic sections and mapping of surface water features (springs and wetlands) and existing methane seeps.
3. An assessment of fracture density in the upper Pictured Cliffs Sandstone,
4. Stable isotope sampling from various CBM wells, and

5. An assessment of the hydraulic properties of non-coal or clastic sedimentary deposits of the Fruitland Formation.

The models in this study were purposely developed to err on the conservative side, to provide a reasonable upper limit for potential surface water depletions. Models were constrained by the available data, but when estimates were required or there was a range of potential values for a parameter, the investigators chose the value that might give a higher depletion value.

As of 2001, approximately 65 ac-ft/yr are being depleted from surface waters. Depletions will continue to increase as long as CBM production occurs, although most of the impacts will occur within the next 30 to 50 years. Maximum surface water depletions associated with full-field CBM development (at 160-acre well spacing) are predicted to be 155 to 200 ac-ft/yr. These numbers are significantly lower than previous estimates of potential stream depletion made by the BLM using analytical techniques.

The depletion values fall well within the 3,000 ac-ft/yr that are allowed for all Federal projects within the San Juan River Basin, and should not impact management of the San Juan River hydrology.

A similar modeling approach should be applicable to other Western US CBM basins, including the Powder River, Uinta, Piceance, and Green River basins, which are also in semi-arid to arid environments with low precipitation, low and/or sporadic recharge, snowmelt recharge, and generally multiple-layered low permeability coal beds, with predominantly fracture-controlled permeability and porosity.

CERA Project: Oklahoma Oil & Gas Peer Review

In April of 2001 the a Ground Water Protection Council peer review team conducted a 4-day review of the Oklahoma Corporation Commission's UIC program. The review team consisted of Wendy MaHan (Alaska), Joe Ball (Louisiana), Bill Bryson (Kansas), and Mike Paque, Dan Yates and Ben Grunewald (GWPC). The following is the questionnaire Table of Contents *Attachment D contains the Oklahoma peer review report*.

PEER REVIEW Questionnaire Table of Contents

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GROUND WATER PROTECTION COUNCIL

GROUND WATER PROTECTION RESEARCH FOUNDATION

CHARACTERIZING AND MAPPING THE REGIONAL BASE OF AN UNDERGROUND SOURCE OF DRINKING WATER IN CENTRAL OKLAHOMA USING OPEN-HOLE GEOPHYSICAL LOGS AND WATER QUALITY DATA

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A study submitted this 29th day of January 2001 to the board members of the Ground Water Protection Research Foundation.

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Reviewed by: ____
Dan S. Spitz, Senior Hydrogeologist,
Enercon Services, Inc., Oklahoma City, OK

Approved: ______________________________________ Date: __________
Ground Water Protection Research Foundation

FOREWORD

A demonstration of the application of open-hole geophysical logs as a ground water quality assessment tool is presented in this report. Geophysical log data was used in combination with ground water quality information to characterize and delineate the base of an Underground Source of Drinking Water.

Therefore, all interpretations and results presented herein were based on inferences from electrical or other measurements and chemical data. Enercon Services, Inc. cannot and does not warrant or otherwise guarantee the accuracy or correctness of any interpretation or the reliability of the data obtained from, or furnished by other sources, and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from the reliance upon any of the interpretation(s) made by any of our officers, agents or employees.

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ACKNOWLEDGEMENTS

The author thanks the Ground Water Protection Research Foundation, the Ground Water Protection Council and the United States Department of Energy for funding this project. Thanks to Mike Paque, Ben Grunewald and Larry Fiddler who helped make this project a reality. Special thanks to my mentors, Gary Stewart, Professor Emeritus, Oklahoma State University and Alvin Schultz, Consulting Geologist, San Antonio, Texas for sharing their wisdom, and incredible knowledge of the art of log interpretation. Thanks are also due to the Association of Central Oklahoma Governments for providing much of the geophysical log and water quality data.

Additional thanks are extended to Melanie Foster who worked hard to acquire all of the data and to develop the database. Thanks to Dan Spitz for assisting with the mapping and reviewing the manuscript. Dan was a great "sounding board" and provided many helpful comments. Grateful appreciation also goes to Julie Evans and Preston Gilmore for preparing and drafting the maps, cross-sections and graphic illustrations. And finally, thanks to my supervisor Robert Davis for supporting me in this endeavor.

ABSTRACT

Oil and gas operators are required to set sufficient lengths of surface casing in wells to prevent the migration of fluids into Underground Sources of Drinking Water (USDWs). An empirical method is presented for using open-hole geophysical logs and water quality data to quantify TDS concentrations in the fresh water portions of an USDW. The technique was applied to generate regional elevation maps of the base of the USDW in three counties in Central Oklahoma. The maps will allow regulators and other stakeholders to visualize the areal and vertical limits of the USDW, and provide a practical basis for making informed decisions that pertain to surface casing depth-setting requirements.

The log interpretation techniques that are presented can be extended to USDWs in other geographic areas. The specific associations between open-hole geophysical log responses, water chemical data and formation petrophysical properties developed in this study were determined empirically. Similar empirical relationships must be established whenever open-hole geophysical logs and water quality data are going to be used to evaluate ground water conditions in other USDWs.

INTRODUCTION

The Safe Drinking Water Act (SDWA) requires that Underground Sources of Drinking Water (USDWs) be protected from being impacted by the fluids that are used, injected or produced in connection with petroleum drilling and production operations. USDWs are defined as any subsurface formation that contains ground water having a total dissolved solids (TDS) concentration less than 10,000 milligrams per liter (mg/L). To prevent USDWs from being impacted by petroleum-related activities state oil and gas regulatory agencies have established a variety of protection standards. One such standard requires that oil and gas operators set sufficient lengths of surface casing in wells to prevent the movement of fluids into USDWs. In Oklahoma, the Oklahoma Corporation Commission (OCC) requires that surface casing be set such that the bottom of the casing extends 50 feet below the base of the lowermost USDW.

Adequate information is not always available about local depths to the base of USDWs. Consequently, many oil and gas operators elect to install more surface casing in wells than is actually needed to meet federal and state protection requirements. For example, the OCC estimates that of the nearly 3,100 wells permitted for drilling in Oklahoma each year, approximately 60% are completed with an average of 200 feet of unnecessary surface casing. The cost to drill, case and cement this additional footage is estimated to represent an $18.0 million per year impact to the Oklahoma petroleum industry. Conversely, wells are sometimes completed inadequately, placing ground water supplies at risk of becoming impacted. In the event that an USDW is impacted to the degree that remediation is necessary, the clean-up and associated ancillary costs would most assuredly be substantial.

A practical remedy to this problem can be found in the millions of geophysical logs that have been recorded in oil and gas wells. This important data resource can be used to characterize the subsurface hydrogeologic and water quality conditions that define an USDW. While the application of open-hole geophysical logs has been recognized since the 1940's as a tool for assessing the productive potential of petroleum reservoirs, their use for characterizing subsurface hydrogeologic and ground water quality conditions is not widely recognized.

This study had two primary goals. The first goal was to present a cost-effective, scientifically defensible and practical method that could be applied in other geographic areas to comply with surface casing depth-setting requirements. To meet this objective, the study investigated the feasibility of using existing open-hole geophysical logs and water quality data as tools for defining the vertical limit of an USDW. The end result was the development of a method for interpreting open-hole geophysical logs that can be applied to characterize and map the elevation of the water quality boundary condition that defines the base of an USDW. The elevation maps, when used in conjunction with surface topographic maps, will provide regulators and oil and gas operators with the information that is needed to determine surface casing depth requirements that are protective of ground water resources. Petroleum operators should also be able to reduce surface casing expenditures as well as their potential exposure to environmental liability.

Using TDS as an indicator, a second goal of the study was to demonstrate that open-hole geophysical logs can be used to accurately quantify basic water quality conditions in an USDW without having to conduct costly intrusive investigations or collect ground water samples. The techniques that are presented in this study can be applied to generate the data needed to construct regional ground water quality maps in other geographic areas. Maps of this kind would be of considerable value because they could empower regulators and other stakeholders with the ability to visualize the areal and vertical distribution of regional ground water quality in USDWs. As a result, regulators would have a practical basis for making informed decisions that pertain to permitting issues, evaluating contamination risks, resolving water quality disputes, and formulating or revising strategies for managing and exploiting existing ground water resources.

An auxiliary objective of this study was to increase awareness of the fact that, as a consequence of nearly five decades of oil and gas drilling in this country a tremendous amount of open-hole geophysical data has been recorded and collected. This information, when combined with ground water chemical data, can be used for a variety of ground water related applications, including but not limited to the following:

- Assessment of regional water quality and source water conditions;
- Performance of protection and vulnerability assessments;
- Quantification and assessment of aquifer physical properties such as porosity, yield (moveable water), storage capacity, transmissivity, and permeability (hydraulic conductivity);
- Characterization of aquifer boundary conditions (physical and chemical);
- Improved understanding of hydrogeologic conditions affecting regional ground water flow;
- Development of conceptual models for enhancement of ground water modeling, ground water exploitation, management and protection programs;
- Design and implementation of aquifer recovery and storage (ASR) programs; and
- Location of new or alternate supplies of ground water.

In accordance with the stated objectives, this study demonstrated that the log interpretation techniques and data used in petroleum industry applications could be adapted for use to quantify and map regional ground water quality conditions in an USDW. This is exemplified by the fact that open-hole geophysical logs recorded in over 850 wells, spread across an area of approximately 2,000 square miles, were used to characterize and map the base of the Central Oklahoma USDW.

DESCRIPTION OF THE STUDY UNIT

The study unit consists of the water-bearing bedrock formations that underlie Cleveland, Logan and Oklahoma Counties in Central Oklahoma. The term "study unit", is borrowed from Parkhurst, et al (1989) and Norvell (1995), and is used instead of "study area" because "area" implies only surficial extent. The focus of the investigation was on the subsurface sedimentary units that comprise the Garber-Wellington Aquifer, because they contain most of the usable ground water in the study unit (Figure 1).

PHYSIOGRAPHY

The eastern part of the study unit is characterized by low hills, generally covered with blackjack and post oaks, with relief of 30 to 200 feet. The western part of the study unit is characterized by a gently rolling grass-covered plain with relief of less than 100 feet. Land surface elevations are generally higher in the west than in the east. The highest surface elevation is approximately 1,400 feet above mean sea level (AMSL) in the western part of the study unit along the drainage divide between the Canadian and North Canadian Rivers. The lowest surface elevation is about 820 feet AMSL along the Cimarron River in Northeastern Logan County (Parkhurst et al, 1989).

The major streams in the study unit are the Cimarron River, the Deep Fork River, the North Canadian River, the Little River, and the Canadian River. These rivers, which flow from west to east, have formed broad, flat alluvial valleys. The headwaters of the Little River and the Deep Fork are located within the study unit.

The mean annual surface temperature in this part of Oklahoma is 60 °F. The average annual precipitation is approximately 33 inches, most of which falls from April to October (Parkhurst et al, 1989).

HYDROGEOLOGIC SETTING

In Central Oklahoma, all Permian sedimentary rocks, and the Quaternary alluvium and terrace deposits overlying them, make up the hydrogeologic system known as the Central Oklahoma Aquifer (Norvell, 1995, Parkhurst et al, 1989). The Permian sedimentary units comprising the Garber-Wellington Aquifer were the focus of this study, because they contain the ground water that characterizes the USDW. Consequently, bedrock formation descriptions are provided for Permian sediments only. The open-hole resistivity log shown in Figure 2 illustrates the stratigraphic relationships that were observed in this study.

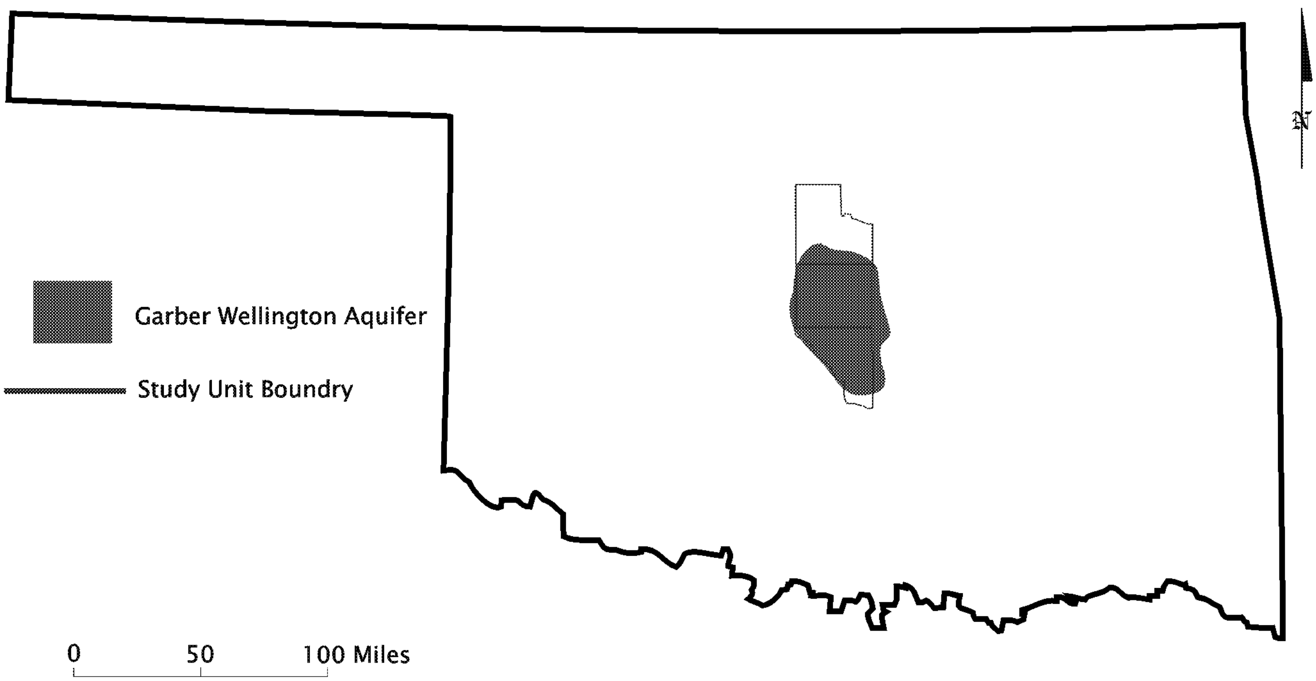


Figure 1: Location of study unit showing limits of Garber-Wellington Aquifer

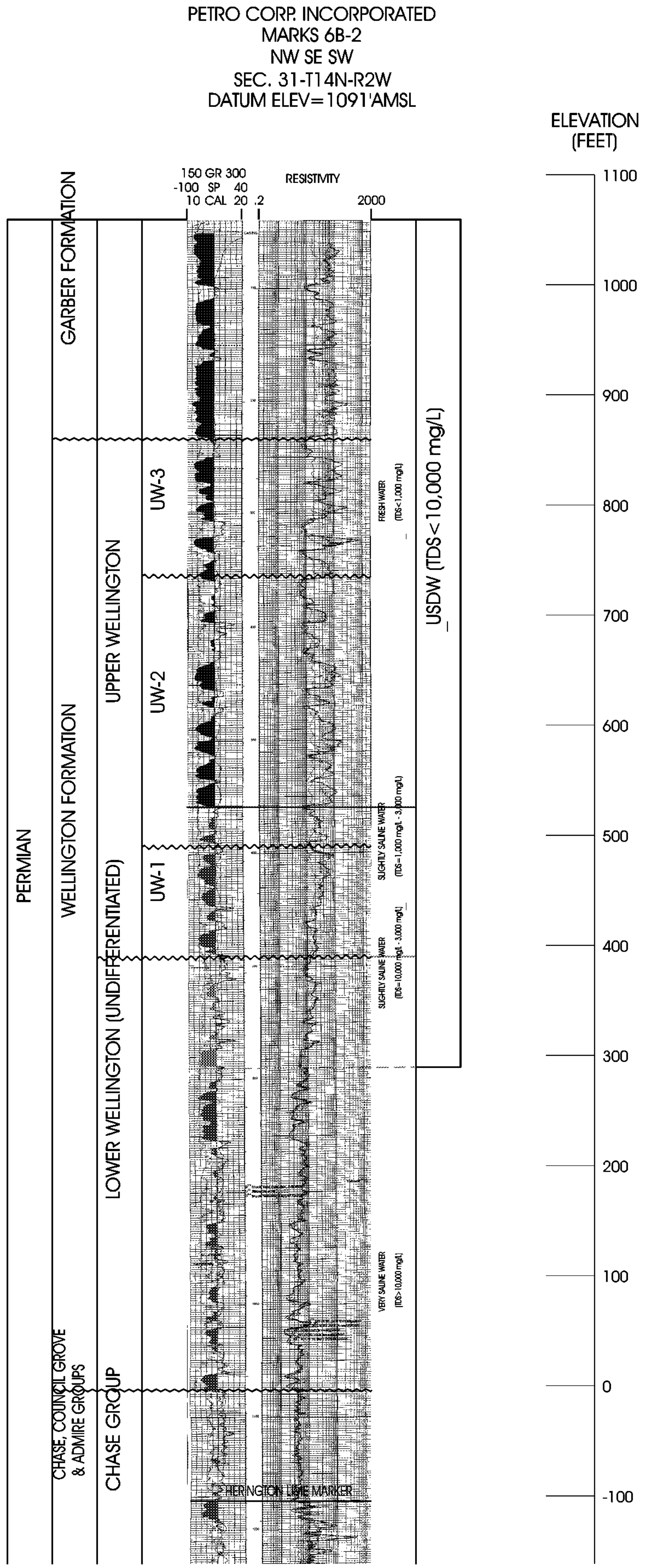


FIGURE 2: INDUCTION LOG RECORDED IN AN OIL & GAS WELL LOCATED IN SECTION 31-T14N- R2W, OKLAHOMA COUNTY. THE LOG ILLUSTRATES THE STRATIGRAPHIC RELATIONSHIPS AND VERTICAL CHANGES IN WATER QUALITY OBSERVED IN THE CENTRAL OKLAHOMA AQUIFER. NOTE THAT TDS CONCENTRATION INCREASES WITH DEPTH. THE SAME VERTICAL CHANGES IN TDS CONCENTRATION OCCUR ACROSS THE ENTIRE STUDY UNIT. THE RELATIONSHIPS BETWEEN VARYING SALINITY AND RANGES IN TDS WERE ADOPTED FROM TERMINOLOGY USED BY THE U.S. GEOLOGICAL SURVEY. THE GENERAL TERM "SALINITY" IS USED TO DESCRIBE WATER THAT IS NOT FRESH.

Hennessey Group

Formations belonging to the Permian Hennessey Group outcrop in approximately the western two-thirds of the study unit. The Hennessey overlies the Garber and Wellington Formations, and consists primarily of shale with lesser amounts of sandstone and siltstone. Limited quantities of fair to poor quality ground water are produced from water-bearing zones in the Hennessey.

The Garber and Wellington Formations

The Garber and Wellington Formations are lithologically similar. For this reason most workers are unable to distinguish between the two, particularly in the subsurface. Both formations consist of numerous layers of porous sandstone. Quite often sandstones have coalesced to form thick water-bearing units while others are interbedded with siltstone and/or shale. Sandstone units in both formations are typically cross-bedded and primarily consist of very fine-grained quartz fragments with interstitial and interbedded mixed-layer illite-smectite clays. Important authigenic minerals commonly encountered in the Garber-Wellington Aquifer include hematite (Fe_2O_3), goethite [$FeO(OH)$], calcite ($CaCO_3$) and dolomite [$CaMg(CO_3)_2$]. A variety of sedimentary features observed both in outcrop and on geophysical logs, suggest that the environment of deposition was fluvial-deltaic (Parkhurst, et al 1993).

Together, these formations comprise the Garber-Wellington Aquifer. Ground water produced from the aquifer is generally of good quality and is used extensively for municipal, industrial, commercial, agricultural and domestic supplies. General water quality relationships are shown in Figure 2.

Chase, Council Grove and Admire Groups

East of the study area, in Lincoln and Pottawatomie Counties, the Permian Chase, Council Grove and Admire groups form the basal members of the Central Oklahoma Aquifer where they contain usable supplies of ground water. These formations underlie the Garber and Wellington formations.

DATA ACQUISITION AND VALIDATION

To perform the study it was necessary to acquire open-hole geophysical logs and ground water quality data. Logs were acquired from the Association of Central Oklahoma Governments (ACOG), the Oklahoma City Geological Society (OCGS) log library and Riley Electric Log (Riley's). Water quality data from twenty-five municipal test wells was obtained from ACOG. Water quality data from seven test wells completed by the U.S. Geological Survey (USGS) was obtained from published information presented in U.S. Geological Survey Open-File Report 91-464 (Shlottmann and Funkhouser, 1991).

An effort was made to collect as much log and water quality data as possible. However, some data was not available, mostly because the vintage of some of the data was such that it has long since been lost or misplaced. Furthermore, the petroleum industry has experienced a great deal of reorganization since 1982. Consequently, companies operating at that time have either been acquired by other companies, declared bankruptcy, or ceased operations altogether and have liquefied their assets. Unfortunately, much data has been lost in the process.

OPEN-HOLE GEOPHYSICAL LOGS

With literally thousands of open-hole geophysical logs having been recorded in the study unit, it was necessary to identify only those logs where measurements had been recorded through the USDW. Of specific importance was the acquisition of open-hole resistivity and porosity logs. Riley's identified much of the data by performing a computerized search of their database. The criteria for the search was to identify open-hole resistivity and porosity logs in the study unit where the shallowest recorded log responses had been made at measured depths less than or equal to 400 feet. A file review of ACOG's log archives resulted in the identification of additional log data. In all a total of 1,194 well logs were identified for possible use in the study. Hard copies of all the logs were scanned and converted into Text Image Format (.tif, i.e. raster images) for easy storage, retrieval and scaling.

To achieve the goals of the study, it was essential that the geophysical log data be reasonably accurate and reliable. Since no log is perfect in every detail, it was necessary to employ several methods and techniques to evaluate the validity of the recorded curves. The following method, adapted from Schultz (1993), was used to examine the logs and determine which ones could be used in the study:

- Examination of each log included a review of the log heading, calibrations, repeat sections (if presented), scales, and remarks.

- Identification of any reported or suspected operational problems was made.

- Measurement scales were verified, and if necessary, log scales were calibrated to conform to established formation data values.
- An examination of each log was made to ensure that the shape and character of the recorded curves were commensurate with the type of device generating the measurement.
- In some cases, calculations were made and compared with known physical and/or chemical parameters to establish the validity of recorded log curves.

Upon completing the log examination phase, open-hole resistivity logs and a few porosity logs recorded in a total of 853 wells were selected for use (Tables D1, D2 and D3). Examples of logs of acceptable quality are presented in Figures 3, 4 and 5. Figures 6, 7 and 8 provide examples of substandard logs that were not used.

WATER QUALITY DATA

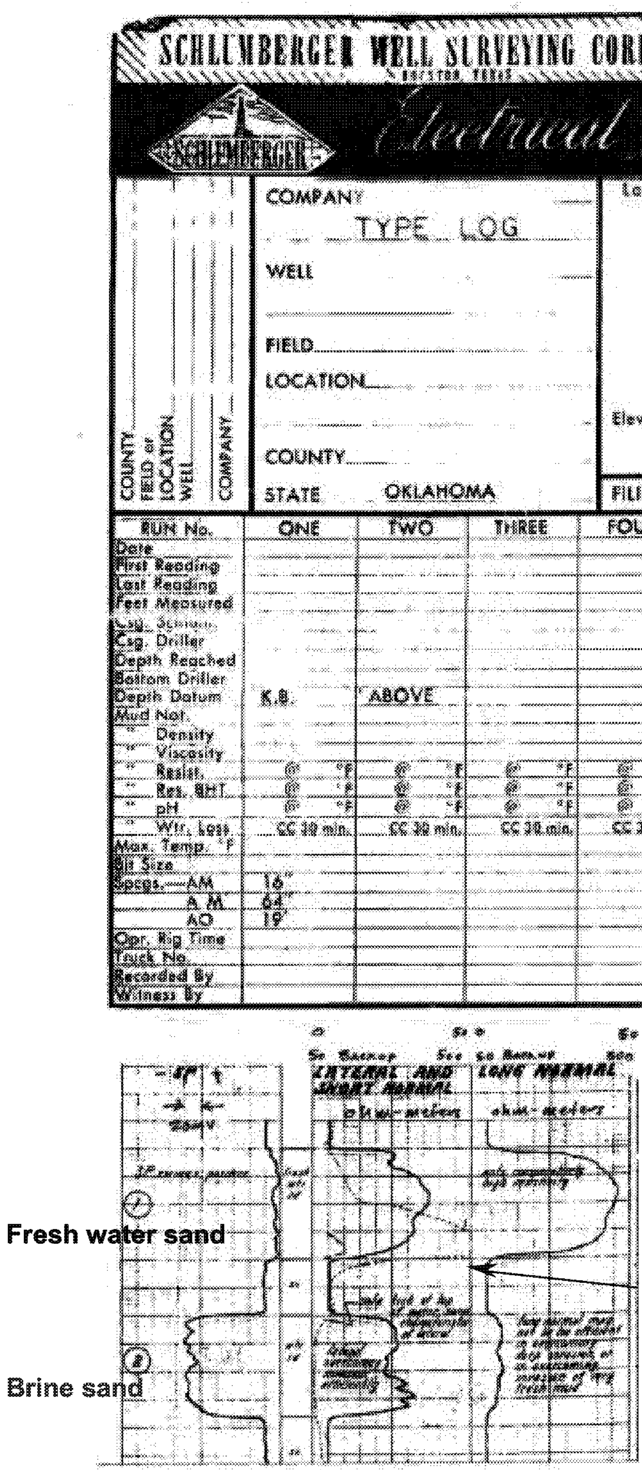
The municipal and USGS water quality data used in this study was zone-specific, meaning that the samples had been collected from discrete water-bearing zones. In general, four to six ground water samples were collected from a well and submitted to a laboratory for chemical analysis. Concentrations of the major ion/ionic pairs and trace elements were presented with the laboratory results.

However, a preliminary review of all water quality data revealed that total dissolved solids (TDS) and water conductivity data were inconsistently reported. TDS values were reported with the municipal test well data results, but conductivity values were not. Conversely, no TDS data was reported with the chemical analyses presented in USGS Open-File Report 91-464 (Shlottmann and Funkhouser, 1991), but conductivity values were. No documentation was provided with either of the two data sources to indicate why this had occurred.

Because TDS and conductivity were the primary water quality parameters of concern in this study, an understanding of their relationship to the chemistry of water and how their values are determined is necessary.

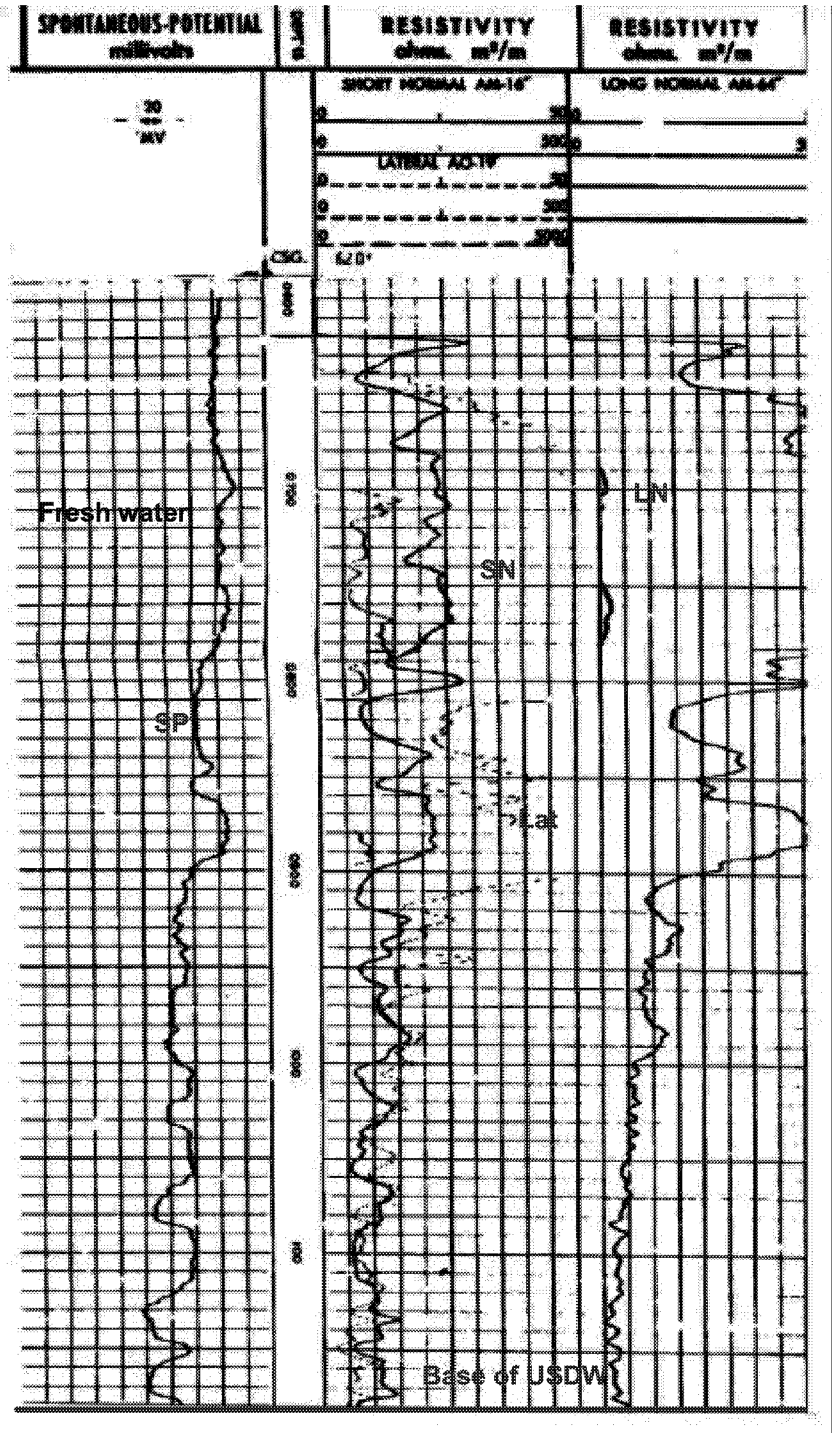
Determination of Total Dissolved Solids

In 1956 A.G. Winslow and L.R. Kister at the U.S. Geological Survey (USGS) adopted the use of the general term saline to describe water that was not fresh. They proposed that varying degrees of salinity could be characterized by ranges in TDS concentration (reported in mg/L) utilizing the following convention:



Log shows typical curve responses produced by Short Normal (SN), Long Normal (LN) and Lateral (Lat) resistivity measuring devices in a fresh-water sand. Note that the Spontaneous Potential (SP) curve deflects to the right (+ deflection) of the shale baseline indicating that the resistivity of the mud filtrate (Rmf) is less than the resistivity of the water in the formation (Rw). Under these ideal conditions resistivity values of the recorded curves read as follows: SN < LN < Lat. However in the field, when Rmf < Rw experience shows that the recorded resistivity curves often yield the following responses: SN < LN = Lat.

Figure 3: Type log showing typical resistivity responses of calibrated electric log in a fresh water sand and brine sand (prepared by C.K. Ruddick, Schlumberger, modified from Hilchie, 1979.)

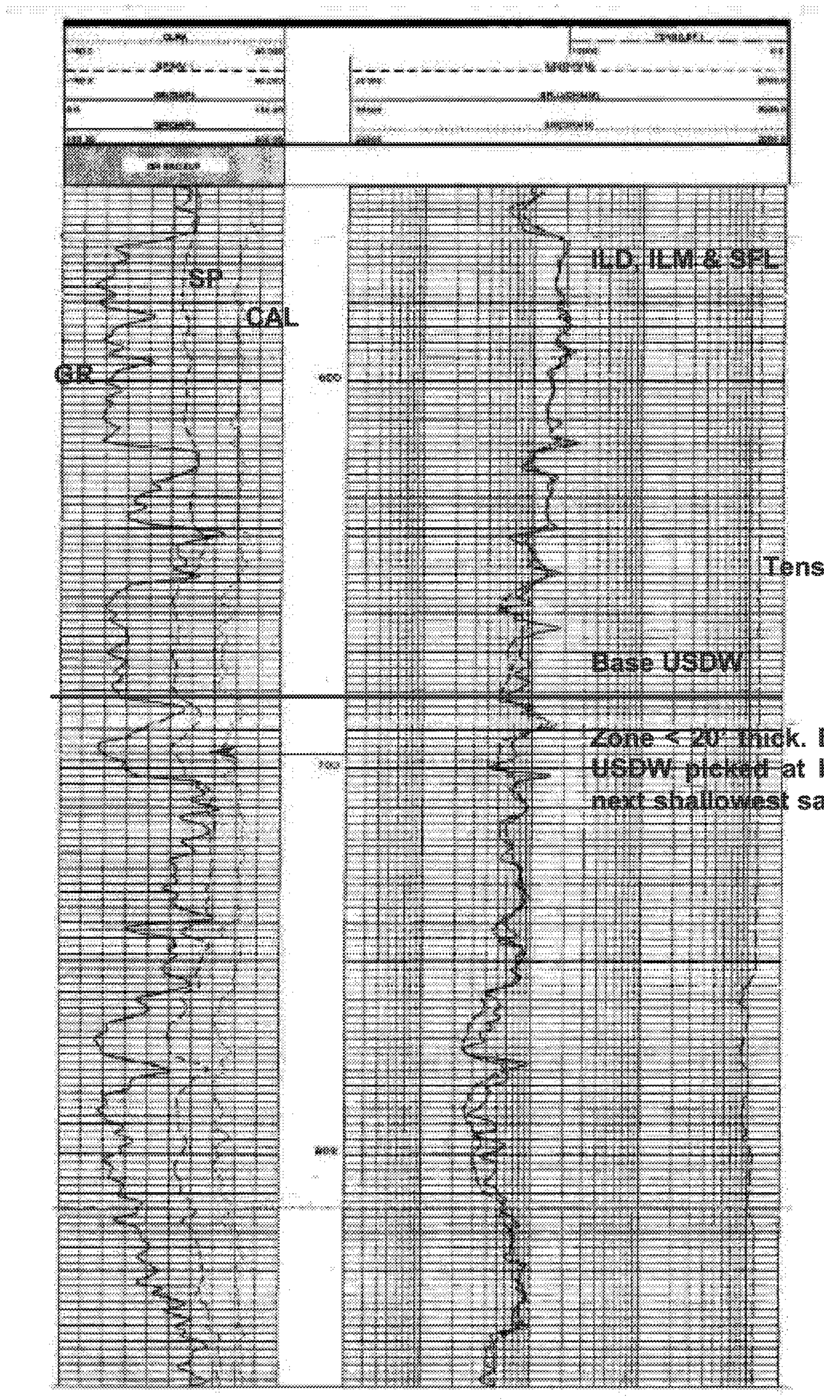


Electric log of acceptable quality recorded in 1954.

Note that SN < LN < Lateral (i.e. curve responses commensurate with type of recording). Also note back-up when curves are off scale.

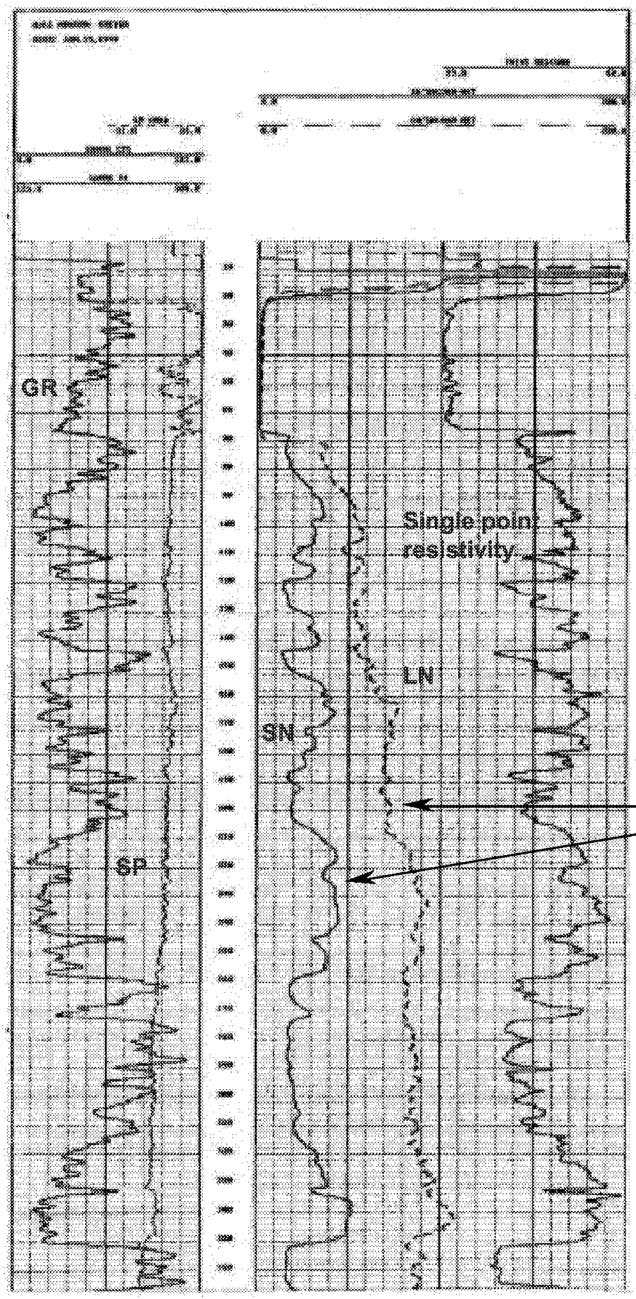
SN tool spacing = 16”
LN tool spacing = 64”
Lat tool spacing = 18’ 8” (19’ AO)

Figure 4: Example of electric log with recordings that can be used to compute R_o cut-off or estimate TDS in fresh water portion of USDW. Log recorded in Section 3-T10N-R2W, Cleveland County, OK.



Dual Induction – SFL log of acceptable quality. All curves are commensurate with type of recordings.

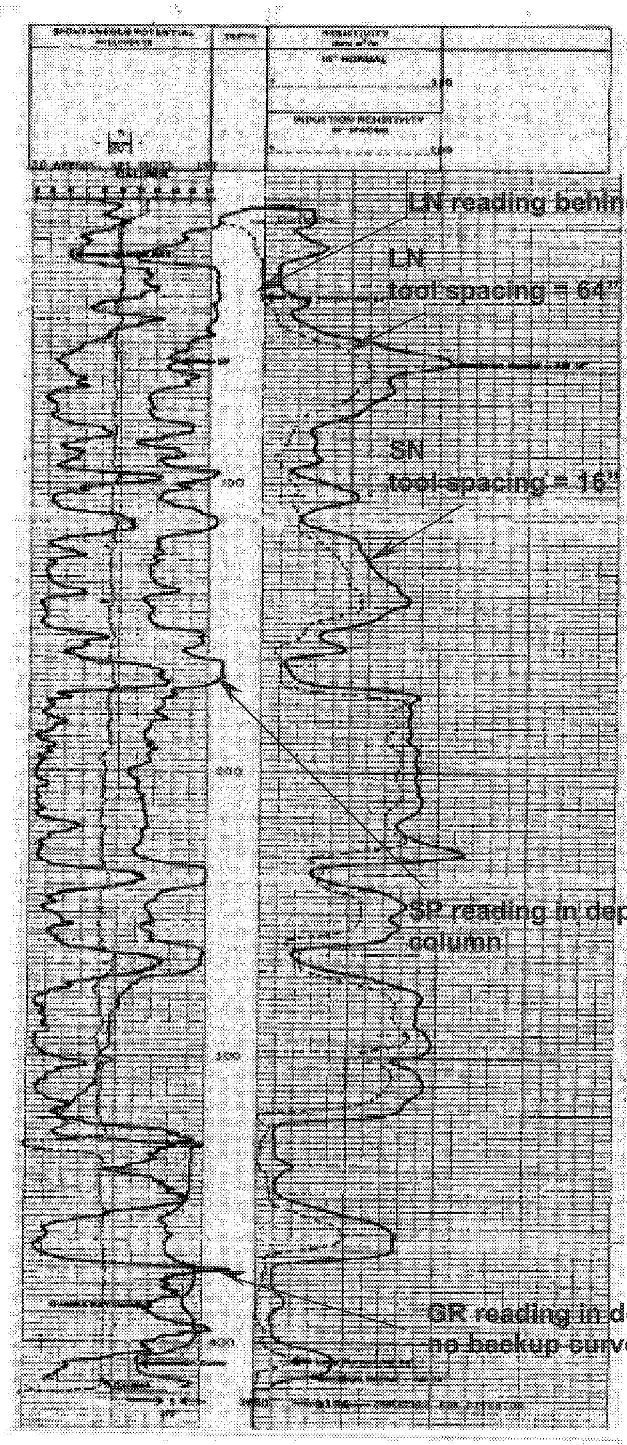
Figure 5: Example of a dual induction – shallow focused resistivity log (DIL-SFL) with gamma ray (GR), spontaneous potential (SP), caliper (CAL) and tension curves. Resistivity curves usable for picking R_o cut-off and computing TDS. Log recorded in Section 6-T13N-R1W, Oklahoma County, OK.



Excessive separation between short normal (SN) and long normal (LN) resistivity curves. Note severe drift of LN curve. Severity increases with depth.

SN tool spacing = 16”
LN tool spacing = 64”

Figure 6: Substandard log with operational problems. Log was recorded in City of Norman Test Well #8 located in Section 18-T9N-R2W, Cleveland County, OK.



Resistivity log of substandard quality. Log appears to be normal, but cannot be used to quantify R_o or TDS for the following reasons:

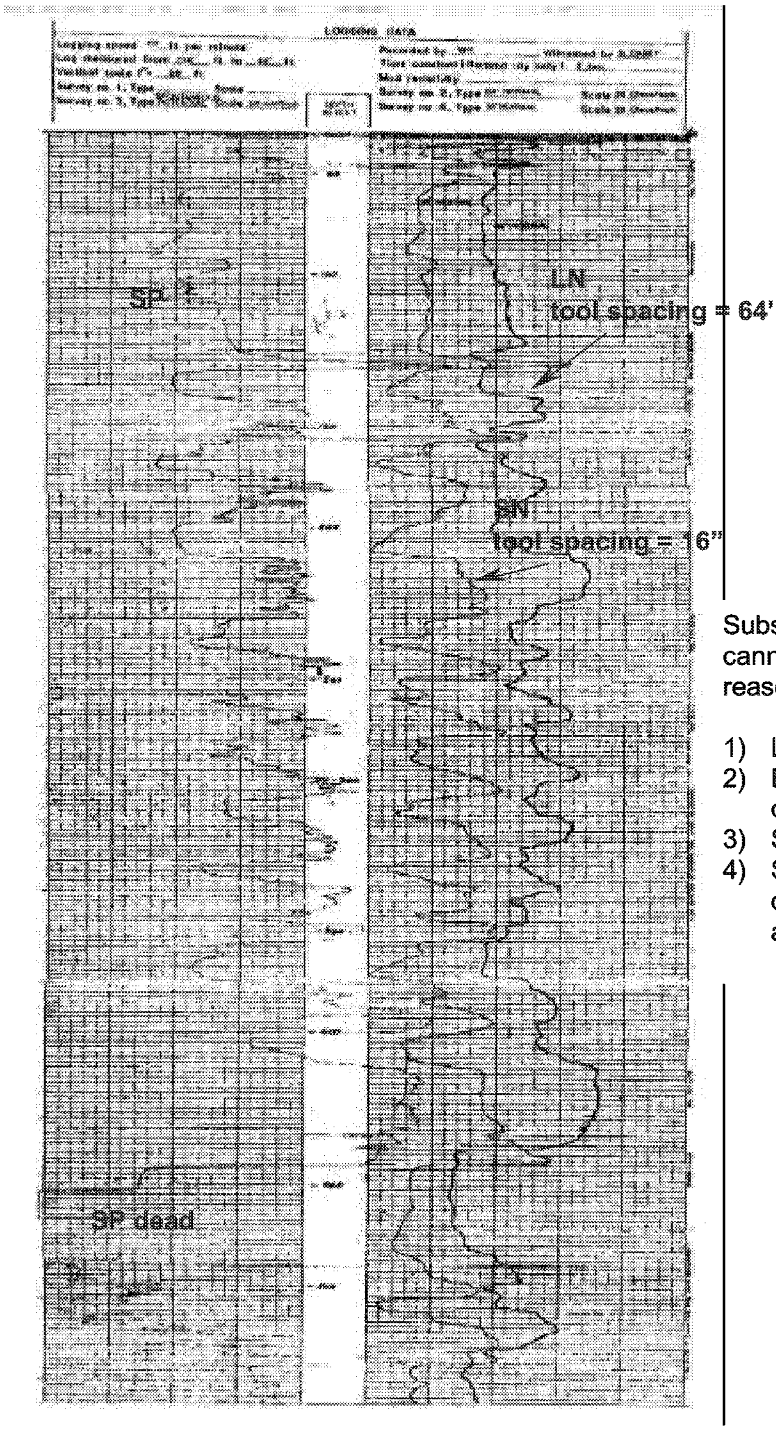
1) Log is not calibrated. LN reading behind zero at top of log.

2) SN curve reading higher than LN. However, LN should read higher than SN curve (refer to Type Log in Figure 3). This was verified by noting that the resistivity of the drilling mud (R_m) was reported on the log header to be 9 ohm-m @ 69 °F. R_m = 8 ohm-m @ 77°F. The resistivity of the formation water (R_w) in the zone from approximately 180' – 230' was measured to be 20 ohm-m @ 77 °F.

3) SP curve reading out in depth column.

4) GR curve reading out in depth column at bottom of log. GR should be recorded using backup when off scale recordings are made.

Figure 7: Log of substandard quality that cannot be used to quantify R_o or TDS. Log recorded in Section 6-T14N-R3W, Oklahoma County, OK.



Substandard log with operational problems. Log cannot be used to compute R_o or TDS for following reasons:

1) Log not calibrated.
2) Excessive separation between SN and LN curves.
3) SN reading too low (possible dampening).
4) SP drifts continually and is recorded out in depth column. Curve is dead from about 452' to approximately 550'.

Figure 8: Example of log with operational problems. Entire log is unsatisfactory, and is not even acceptable for use as a correlation tool. Log recorded in Section 1-T13N-R4W, Oklahoma County, OK.

- Fresh water: TDS < 1,000 mg/L,
- Slightly saline water: TDS = 1,000 mg/L to 3,000 mg/L,
- Moderately saline water: TDS = 3,000 mg/L to 10,000 mg/L,
- Very saline water: TDS = 10,000 mg/L to 35,000 mg/L, and
- Brine: TDS > 35,000 mg/L

The concentration of TDS may be determined by two methods. With the first method, TDS is calculated by adding the mass of the dissolved ions plus silicate (SiO_2). In this study this is referred to as "in-situ TDS". The term "in-situ" specifically refers to the TDS concentration that would be measured if the water sample had never been removed from the aquifer.

The second method requires that a known volume of water be evaporated at a specified temperature, usually, 180 °C (hereinafter referred to as TDS_{180}), then weighing the remaining solids residue. The TDS_{180} concentration will often be less than the in-situ TDS concentration because the heating that occurs when using the TDS_{180} method causes bicarbonates (HCO_3) to be converted to carbonates (CO_3) in the solid phase, while carbon dioxide (CO_2) and water (H_2O) are lost (Hounslow, 1995). This reaction is expressed by the following balanced chemical equation:

$$2HCO_3 \; ? \;\; CO_3 + CO_2 + H_2O \quad (1)$$

In consideration of the balanced equation above, the concentration of TDS residue that remains after evaporation may be calculated using the following expression:

$$TDS_{180} = \; ? \, I + SiO_2 - (\text{mg/L } HCO_3 \times 0.5082) \quad (2)$$

Where: ? I is the sum of the mass of the ions,

SiO_2 represents the mass of SiO_2,

mg/L HCO_3 is the term used to represent the concentration of HCO_3, and

0.5082 is a constant, which is determined as a function of the loss of CO_2 and H_2O as expressed in the chemical equation written above (Hounslow, 1995).

Determination of Water Conductivity

True water conductivity (C_t), often referred to as electrical conductivity (EC), specific conductivity (SC), or simply conductance, is the reciprocal of the resistance in ohms between the opposite faces of a 1-centimeter (cm) cube of an aqueous solution at a specified temperature (usually 25 °C). The units of measure for conductivity are mhos. However, because these units are large, micromhos (µmhos, i.e. mhos x 10^{-6}) are generally used. The International Unit for conductivity is siemens, which is numerically equivalent to mhos. Therefore, measurements of C_t made in the field or in the laboratory are reported in µmhos/cm, the value of which is temperature dependent (Hounslow, 1995).

C_t may be determined using two methods. The first and most common method is to measure C_t using a conductivity probe. C_t can also be calculated using the following equation (Hounslow, 1995):

$$C_t = ?\,C \times 100 \qquad (3)$$

Where: ? C is the sum of the cations in meq/L

Values of C_t, determined using the two methods, can yield different results as a consequence of any one or all of the following:

- Measurements were performed using a conductivity probe that was not calibrated,
- Some of the cation concentrations were not reported, and
- Some or all of the reported cation concentrations are inaccurate.

Validation of Water Chemical Data

The water quality data used in the study was validated to determine the accuracy and reliability of the reported results. This was facilitated through the use of a water quality data analysis and interpretation program called WATEVAL, developed by Hounslow (1995). The program was used to evaluate the accuracy of water analyses by checking the cation-anion balances, and assessing the accuracy of the reported TDS concentrations and C_t values.

Cation-Anion Balance

The cation-anion balance may be readily checked because a sample of water containing dissolved ions must be electrically neutral. This means that the sum of dissolved cations (? C) in milliequivalents per liter (meq/L) should equal the sum of dissolved anions (? A) in meq/L. The cation-anion balance is usually expressed as a percentage using the following equation:

$$\text{Balance} = (?\,C - ?\,A)/(?\,C + ?\,A) \times 100 \quad (4)$$

A margin of error of ±5% in the cation-anion balance is deemed to be acceptable because the analytical methods used to determine ion concentrations are generally incapable of yielding results with any greater precision (Hounslow, 1995). Conversely, if the balance is > ±5% the analysis is considered to be suspect. According to Hounslow (1995), the possible reasons for imbalances are:

- Laboratory error,
- Other constituents are present that were not used to calculate the balance,
- The water is very acidic and the hydrogen (H^+) ions were not included, or
- Organic ions are present in significant quantities (often indicated by colored water).

Further review of the water quality data collected for this study revealed that cation-anion imbalances were the result of laboratory error or there were not enough constituent concentrations presented in the analytical reports to allow an accurate calculation. None of the sample analyses had reported pH values below 7. There was no documentation provided with either the laboratory reports or any of the other information that was reviewed to indicate that significant quantities of organic ions were present in any of the water samples.

Only data meeting the ±5% cation-anion balance criteria was used in this study. Figure 9 is a printout produced by WATEVAL showing chemical data, which meets the cation-anion balance criteria. Figure 10 is an example of water quality data that did not meet the balance criteria.

TDS and Water Conductivity

Validation of TDS and C_t data was performed only for those analyses that had met the cation-anion balance criteria. This was accomplished by using WATEVAL to compute values for in-situ TDS, TDS_{180} and C_t as a function of the ion concentrations that are entered into the program. The computations made by WATEVAL were performed using expression *(1)*, *(2)*, *(3)* and *(4)* presented above. The values computed by WATEVAL were compared to the TDS and C_t values entered into the program from the laboratory reports. Differences between the computed and input values were reported in percent.

Sample DCN2-2

TempC =	0.0	pH =	8.1
TDS =	310.0	COND =	0.0
HARD =	150.0	DENS =	0.0
x-cor =	0.0	y-cor =	0.0
Units =	mg/L	rock =	0.0

	mg/L	mmole/L	meq/L	% meq/L
Na+	53.0	2.3052	2.3052	42.6
K +	1.5	0.0384	0.0384	0.7
Ca++	30.0	0.7485	1.4970	27.7
Mg++	19.0	0.7815	1.5630	28.9
Cl-	22.0	0.6205	0.6205	10.9
SO4--	21.0	0.2186	0.4372	7.6
HCO3-	281.0	4.6053	4.6053	80.5
CO3--	1.0	0.0167	0.0333	0.6
SiO2	0.0	0.0000	0.0000	0.0
Li+	0.0	0.0000	0.0000	0.0
Sr++	0.0	0.0000	0.0000	0.0
Ba++	0.2	0.0017	0.0035	0.1
Fe++	0.0	0.0000	0.0000	0.0
NO3-	0.7	0.0113	0.0113	0.2
F-	0.2	0.0100	0.0100	0.2
Br-	0.0	0.0000	0.0000	0.0
B	0.0	0.0000	0.0000	0.0

LANGELIER INDEX = 0.17 SAR = 1.9
Conductivity = 0 umho Est. Cond. = 541 umho

Analytical checks and comparisons

Sum cations = 5.4071 Sum anions = 5.7177 — Bm OK
BALANCE = -2.79 %

TDS entered = 310 mg/L
TDS calc = 430 mg/L TDS(180) calc = 287 mg/L
Entered TDS - TDS(calc) diff= -38.6 % Entered TDS - TDS(180) diff= 7.5 %

Conductivity = 0 umho
TDS(entered)/Cond ratio = 0.00 Usual range = 0.55 to 0.75
TDS(calc)/Cond = 0.00 Usual range = 0.55 to 0.75
Conductivity/Sum-cations = 0 Usual range = 90 - 110

Entered and calculated density
Meas. Density = 0.0000 Calc. Density = 1.0003

Entered and calculated hardness
Meas. hardness= 150.0 mg/L CaCO3 Calc. hardness= 153.1 mg/L CaCO3

Element ratios
Na/(Na+Cl) = 78.8 % Usually > 50%

Ca/(Ca + SO4) = 77.4 % Usually > 50%
K/(Na + K) = 1.6 % Usually < 20%

Mg/(Mg+Ca) = 51.1 % Usually < 40%

Carbonate/bicarbonate at pH = 8.06
Meas HCO3 = 281.0 mg/L Meas CO3 = 1.0 mg/L
Calc HCO3 = 279.6 mg/L Calc CO3 = 1.0 mg/L

Figure 9: WATEVAL printout showing chemical data meeting the cation-anion balance criteria. Note that TDS_{180} did not fall within ±5% acceptability limits. Data from Deer Creek Water Corp. Neal #2 Test Well location in Section 17-T14N-R3W, Oklahoma County, OK.

```
                         Sample DCN2-3
TempC  =       0.0                       pH     =       8.5
TDS    =     310.0                       COND   =       0.0
HARD   =      45.0                       DENS   =       0.0
x-cor  =       0.0                       y-cor  =       0.0
Units  =   mg/L                          rock   =       0.0

              mg/L     mmole/L    meq/L     % meq/L
Na+           82.0     3.5666     3.5666    79.2
K +            1.1     0.0281     0.0281     0.6
Ca++           9.3     0.2320     0.4641    10.3
Mg++           5.4     0.2221     0.4442     9.9
Cl-           15.0     0.4231     0.4231     7.2
SO4--         31.0     0.3227     0.6454    11.0
HCO3-        288.0     4.7201     4.7201    80.3
CO3--          2.0     0.0333     0.0667     1.1
SiO2           0.0     0.0000     0.0000     0.0
Li+            0.0     0.0000     0.0000     0.0
Sr++           0.0     0.0000     0.0000     0.0
Ba++           0.1     0.0010     0.0020     0.0
Fe++           0.0     0.0000     0.0000     0.0
NO3-           0.6     0.0095     0.0095     0.2
F-             0.3     0.0132     0.0132     0.2
Br-            0.0     0.0000     0.0000     0.0
B              0.0     0.0000     0.0000     0.0

    LANGELIER INDEX =        0.12     SAR              =        5.3
    Conductivity    =        0 umho   Est. Cond.       =      451 umho

                  Analytical checks and comparisons

Sum cations     =      4.5051          Sum anions      =     5.8779
                                       BALANCE         =    -13.22 %
                  TDS entered     =   310         mg/L
TDS calc        =      435 mg/L        TDS(180) calc =        288 mg/L
Entered TDS - TDS(calc) diff= -40.3 %  Entered TDS - TDS(180) diff=   7.0 %

                         Conductivity =  0   umho
TDS(entered)/Cond ratio      =  0.00   Usual range    = 0.55 to 0.75
TDS(calc)/Cond               =  0.00   Usual range    = 0.55 to 0.75
Conductivity/Sum-cations     =  0      Usual range    = 90 - 110

                  Entered and calculated density
Meas. Density =    0.0000              Calc. Density =      1.0003

                  Entered and calculated hardness
Meas. hardness=    45.0 mg/L CaCO3     Calc. hardness=     45.5 mg/L CaCO3

                            Element ratios
Na/(Na+Cl)      =     89.4 %           Usually > 50%

Ca/(Ca + SO4) =      41.8 %            Usually > 50%
K/(Na + K)      =      0.8 %           Usually < 20%

Mg/(Mg+Ca)      =     48.9 %           Usually < 40%

                         Carbonate/bicarbonate at pH =  8.49
Meas HCO3       =    288.0    mg/L     Meas CO3        =      2.0   mg/L
Calc HCO3       =    283.8    mg/L     Calc CO3        =      2.6   mg/L
```

Figure 10: WATEVAL printout showing chemical data not meeting the cation-anion balance criteria. Note that TDS_{180} did not fall within ±5% acceptability limits. Data from Deer Creek Water Corp. Neal #2 Test Well located in Section 17-T14N-R3W, Oklahoma County, OK.

As with the cation-anion balance check, the reported values of TDS should be within ±5% of the computed concentration for either in-situ TDS or TDS_{180} (Hounslow, 1995). None of the reported TDS concentrations were within 5% of either the computed in-situ TDS or TDS_{180} concentrations. An examination of the TDS analysis checks indicated that the input values were always closest to the computed TDS_{180} values, indicating that the TDS concentrations presented in the laboratory reports had been determined using the evaporation method.

Comparisons between the reported and computed values of C_t were also made using the ±5% criteria. As with the TDS data, none of the reported C_t values fell within 5% of the computed values.

TDS and Conductivity Values Representative of Water Chemical Data

Upon completion of the validation process, it was determined that the in-situ TDS and C_t values computed by WATEVAL were the most representative of the water chemical data. The basis for this decision was as follows:

- TDS and C_t were not consistently reported in any of the chemical data. Reported values of either one parameter or the other, but not both, were provided.
- TDS concentrations that were determined using the evaporation method were not considered to be representative of in-situ ground water chemistry. This is due to the loss of CO_2 and H_2O from the heating that occurs during evaporation, which caused the TDS_{180} concentrations to be much lower than the in-situ TDS concentrations.
- Validation of the reported water quality data revealed that the differences between input TDS_{180} and computed TDS_{180} concentrations exceeded the ±5% accuracy criteria. Consequently, the reported TDS_{180} concentrations were suspect. The same was true for the input and computed values of C_t.
- The values for in-situ TDS and C_t are directly proportional to the concentrations of dissolved ions in solution. Since only data meeting the ion balance criteria was used, the computed values of in-situ TDS and C_t were deemed to be representative of ground water chemistry in the USDW.
- Open-hole resistivity logs represent records of measurements of in-situ formation petrophysical properties and ground water chemistry. In order to understand the relationship between recorded formation resistivities and measured ground water quality data, the water chemistry data must be reflective of in-situ environmental conditions.

QUANTIFICATION OF WATER QUALITY USING RESISTIVITY LOGS

Formation resistivity measurements are an integral and vital part of most logging programs for oil and gas exploration. The application of open-hole resistivity logs to mapping the subsurface and evaluating the production potential of petroleum reservoirs is widely understood in the oil and gas industry.

With a few adjustments, open-hole resistivity logs can also be of considerable value for characterizing aquifer physical conditions and quantifying ground water chemical parameters. According to Alger (1966), the interpretation of resistivity logs in fresh water formations can in some ways be simpler than in petroleum-related applications because:

- In ground water formations the working depths are typically shallow in comparison to those that are encountered in oil and gas wells. Therefore, the affects of the borehole environment have less of an impact on the resistivity recording devices, which makes interpretation of the recorded responses easier.

- The porosities are generally high, particularly in shallow fresh water sands. Variations in porosity between formations encountered in a single well and between wells in the same general locale are usually not large enough to significantly influence formation resistivity values. Consequently, the determination of porosity, so important in the interpretation of logs in petroleum work, is less important for evaluation of fresh water in sandstone aquifers.

THEORETICAL CONSIDERATIONS

Some of the chemical parameters that are used to characterize ground water quality can be estimated using open-hole resistivity logs through the use of a formation factor (F). F represents the empirical ratio between open-hole resistivity log responses and resistivity of the formation water. Based on the work of Jones and Buford (1951), Turcan (1966) expressed this ratio using the following equation:

$$F = R_o/R_w \quad (5)$$

Where: R_o is the resistivity in ohm-meters (ohm-m) of a 100% water saturated formation,

R_w is the resistivity in ohm-m of the formation water contained in the pores

R_w can be determined when F and R_o are known. R_w is inversely proportional to C_t in µmhos/cm in accordance with the following expression:

$$R_w \text{ in ohm-m} = 10{,}000/C_t \quad (6)$$

PETROPHYSICAL AND CHEMICAL PROPERTIES

The log interpretation techniques that are employed for quantifying fresh ground water conditions, while relatively simple, must be used cautiously. Unless the petrophysical and chemical conditions that influence recorded log responses are well understood, grossly inaccurate results can occur.

Porosity

In petroleum work, the petrophysical property considered in all basic log calculations is porosity. However, when working in porous sandstone formations containing fresh to moderately saline water, the usual relationship between F and porosity (F):

$$F = a/F^{m} \quad (7)$$

Where: a is the tortuosity factor, which is a function of the complexity of the path the fluid must travel through a rock. Values most generally range from 0.62 to 1.0 depending on the type of lithology (i.e. sandstone or limestone).

m is the cementation exponent, which depending on formation lithology, generally ranges between 2.0 and 2.15.

is not constant. Instead, the value of F is typically influenced more by changes in R_w and grain size (Alger, 1966).

To determine if changes in formation porosity were an important consideration in this investigation, a few porosity logs from wells located within the study unit were identified and reviewed. Porosity data from the logs are presented in Figure 11. The data illustrate that formation porosities of Permian sandstones across the study unit range from 23 percent (%) to 35%.

Close examination of the logs showed that formation porosity gradually decreased with depth. The lowest porosities were generally observed to be associated with sandstone bodies, which were initially believed to be located near the bottom or below the USDW, because their formation resistivities were in the 1.0 ohm-m to 3.0 ohm-m range. In sandstones exhibiting higher resistivities (i.e. > 3 ohm-m), porosity averaged around 30%. A qualitative review of the

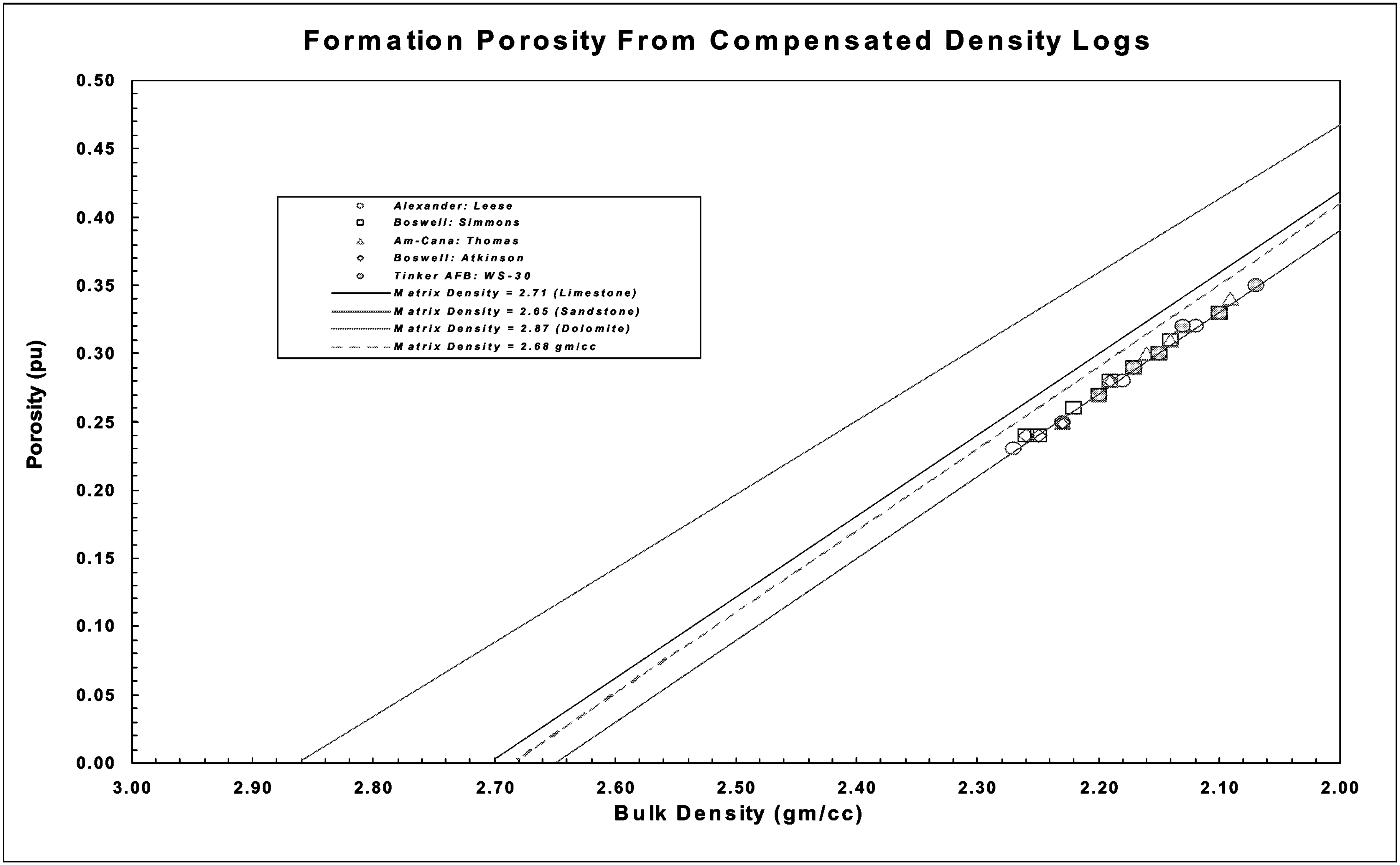


Figure 11: Cross-plot of porosity versus bulk density. Data obtained from bulk density logs recorded in five wells located in the study unit. (Adapted from Schlumberger log interpretation charts, 1972)

log and water chemical data indicated that as formation resistivities increased formation water became increasingly fresh. Therefore, significant changes in formation resistivity occurring in zones within the USDW were not considered to be caused by large fluctuations in porosity.

Grain Size

Variations in the value of F will occur in response to changes in grain size. Alger (1966) showed that as grain size decreases so does the value of F. He also demonstrated that the value of F will begin to decrease rapidly as the value of R_w approaches 10 ohm-m. Therefore, when working in sandstones saturated with fresh water, the potential effects of grain size on the value of F should be considered.

Surface Conductance

In fresh water formations R_w values are high. Under these conditions the recorded formation resistivities are influenced by surface conductance, which in accordance with the relationships expressed in equation *(5)*, will affect the value of F.

Surface conductance is defined as the electrical conductance that occurs at the surfaces of solid crystalline materials when they are exposed to aqueous solutions (SPWLA, 1984). In simple terms, this means that when the pore spaces in a formation are filled with fresh water, the electrical current that is induced into the formation by the logging tool will tend to travel across grain surfaces and through conductive interstitial clays instead of through the resistive formation water.

According to Alger (1966), the magnitude of surface conductance is related to changes in the concentration of TDS and grain size, and will increase in response to:

- Decreases in the concentration of TDS and the corresponding decreases in fluid conductivity, and
- Increases in grain size and the corresponding increases in the amount of surface area that is exposed to the saturant solution.

Ground Water Chemistry

When using resistivity logs to estimate TDS, it is necessary to be knowledgeable about the family of ions that are present in the ground water. In petroleum work, brine is usually encountered and the concentration of TDS is in excess of 35,000 mg/L. Under these conditions sodium chloride (NaCl) is most generally the predominant dissolved mineral salt. In fresh formation waters, dissolved ions other than Na and Cl become important (Schlumberger, 1989), meaning that the methods so often used in petroleum work for estimating R_w may not be applicable. The reason for this is that the *activity* of a solution containing predominantly dissolved Na and Cl is very different from one where other ions such as Ca, Mg, K, HCO_3 and SO_4 are present. Hounslow (1995) explains *activity* this way:

> *"In water chemistry it is often desirable to know whether a mineral will dissolve in, or precipitate from, a particular solution. As a solution becomes increasingly concentrated with ions, they will interact with each other such that some may no longer be present as separate ions. Thus, only a portion of the ions will act in a predictable way. This predictable quality is called activity."*

When working in fresh water formations R_w should be determined empirically to account for influences caused by variations in the type and relative proportions of ion species that are present in solution.

CHARACTERIZING AND MAPPING THE BASE OF THE USDW

To accurately identify and map the base of the USDW it was necessary to derive a formation resistivity value, which would most closely approximate an in-situ TDS concentration of 10,000 mg/L. A discussion of the methodology used to characterize and map the base of the USDW is provided below.

CLASSIFICATION OF WATER TYPES

Because variations in the type and relative proportions of ion species that are present in solution influence R_w, water chemical data was classified by water type. This was accomplished using Piper diagrams, which were generated by WATEVAL. Classification of water types was determined based on where major cation and anion species plotted within the diamond shaped figure of the diagram. Each quadrant of the diamond represented a general water type as follows:

- Upper quadrant: Ca-Mg-Cl-SO_4 water
- Right quadrant: Na-Cl-SO_4 water
- Lower quadrant: Na-HCO_3 water
- Left quadrant: Ca-Mg-HCO_3 water

Figure 12 is a Piper plot where all of the water chemical analyses from a single test well were plotted and classified according to water type.

EMPIRICAL RELATIONSHIP BETWEEN IN-SITU TDS AND C_t

To compute the R_o cut-off value, it was necessary to establish the relationship between in-situ TDS and C_t as a function the water type. Examination of the water quality data and validation results indicated that only in-situ TDS concentrations above 1,000 mg/L could be used to derive the R_o cut-off, because important differences in water type(s) occurred above and below this value. Ca-Mg-Cl-SO_4 and Na-Cl-SO_4 waters were found to be exclusively associated with in-situ TDS concentrations above 1,000 mg/L. Concentrations less than 1,000 mg/L TDS were represented by Ca-Mg-HCO_3 and Na-HCO_3 waters. As a result, principal differences in water chemistry were related to the presence or absence of either dissolved Cl-SO_4 or HCO_3. Dissolved Ca-Mg or Na cations were present regardless of TDS concentration.

Six sets of chemical data were identified where the in-situ TDS concentrations were greater than 1,000 mg/L (Table 1). Five of the six data sets were comprised of chemical data that had been collected at municipal test well

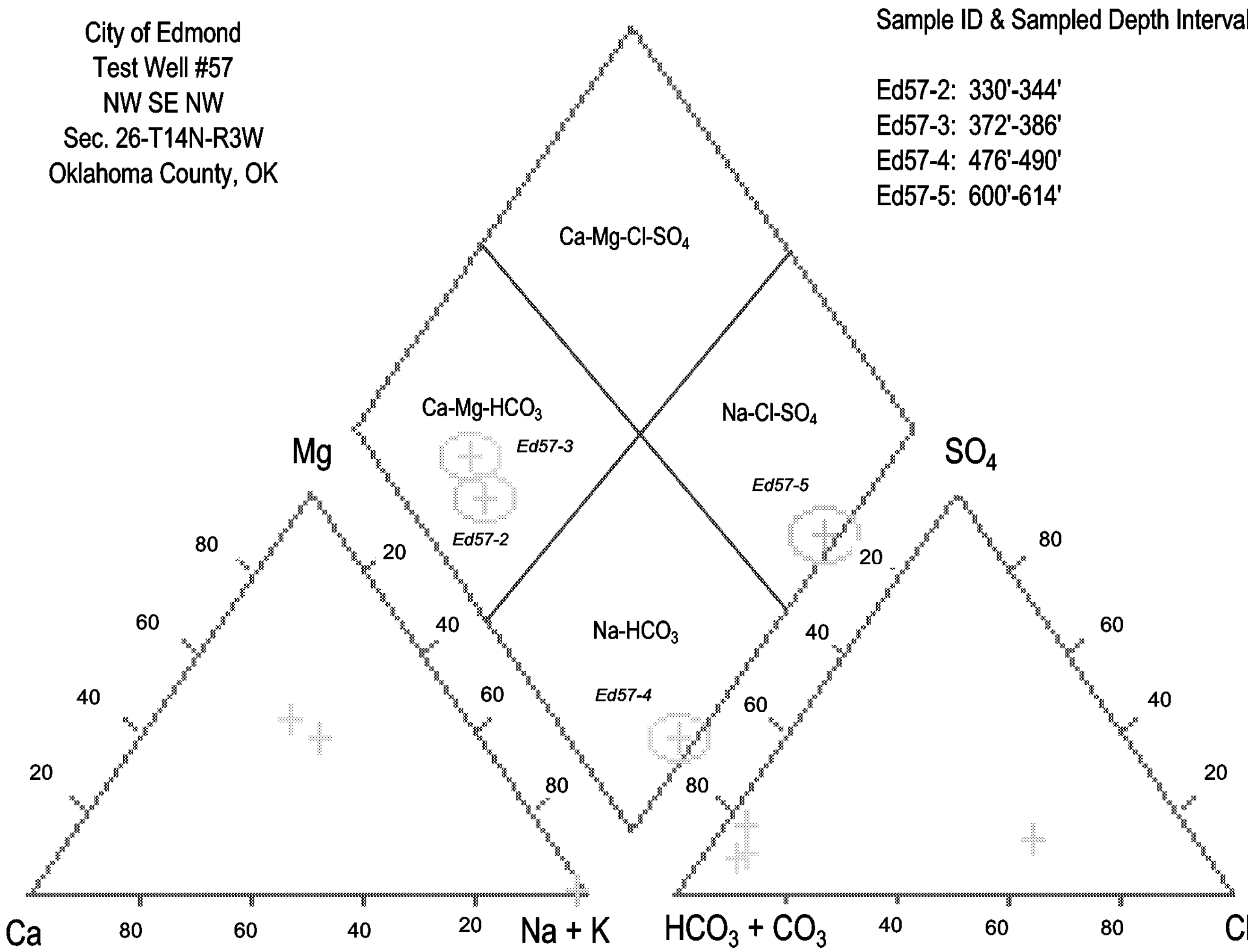


Figure 12: Piper diagram showing variation in water types encountered in a test well in North-Central Oklahoma County. Percentages of ions/ionic pairs are in total milliequivalents per liter.

CONTROL DATA USED TO ESTABLISH R_o CUT-OFF CORRESPONDING TO TDS = 10,000 mg/l (TDS > 1,000 mg/L)

Test Well Owner: Well Identifier Spot Location, Sec.-Twp-Rge County	Sample ID	Test Interval (Ft)		Fm. Temp. (°F)	R_o at Fm. Temp. (ohm-m)	R_o at 77° F (ohm-m)	Ct at 77° F (µmhos/cm)	In-situ TDS (mg/L)	R_w at 77° F (ohm-m)	Formation Factor
		from	to							
City of Norman: Westport Golf Club Test #1 SW NE, 26-09N-03W Cleveland County	Wport5	408	418	64	40	34	1613	1340	6.20	6.45
	Wport6	326	336	64	20	17	2571	2029	3.89	5.14
City of Edmond: Test Well #1 SW SW NE, 03-13N-03W Oklahoma County	Ed1-1	650	673	67	17	15	3654	2563	2.74	6.21
	Ed1-2	590	611	66	40	35	1864	1451	5.36	7.46
Gaillardia: Test Well #1 NW NW SW SE, 10-13N-04W Oklahoma County	Gal1-1	254	277	63	12	10	4205	3041	2.38	5.05
	Gal1-2	323	346	64	18	15	2687	1935	3.72	4.84
Gaillardia: Test Well #3 NE NW NW, 10-13N-04W Oklahoma County	Gal3-2	327	350	64	15	13	3150	3226	3.17	4.73
	Gal3-3	411	434	65	28	24	1768	1291	5.66	4.95
City of Edmond: Test Well #57 NW SE NW, 26-14N-03W Oklahoma County	Ed57-5	600	614	67	17	15	2605	1748	3.84	4.43
USGS: Test Well NOTS 5 NE NE SE, 03-08N-03E Pottawatomie County	N5-131	127	155	61	5	4	13986	9801	0.72	6.99
	N5-183	169	197	62	7	6	10299	7454	0.97	7.21
						Formation Factor (Mean Value)				5.77

Table 1: Control data used to establish R_o cut-off corresponding to 10,000 mg/L in-situ TDS

locations and a golf course. One set of chemical data was derived from USGS Open-File Report 91-464 (Schlottman and Funkhouser, 1991).

With the exception of the USGS data, the other data sets were derived from test wells located within the study unit. TDS data selected from the USGS open-file report had been collected from two water-bearing zones encountered in USGS Test Well NOTS 5, located east of the study unit in Pottawatomie County, Oklahoma. Water quality data from the NOTS 5 well was accepted for use based on the following criteria:

- TDS concentrations approached the 10,000 mg/L cut-off.
- Descriptions provided by Schlottmann and Funkhouser (1991) indicated that the intervals tested in the well had evaluated Permian sedimentary units, which were recognized as belonging to the Central Oklahoma Aquifer hydrogeologic system.

The empirical association between in-situ TDS and C_t was established by graphically comparing their values using a scatter diagram (Figure 13). A simple straight line fit through the plotted data revealed a well-defined linear relationship. The correlation coefficient (R^2 = 0.9887) showed a high degree of correlation, and indicated that in-situ TDS could be accurately estimated using the following linear expression:

$$\text{In-situ TDS} = (0.6923 \times C_t) + 215.49 \qquad (8)$$

DERIVATION OF C_t CORRESPONDING TO 10,000 mg/L TDS

The parameter used to relate formation resistivity to in-situ TDS is C_t, which by definition is reported at 77 °F (25 °C). Thus, a C_t value corresponding to a TDS concentration of 10,000 mg/L was determined by rearranging equation *(8)* as follows:

$$C_t = (10{,}000 - 215.49)/0.6923 \qquad (9)$$

$$C_t = 14{,}133 \ \mu\text{mhos/cm}$$

Having determined a value for C_t that was consistent with a TDS concentration of 10,000 mg/L, the stage was set for the R_o cut-off value to be determined.

INFLUENCE OF TEMPERATURE ON RESISTIVITY

In all log interpretation work temperature becomes an important consideration because it directly impacts the value of R_o and R_w. Consequently, before

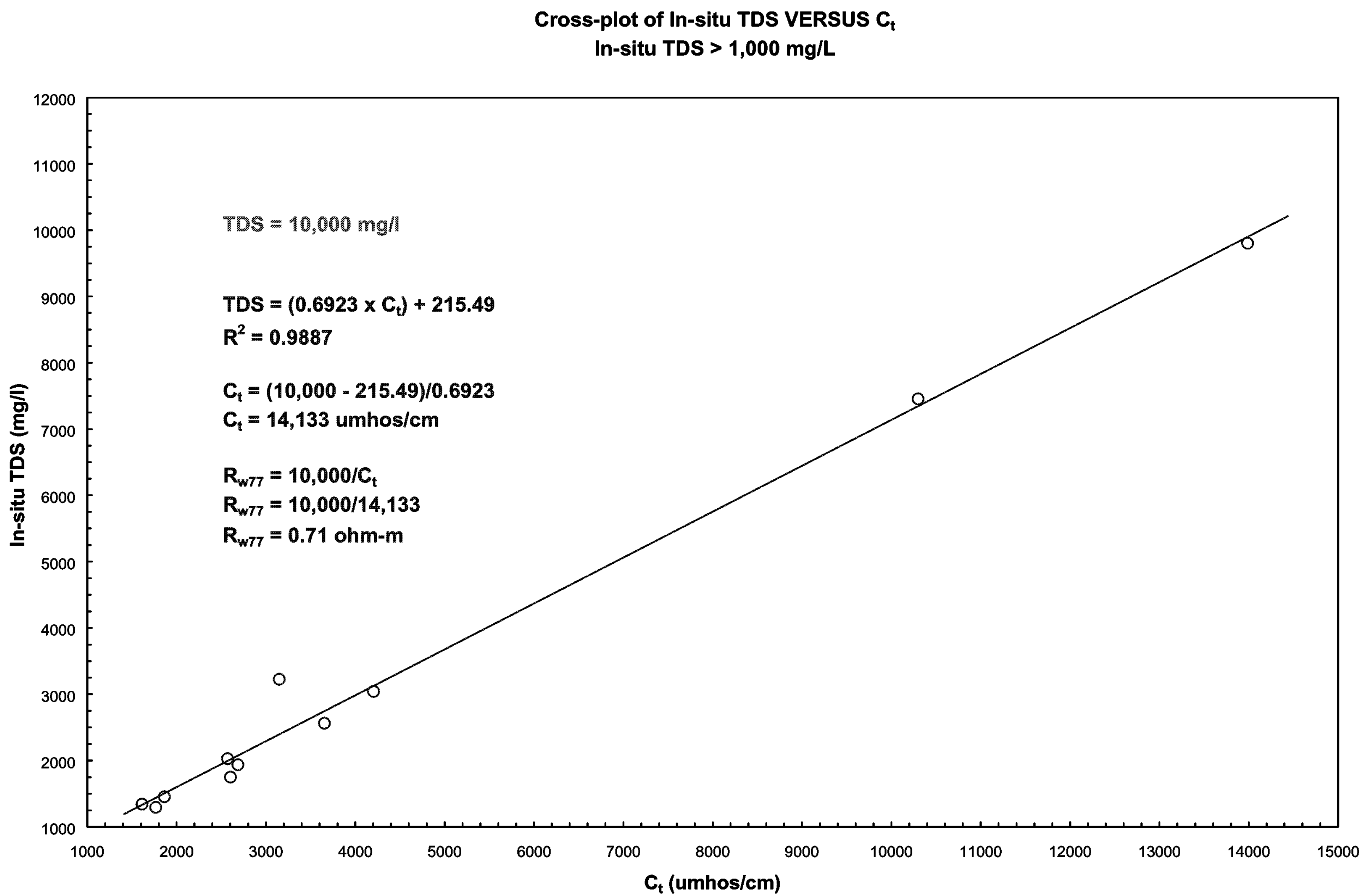


Figure 13: Scatter diagram showing empirical relationship between in-situ TDS and C_t

attempting to compute F, R_o values had to be temperature corrected to 77 °F (25 °C).

In order to make the necessary temperature correction it was first necessary to determine formation temperature. Formation temperature was calculated using the following linear regression equation (Asquith, 1982):

$$T_{fm} = T_g \times D + T_s \quad (10)$$

Where: T_{fm} = formation temperature in °F

T_g = Temperature gradient (i.e. slope of regression line)

D = depth

T_s = mean annual surface temperature (60 °F)

Computation of formation temperature requires that a temperature gradient for the area be determined. This was accomplished by rearranging equation *(10)* and solving for T_g. The data used to compute T_g was derived from temperature and depth data reported on the log headings of wells located near the center of each township in the study unit. The value of T_g was calculated as the mean of all the individual gradients, which was 0.0120 °F per foot (°F/ft).

Formation temperature for each test interval listed in Table 1 was computed and the R_o values were temperature corrected using Arp's formula (Asquith, 1982):

$$R_2 = R_1 \times (T_1 + 6.77)/(T_2 + 6.77) \quad (11)$$

Where: R_2 represents the temperature corrected resistivity,

R_1 represents resistivity other than the temperature corrected resistivity,

T_1 is the temperature at which R_1 was measured (i.e. formation temperature), and

T_2 is the temperature to which R_2 is corrected (i.e. 77 °F).

COMPUTATION OF FORMATION FACTOR

As shown by equation *(5)*, the value of F and R_w are dependent on the value of R_o. Therefore, to establish the R_o cut-off, it was critical that the log resistivity data be accurate.

Examination of the resistivity logs recorded in the test wells (Table 1) revealed that the recording devices had not been properly calibrated. As a result, the logs were considered unreliable. To resolve this problem, calibrated resistivity logs recorded in offsetting oil and gas wells were used to determine formation resistivities in the zones that were evaluated in the test wells.

While the recorded resistivities in the test wells were unsatisfactory for making computations, the basic character of the curves was such that they could be used as a correlation tool. Therefore, correlating the test well logs with the offset well logs permitted reliable formation resistivities to be determined.

Once the formation resistivities of the test intervals had been determined, they were temperature corrected to 77 °F, thus allowing F to be computed using equation *(5)*. A quick review of Table 1 reveals that different values for F were calculated for each test interval. This was interpreted to be associated with changes in rock fabric (grain size) based on the following evidence:

- Published studies suggest that the sediments that comprise the USDW were deposited in a fluvial-deltaic system. Variations in grain size are characteristic of such an environment, meaning that changes can occur, not only between wells but also within a single wellbore.
- Porosity logs indicated that the porosities in water-bearing sandstones above the base of the USDW were reasonably constant, averaging around 30%, and
- The potential affects associated with variations in water type were minimized as a result of using only control data having TDS concentrations in excess of 1,000 mg/L.

A mean F value was computed to compensate for the affects on its value related to changes in grain size (Table 1).

COMPUTATION OF R_o CUT-OFF

The steps involved in computing the R_o cut-off are presented in Figure 14. It should be noted that three temperature-corrected R_o cut-off values were produced. The baseline R_o cut-off value (R_{o77}), equal to 4.1 ohm-m, was temperature-corrected to 77 °F (i.e. standard temperature). The two other R_o cut-off values were computed to evaluate the impact of fluctuations in formation temperature caused by changes in depth to the base of the USDW. Corrected R_o values were determined for both a minimum and maximum anticipated depth to the base of the USDW, so that the impact of temperature could be evaluated at the two temperature extremes.

ESTABLISHMENT OF R_o CUT-OFF FOR WATERS CHARACTERIZED AS SLIGHTLY TO MODERATELY SALINE (TDS = 1,000 mg/l to 10,000 mg/l)

Formation resistivity cut-off determined at standard temperature of 77° F

TDS = (0.6923 x C_t) + 215.49
10,000 - 215.49 = 0.6923 x C_t
C_t = (10,000 - 215.49)/0.6923
C_t = 14,133 umhos/cm

R_{w77} = 10,000/C_t
R_{w77} = 10,000/14,133
R_{w77} = 0.71 ohm-m

R_{o77} = F x R_{w77}
R_{o77} = 5.77 x 0.71
R_{o77} = 4.1 ohm-m

TDS = In-situ total dissolved solids concentration (mg/l)
C_t = Formation water conductivity (umhos/cm)
R_{w77} = Formation water resistivity at standard temp. of 77° F (ohm-m)
R_{o77} = Formation resistivity at stanadard temp. of 77° F (pores 100% water-filled)
F = Formation Resistivity Factor (dimensionless)

Adjustment of formation resistivity cut-off to formation temperature at greatest anticipated depth to base of USDW

FMT_{max} = (T_g x D_{max}) + T_s
FMT_{max} = (0.0120 x 1200) + 60
FMT_{max} = 74.4° F

*R_{oMAX} = R_{o77} x (77 + 6.77)/(FMT_{max} + 6.77)
R_{oMAX} = 4.1 x (83.77)/(81.17)
R_{oMAX} = 4.2 ohm-m

FMT_{max} = Formation temperature at anticipated maximum depth to base of USDW
T_g = Temperature gradient (0.0120° F/ft.)
D_{max} = Maximum anticipated measured depth to base of USDW (1,200 ft.)
T_s = Mean annual surface temperature (°F)
R_{oMAX} = Formation resistivity adjusted for maximum formation temperature

Adjustment of formation resistivity cut-off to formation temperature at shallowest anticipated depth to base of USDW

FMT_{min} = (T_g x D_{min}) + T_s
FMT_{min} = (0.0120 x 250) + 60
FMT_{min} = 63.0° F

*R_{oMIN} = R_{o77} x (77 + 6.77)/(FMT_{min} + 6.77)
R_{oMIN} = 4.1 x (83.77)/(69.77)
R_{oMIN} = 4.9 ohm-m

FMT_{min} = Formation temperature at anticipated minimum depth to base of USDW
T_g = Temperature gradient (0.0120° F/ft.)
D_{min} = Minimum anticipated measured depth to base of USDW (250 ft.)
T_s = Mean annual surface temperature (°F)
R_{oMIN} = Formation resistivity adjusted for minimum formation temperature

***Arp's formula: $R_2 = R_1 \times (T_1 + 6.77)/(T_2 + 6.77)$**

Figure 14: Steps involved in the computation of the R_o cut-off = 10,000 mg/L TDS

Using the baseline cut-off value (i.e. 4.1 ohm-m) as a guide, the minimum and maximum anticipated depth to the base of the USDW was determined by examining the logs. The minimum and maximum anticipated depths to the base of the USDW were 250 feet and 1,200 feet respectively. The R_o value (R_{oMIN}) corresponding to the minimum depth was calculated to be 4.9 ohm-m, while the maximum value (R_{oMAX}) was 4.2 ohm-m. This difference in extreme values was considered negligible.

An additional check was made to determine what effect, if any that computation of a mean value for F would have on the cut-off. Using the highest and lowest values of F listed in Table 1 (i.e. F = 7.46 and 4.43), high and low R_{o77} values were calculated. The cut-off high was determined to be 5.3 ohm-m and the low was 3.1 ohm-m. These excursions from the baseline cut-off (i.e. 4.1 ohm-m) were considered to be acceptable for the following reasons:

- Differences in formation resistivities recorded on the logs often cannot be determined more precisely, particularly if the resistivity curves were presented in a linear scale format.
- Slight differences in recorded formation resistivities can occur in response to variations in borehole environmental conditions and dimensions between wells.

In consideration of the possible extreme values, the R_o cut-off was, for mapping purposes, conservatively set at 4.0 ohm-m.

CRITERIA USED TO IDENTIFY THE BASE OF THE USDW ON LOGS

Open-hole resistivity logs recorded in 853 wells in Cleveland, Logan and Oklahoma Counties were used to map the base of the USDW. Using the 4.0 ohm-m R_o cut-off, the base of the USDW was identified and mapped using the following criteria.

- Only water-bearing zones greater than or equal to 20 feet in thickness were evaluated because resistivity logs of different vintages were used to pick the base of the USDW. Twenty feet was considered to be optimal, because as zone thickness decreases, the properties of adjacent formation beds begin to impact the recorded resistivity measurements.
- Water bearing zones less than 20 feet in thickness were considered to be impractical to protect, because as thinning occurs corresponding reductions in yield would very likely take place. In addition, a general degradation in the quality of ground water occurs towards the base of the USDW.

- If resistivities less than the 4.0 ohm-m cut-off occurred anywhere in a water-bearing zone that was 20 feet or greater in thickness, then the base of the USDW was picked at the bottom of the next shallower zone meeting the 20 foot thickness criteria.

- Zone thickness was determined using several different curves, depending on log vintage and presentation. The curves used included gamma-ray, spontaneous potential, short normal and shallow focused resistivity curves.

- The 4.0 ohm-m cut-off was identified on the logs using the deep induction and lateral resistivity curves, depending on the type of recording device.

MAPPING THE BASE OF THE USDW

The water quality boundary condition that defines the base of the USDW is shown on the log presented in Figure 2. Elevation maps were prepared to illustrate the vertical limits of this boundary in Cleveland, Logan and Oklahoma Counties (Plates I, II and III). Elevations of the base of the USDW were determined by subtracting the measured R_o cut-off depth on the log from the datum elevation from which the log was measured.

The USDW basal elevation maps were considered to be reliable on the basis that mapped changes in the elevation of the base of the USDW were found to be coincident with the major structural components associated with Oklahoma City Field and the Nemaha Fault system.

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APPENDIX A

FIELD DEMONSTRATION

DEMONSTRATION OF AN ALTERNATIVE APPLICATION OF THE METHOD

A method has been introduced for using open-hole geophysical logs to characterize and map the water quality boundary condition that defines the base of an USDW. The method demonstrated that C_t can be determined from resistivity logs and is a good indicator of TDS. Because the general quality of ground water is equated with TDS, the method can also be applied to quantify and delineate the regional distribution of water quality in aquifers. In this section, a field example is used to show that logs can be used to make reliable estimates of water quality.

LOCATION OF DEMONSTRATION UNIT

The demonstration unit is located in North-Central Oklahoma County and covers a four-township area (Figure A1). The term "unit" is used to imply both areal and vertical spatial relations.

CONTROL DATA

Validated water chemical data and logs from eleven municipal and USGS test wells, hereinafter referred to as control wells, were used for this demonstration. Control well locations are shown in Figure A1.

The data sets were separated into two groups, designated "Control Group A" and "Control Group B". Assignment of the data sets to each control group was accomplished using a set of random number tables (Akin and Colton, 1963). Six of the data sets were designated as Control Group A, Control Group B consisted of five data sets.

Control Group A (Table A1) was used to formulate empirical associations between formation resistivities and in-situ TDS concentrations. Control Group B data was used to make comparisons between log-derived (calculated) values of in-situ TDS and laboratory-derived (known) values of in-situ TDS.

LOCAL HYDROGEOLOGY

It has been suggested that the Permian sediments that comprise the Garber and Wellington formations were deposited in a fluvial-deltaic system. Variations in grain size and distribution that could influence the relationship between log responses and water quality are characteristic of fluvial-deltaic environments. In consideration of these effects, two detailed geologic cross sections were

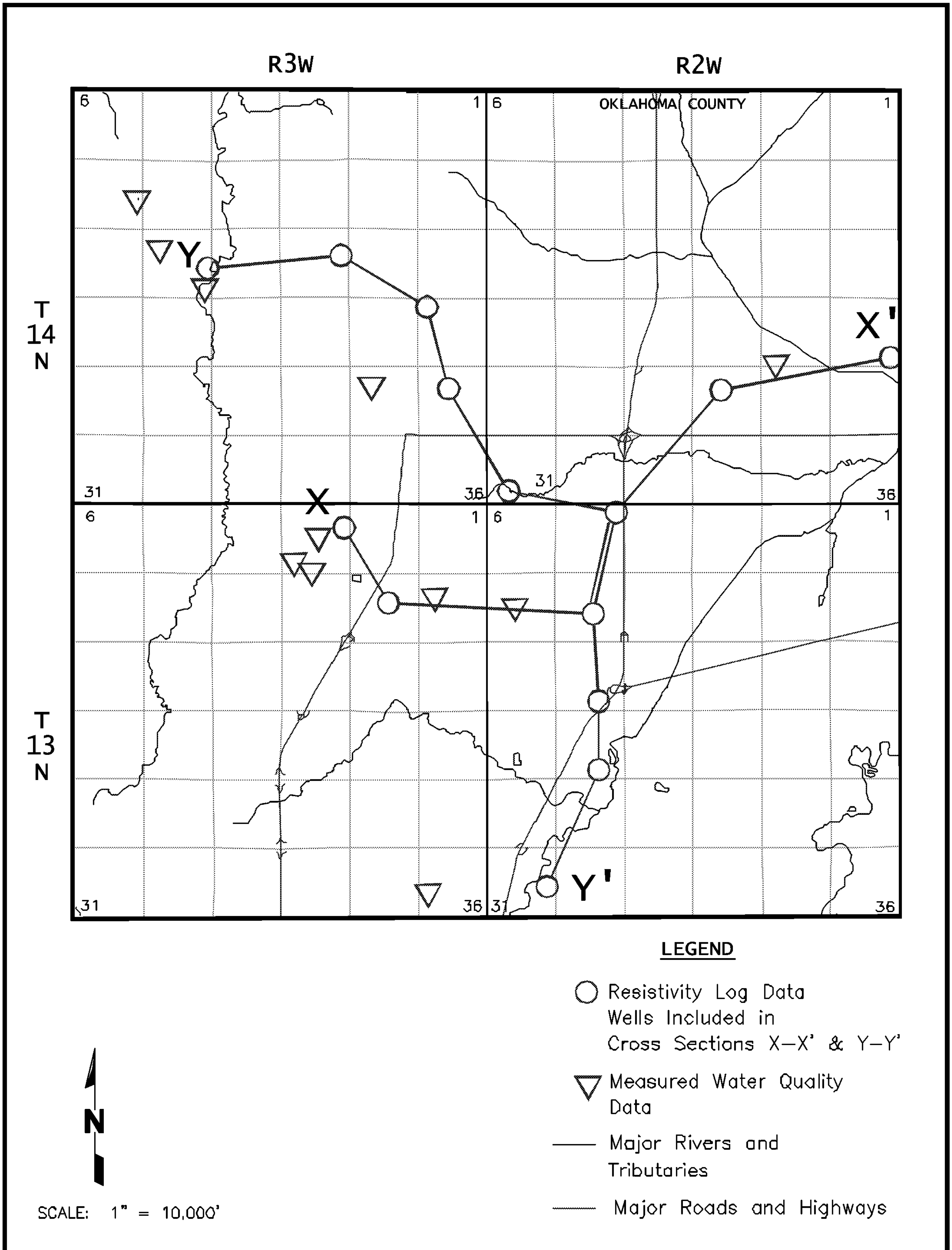

Figure A1: Demonstration unit showing location of control wells and cross sections X-X' and Y-Y'

CONTROL GROUP A DATA USED TO ESTABLISH RELATIONSHIP BETWEEN LABORATORY-DERIVED VALUES OF IN-SITU TDS AND C_t
GARBER & UPPER WELLINGTON FORMATIONS, NORTH-CENTRAL OKLAHOMA COUNTY

Control ID	Well Owner & Name	Spot Location	Sample ID	Sample Depth Interval (feet) from	Sample Depth Interval (feet) to	C_t (µmhos/cm)	In-situ TDS (mg/L)	Water Type	Geologic Unit
A1	City of Edmond: Test Well #3	NE SW SW Sec. 3-T13N-R3W	Ed3-5	227	240	563	447	Ca-Mg-HCO_3	Garber
A2	City of Nichols Hills: Test Well #24	NW SW Sec. 36-T13N-R3W	NH24-6	310	323	748	550	Ca-Mg-HCO_3	Garber
			NH24-5	444	457	350	296	Na-HCO_3	UW-3
A3	City of Edmond: Test Well #55	NE SW NW Sec. 12-T13N-R3W	Ed55-1	248	260	564	454	Ca-Mg-HCO_3	Garber
			Ed55-2	366	380	492	414	Na-HCO_3	UW-3
			Ed55-3	444	458	494	412	Na-HCO_3	UW-3
			Ed55-4	582	596	639	514	Na-HCO_3	UW-2
			Ed55-5	630	644	657	559	Na-HCO_3	UW-2
A4	City of Edmond: Test Well #2	SE SE SE SW Sec. 3-T13N-R3W	Ed2-5	300	313	634	490	Ca-Mg-HCO_3	Garber
			Ed2-4	380	393	618	499	Na-HCO_3	UW-3
			Ed2-3	500	513	767	625	Na-HCO_3	UW-2
			Ed2-2	564	577	757	638	Na-HCO_3	UW-2
A5	USGS: Test Well NOTS 6	NE NE SE Sec. 7-T14N-R3W	N6-222	203	242	575	440	Ca-Mg-HCO_3	Garber
			N6-296	286	306	534	434	Na-HCO_3	UW-3
			N6-327	307	346	551	447	Na-HCO_3	UW-3
A6	City of Edmond: Test Well #56	SE SE NW Sec. 7-T13N-R2W	Ed56-2	263	277	526	419	Ca-Mg-HCO_3	Garber
			Ed56-3	344	358	480	408	Na-HCO_3	UW-3
			Ed56-4	388	402	614	526	Na-HCO_3	UW-3
			Ed56-5	492	506	473	406	Na-HCO_3	UW-2
			Ed56-6	610	624	629	539	Na-HCO_3	UW-2

In-situ TDS: Total Dissolved Solids concentration of water in the formation. TDS value determined from laboratory analyses.
C_t: Specific Conductance of water sample determined from laboratory analyses
UW-2 & UW-3: Refers to stratigraphic intervals associated with the Upper Wellington Formation

Table A1: Field demonstration, Control Group A data constructed (Plates IV and V). The locations of both cross sections are shown in Figure A1.

Since no actual rock samples were analyzed, geologic boundary conditions were interpreted based on electrostratigraphic character, meaning that changes in shale resistivity and specific log curve characteristics were used to establish the limits of the observed stratigraphic units (or packages). Unit boundaries were interpreted as unconformity surfaces, which is consistent with a fluvial-deltaic depositional environment. As indicated on the cross sections and in Figure 2, it was possible to distinguish between the Garber Formation and the underlying Wellington Formation. The Wellington was subdivided into two units called Upper Wellington and Lower Wellington. More detailed stratigraphic work resulted in the recognition of three electrostratigraphic units in the Upper Wellington, which were arbitrarily named (in ascending order) UW-1, UW-2 and UW-3.

ASSOCIATION BETWEEN WATER TYPES AND GEOLOGY

WATEVAL was used to generate Piper diagrams to identify water types. The two following general water types were identified from Control Group A data:

1. $Ca\text{-}Mg\text{-}HCO_3$
2. $Na\text{-}HCO_3$

The zone specificity of the control data made it possible to associate the two general water types with the observed geologic conditions. The results, as shown in Table A1, indicated that $Ca\text{-}Mg\text{-}HCO_3$ water was uniquely associated with the Garber Formation, while $Na\text{-}HCO_3$ water was associated with the Upper Wellington.

EMPIRICAL RELATIONSHIPS BETWEEN IN-SITU TDS AND C_t

Empirical relationships between in-situ TDS and C_t were established for both water types. This was performed using a scatter plot so that the data could be compared graphically. In both cases, a simple straight line fit through the data resulted in the establishment of distinct, well-defined linear relationships (Figure A2).

To compute F values, formation resistivities were determined from calibrated open-hole resistivity logs that had been recorded in oil and gas wells located nearby the control wells. This was achieved by correlating the sampled intervals identified in the control wells to the same interval(s) logged in nearby oil and gas wells. The necessity for this was dictated by the fact that none of the logs that

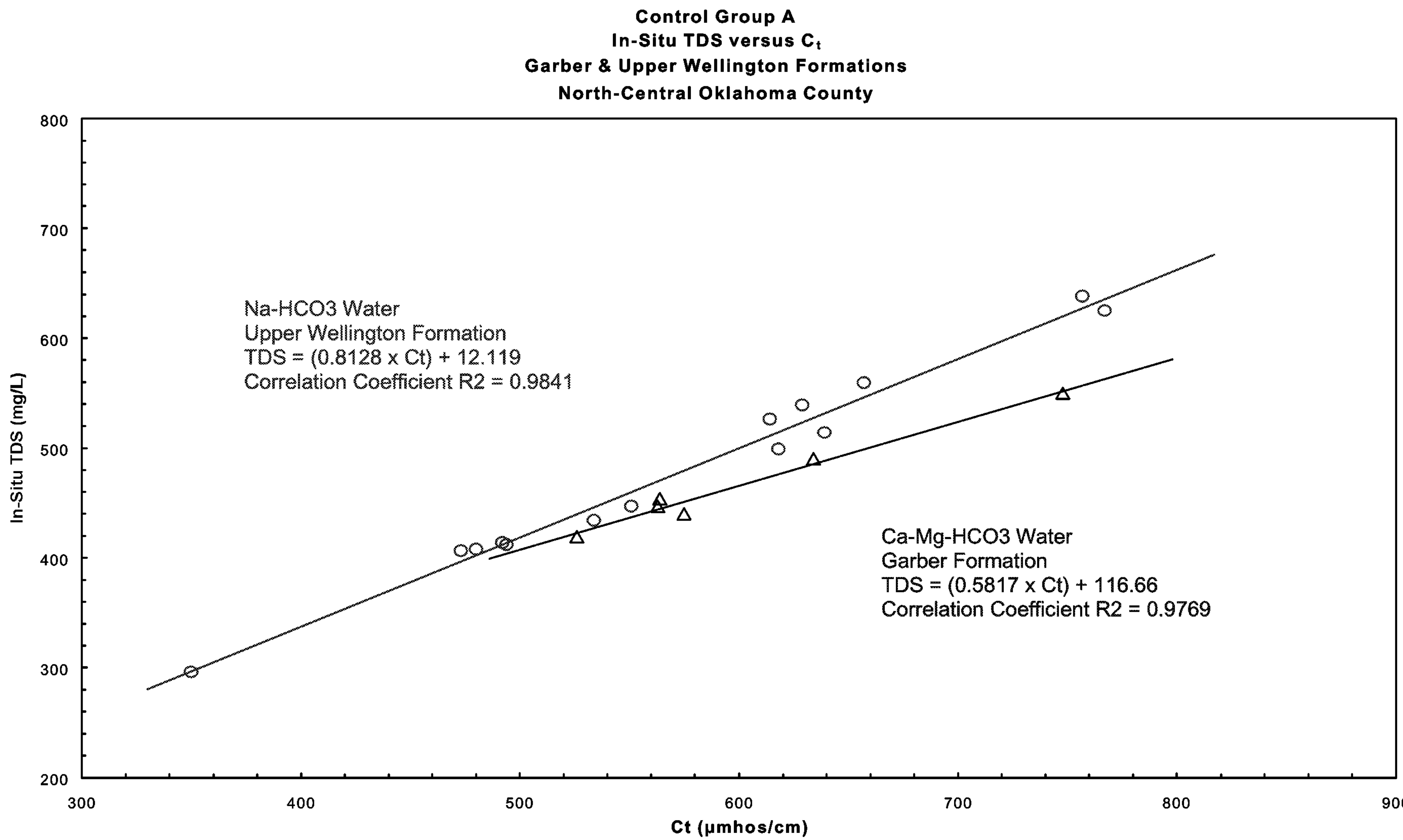

Figure A2: Scatter diagram showing empirical relationship between in-situ TDS_1 and C_t, Control Group A data were recorded in the control wells had been properly calibrated. Consequently, the measured formation resistivities in the control wells were erroneous. However, the general character of the recorded log curves from the control wells was sufficient to permit correlation with offset logs from the oil and gas wells. Unique values of F were computed for the Garber sandstone, UW-2 and UW-3 based on the relationship between in-situ TDS and Ct for the two water types (Table A2). Insufficient data was available to allow F to be computed for UW-1.

VALIDATION OF THE METHOD

Using the in-situ TDS-C_t relationships and computed F values that were established from Control Group A, open-hole resistivity logs were used to compute in-situ TDS concentrations for Control Group B (Table A3). Formation resistivities were determined using the same method applied to Control Group A wells.

Comparisons made between the in-situ TDS concentrations estimated from resistivity logs (i.e. log-derived in-situ TDS_2) and known in-situ concentrations (i.e. lab-derived in-situ TDS_1) showed excellent agreement between the two TDS concentrations. The graphic illustration presented in Figure A3 showed a high degree of correlation (R^2 = 0.9438), which demonstrated that the log-derived in-situ TDS concentrations were accurate.

CONTROL GROUP A DATA USED TO DETERMINE FORMATION FACTOR
GARBER & UPPER WELLINGTON FORMATIONS, NORTH-CENTRAL OKLAHOMA COUNTY

Control ID	Well Owner & Well Name	Spot Location	Sample ID	Sample Interval (feet)		Sample Interval Thickness (feet)	Water Type	FMT (°F)	R_o of Sampled Interval @ FMT (ohm-m)	R_o of Sampled Interval @ 77° F (ohm-m)	R_o*Ft	Mean Value R_o (ohm-m)	C_t of Sampled Interval @ 77° F (µmhos/cm)	C_t*Ft	Mean Value C_t (µmhos/cm)	Mean Value R_w (ohm-m)	F	Geologic Unit	Formation	Age
				from	to															
A1	City of Edmond: Test Well #3	NE SW SW Sec. 3-T13N-R3W	Ed3-5	227	240	13	Ca-Mg-HCO3	62.72	130	108	1402		563	7319				Garber Sandstone (undifferentiated)	Garber	Permian
A2	City of Nichols Hills: Test Well #24	NW SW Sec. 36-T13N-R3W	NH24-6	310	323	13	Ca-Mg-HCO3	63.72	80	67	875		748	9724						
A3	City of Edmond: Test Well #55	NE SW NW Sec. 12-T13N-R3W	Ed55-1	248	260	12	Ca-Mg-HCO3	62.98	85	71	849		564	6768						
A4	City of Edmond: Test Well #2	SE SE SE SW Sec. 3-T13N-R3W	Ed2-5	300	313	13	Ca-Mg-HCO3	63.60	120	101	1310		634	8242						
A5	USGS: Test Well NOTS 6	NE NE SE Sec. 7-T14N-R3W	N6-222	203	242	39	Ca-Mg-HCO3	62.44	95	78	3061		575	22425						
A6	City of Edmond: Test Well #56	SE SE NW Sec. 7-T13N-R2W	Ed56-2	263	267	4	Ca-Mg-HCO3	63.16	95	79	317		526	2104						
						94					**7815**	**83**		**56582**	**602**	**16.61**	**5.00**			
A2	City of Nichols Hills: Test Well #24	NW SW Sec. 36-T13N-R3W	NH24-5	444	457	13	Na-HCO3	65.33	100	86	1119		350	4550				UW-3	Upper Wellington	
A3	City of Edmond: Test Well #55	NE SW NW Sec. 12-T13N-R3W	Ed55-2	366	380	14	Na-HCO3	64.39	90	76	1070		492	6888						
			Ed55-3	444	458	14	Na-HCO3	65.33	90	77	1084		494	6916						
A4	City of Edmond: Test Well #2	SE SE SE SW Sec. 3-T13N-R3W	Ed2-4	380	393	13	Na-HCO3	64.56	80	68	886		618	8034						
A5	USGS: Test Well NOTS 6	NE NE SE Sec. 7-T14N-R3W	N6-296	286	306	20	Na-HCO3	63.43	80	67	1341		534	10680						
			N6-327	307	346	39	Na-HCO3	63.68	80	67	2624		551	21489						
A6	City of Edmond: Test Well #56	SE SE NW Sec. 7-T13N-R2W	Ed56-3	344	358	14	Na-HCO3	64.13	100	85	1185		480	6720						
			Ed56-4	388	402	14	Na-HCO3	64.66	75	64	895		614	8596						
						127					**9309**	**73**		**65277**	**514**	**19.46**	**3.77**			
A3	City of Edmond: Test Well #55	NE SW NW Sec. 12-T13N-R3W	Ed55-4	582	596	14	Na-HCO3	66.98	60	53	740		639	8946				UW-2		
			Ed55-5	630	644	14	Na-HCO3	67.56	55	49	683		657	9198						
A4	City of Edmond: Test Well #2	SE SE SE SW Sec. 3-T13N-R3W	Ed2-3	500	513	13	Na-HCO3	66.00	60	52	678		767	9971						
			Ed2-2	564	577	13	Na-HCO3	66.77	60	53	685		757	9841						
A6	City of Edmond: Test Well #56	SE SE NW Sec. 7-T13N-R2W	Ed56-5	492	506	14	Na-HCO3	65.90	100	87	1215		473	6622						
			Ed56-6	610	624	14	Na-HCO3	67.32	75	66	929		629	8806						
						68					**4000**	**59**		**44578**	**656**	**15.25**	**3.86**			

Table A2: Field demonstration, Control Group A data used to compute formation factor

CONTROL GROUP B, COMPARISON OF LOG-DERIVED IN-SITU TDS_2 WITH LAB-DERIVED IN-SITU TDS_1
GARBER & UPPER WELLINGTON FORMATIONS, NORTH-CENTRAL OKLAHOMA COUNTY

Control ID	Well Owner & Well Name	Spot Location	Sample ID	Sample Depth Interval (feet) from	to	R_o @ FMT (ohm-m)	FMT (°F)	R_o @ 77° F (ohm-m)	F	R_{wa} (ohm-m)	C_a (µmhos/cm)	C_t (µmhos/cm)	Log-Derived In-situ TDS_2 (mg/L)	Lab-Derived In-situ TDS_1 (mg/L)	% Difference in TDS Values	Geologic Unit	Formation	Age
B7	Deer Creek Water Corp.: Neal #2	NE SE SE Sec. 17-T14N-R3W	DCN2-1	208	218	100	62.5	83	5.00	16.54	605	560	468	445	5.0	Garber Sandstone (undifferentiated)	Garber	Permian
			DCN2-2	280	290	100	63.4	84	5.00	16.74	597	541	464	430	7.3			
B8	City of Edmond: Test Well #1	SW SW NE Sec. 3-T13N-R3W	Ed1-6	234	247	140	62.8	116	5.00	23.26	430	534	367	340	7.4			
			Ed1-5	310	323	110	63.7	93	5.00	18.51	540	593	431	448	-3.8			
			Ed1-4	366	379	110	64.4	93	5.00	18.69	535	556	428	445	-3.8			
B9	City of Edmond: Test Well #57	NW SE NW Sec. 26-T14N-R3W	Ed57-2	330	344	120	64.0	101	5.00	20.26	493	510	404	384	5.0			
			Ed57-3	372	386	120	64.5	102	5.00	20.41	490	508	402	375	6.6			
B11	Deer Creek Water Corp.: Test Well #8A	C NW Sec. 17-T14N-R3W	DC8A-1	120	130	70	61.4	57	5.00	11.40	877	928	627	643	-2.5			
			DC8A-2	160	170	105	61.9	86	5.00	17.22	581	745	454	492	-7.7			
			DC8A-4	260	270	100	63.1	83	5.00	16.69	599	645	465	471	-1.3			
B11	Deer Creek Water Corp.: Test Well #8A	C NW Sec. 17-T14N-R3W	DC8A-6	410	420	55	64.9	47	3.77	12.49	801	782	583	625	-6.7	UW-3	Upper Wellington	
B9	City of Edmond: Test Well #57	NW SE NW Sec. 26-T14N-R3W	Ed57-4	476	490	53	65.7	46	3.86	11.88	842	716	606	596	1.1	UW-2		
B10	USGS: Test Well NOTS 3	NE SW SW Sec. 27-T14N-R2W	N3-119	110	129	80	61.3	65	3.86	16.85	594	626	462	461	0.2			
			N3-164	155	174	60	61.9	49	3.86	12.73	785	730	573	574	-0.2			

Ro = formation resistivity
FMT = formation temperature
F = formation factor (dimensionless)
Ca = specific conductance estimated from resistivity log
Ct = specific conductance determined from measured water quality data
Log-Derived In-situ TDS_2 = total dissolved solids concentration of ground water in the formation was estimated from resistivity log.
Lab-Derived In-situ TDS_1 = total dissolved solids concentration was determined from measured water quality data

Table A3: Control Group B, comparison between log-derived in-situ TDS_2 and lab-derived in-situ TDS_1

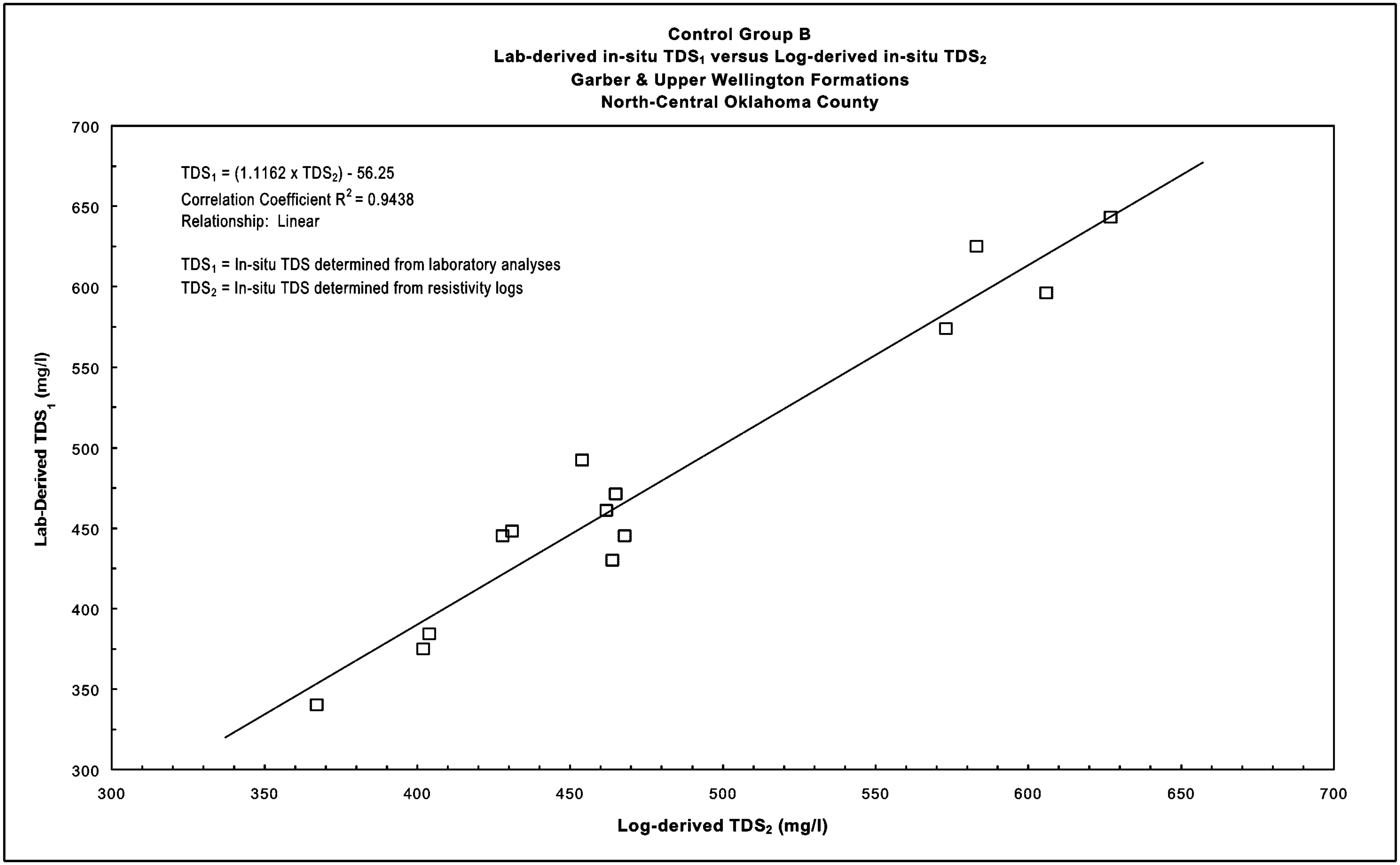

Figure A3: Scatter diagram showing graphical comparison between lab-derived in-situ TDS_1 and log-derived in-situ TDS_2

APPENDIX B

FIELD EXAMPLES

EXAMPLES OF ALTERNATIVE APPLICATIONS OF THE METHOD

Two examples are presented that illustrate the practical application of using open-hole geophysical logs in the performance of ground water work. The first example demonstrates how logs were actually used to aid in assessing the impact on water quality caused by over pumping in the Edwards Aquifer in South Texas. The second example explains how logs could be applied to help address water quality issues that are related to the presence of natural trace elements in ground water supplies.

EDWARDS AQUIFER

In 1985 a research study was initiated by the Edwards Aquifer Authority (EAA, then known as the Edward Underground Water District) in cooperation with the USGS, the Texas Water Development Board (TWDB), and San Antonio Water Systems (SAWS) to respond to concerns that increased withdrawals from wells located near the "*bad water line*" would cause saline water encroachment into fresh water portions of the aquifer.

The "*bad water line*" represents the regional boundary between fresh water and saline water, and (not to be confused with "*treatable water*", which is defined as less than 10,000 mg/L TDS) is defined by an isoconcentration line representing 1,000 mg/L TDS. To evaluate the potential impact of over pumping on water quality, the location of the "bad water line" had to be precisely delineated. Because water quality data from the area proved to be too sparse to allow the trace of the "bad water line" to mapped with any certainty, the EAA, under the advisement of a geological consultant, concluded that open-hole logs could be used to accomplish the objectives of their investigation.

Using TDS as an indicator, open-hole geophysical logs were used to construct regional water quality maps and precisely delineate the trace of the "bad water line" across ten counties for a distance of approximately 164 miles (Schultz, 1992 and 1993). Precise delineation of the "bad water line" allowed the EAA to strategically locate several deep monitoring wells to evaluate and monitor the encroachment of saline water into the fresh water portion of the aquifer. Water samples collected from these wells confirmed that the log-derived TDS concentrations were accurate. Other benefits that have been realized from the use of logs in the EAA study are as follows:

- ✍ Fresh water was discovered to be underlying an area approximately 142 square miles in size that had previously been thought to contain only saline water.
- ✍ Open-hole well logs are being used to provide critical information needed to design and complete new wells, as well as identify future well sites. The cost to drill and complete a water supply well in the San Antonio area is

approximately $250,000.00, exclusive of land acquisition and permitting expenditures.

- The water quality maps that were generated from the log data are being used by the EAA to make regulatory decisions that pertain to permitting, drilling and water resource development issues. The USGS is also using the maps, in conjunction with other geologic data, to investigate and model the impacts of high-concentration sulfate water on fresh water portions of the aquifer.

- Open-hole logs are being used to design and strategically locate aquifer recovery and storage (ARS) wells.

TRACE ELEMENTS

Studies conducted by Norvell (1995) in the Garber-Wellington Aquifer and research conducted in other aquifers suggest that certain dissolved trace elements like arsenic are geochemically associated with specific water types. Work completed by Alger (1966), Jones and Buford (1951) and Turcan (1966) implies that classification of water types can be achieved using open-hole geophysical logs. Consequently, there is evidence to indicate that at a minimum, ranges in the concentration and distribution of trace elements can be indirectly determined from logs and mapped.

Some potential benefits to the application of logs for addressing ground water quality issues related to the presence of trace elements have been identified as follows:

- The presence of dissolved trace elements in ground water is a ubiquitous problem, and any method that would employ the use of geophysical logs for delineating geochemical distributions of these elements could be applied in other geographic areas.

- The potential for siting water supply wells in a bad location would be significantly reduced, thus minimizing potential economic impact on public water suppliers and their customers.

- The information would be useful for designing and completing new water supply wells.

- Well rehabilitation requirements could be properly addressed and budgeted for.

- Knowledge of the distribution and range of dissolved trace element concentrations in a well field would provide information that could be used to estimate water treatment and sludge disposal requirements and costs.

APPENDIX C

MISAPPLICATION OF THE METHOD

MISAPPLICATION OF METHOD BY EXAMPLE

The basic concepts applied to the interpretation of open-hole resistivity logs in oil field applications are not directly relevant to fresh water formations. Two examples are provided, which illustrate why it is essential to understand how formation resistivity measurements are influenced by the chemistry of fresh water.

EXAMPLE 1: EFFECT OF SURFACE CONDUCTANCE

In this example a resistivity-derived value of porosity is computed using a measured C_t value from a test interval in the fresh water portion of the USDW. The point of the exercise is to demonstrate the profound effects of surface conductance on log computations in fresh water formations.

Assumptions:

All resistivity and conductivity values are temperature corrected to 77 °F

Porosity (F) = unknown

C_t = 614 μmhos/cm,

Water type is Na-HCO_3 from test interval in a City of Edmond test well located in Section 7-T13N-R2W, Oklahoma County

R_{w77} = 16.3 ohm-m, from equation *(6)*

R_{o77} = 64 ohm-m, temperature-corrected formation resistivity of test zone

$F = R_{o77}/R_{w77}$, equation *(5)*

$F = 0.81/ F^2$, equation *(7)* (Schlumberger, 1972)

Solution:

$0.81/ F^2 = R_{o77}/R_{w77}$

$F^2 = 0.81 \times (16.3/64)$

$F = [0.81 \times (16.3/64)]^{1/2}$

$F = .05$

Sandstone porosities averaged 30% in fresh water portions of the USDW

EXAMPLE 2: USE OF INACCURATE PARAMETERS

This example demonstrates what can happen when inaccurate or assumed data parameters are used to quantify ground water quality.

In a study performed by Laughlin (1981), inaccurate values for porosity and R_w were used to compute the R_o cut-off that represented the base of the USDW. Porosity was assumed to be 18% and the value used for R_w was 0.56 ohm-m. As a consequence of using these input values, the R_o cut-off was computed to be 15 ohm-m. Based on the empirical relationships developed in this study, a formation resistivity of 15 ohm-m would equate to an in-situ TDS concentration equal to 2,868 mg/L.

APPENDIX D

TABLE SUMMARIES OF WELL LOGS USED TO MAP USDW

TABLE D1: LIST OF WELL LOGS USED TO MAP THE BASE OF THE USDW IN CLEVELAND COUNTY
BASE OF THE USDW DEFINED AS 10,000 mg/L TOTAL DISSOLVED SOLIDS (RESISTIVITY CUT-OFF = 4 OHM-METERS)

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
06N	01E	02	NW	NW	SE			D	B	B			STAATS #1	E.J. KUBAT	DB	1095	350	745	6458	242	ER, SP
06N	01E	06	SW	NE	SE			D	A	C			BRANDENBURG #1	OLSEN DRILLING CO.	KB	1091	790	301	6863	505	ER, SP
06N	01E	12	SW	SE	SE			D	D	C			URBANSKY #1	C.W.VAN EATON	KB	1044	195	849	5749	160	IEL, SP
06N	01E	13	SE	NW	NE			A	B	D			LAMBDIN #1	MERRIL FLEMING	KB	1038	275	763	5855	161	IEL, SP
06N	01E	16	SW	NE				A	C				RAY MC CARTHER #1	CHARLES B. WRIGHTMAN	KB	1113	575	538	7562	508	ER, SP
06N	01E	17	SW	NE	NW			B	A	C			CARPENTER #1	AMERADA PETR. CORP.	DB	1032	475	557	6756	428	ER, SP
06N	01E	22	SE	SE	NW			B	D	D			SIMONS #1	W.B. OSBORN OPERATOR	DF	1042	290	752	6517	208	IEL, SP
06N	01E	26	SE	SE				D	D				DEES #1	SCHAFER DRILLING CO	KB	1066	270	796	6268	222	ER, SP
06N	01E	29	NW	NW	NE			A	B	B			HOLMES #1	NORTHERN OIL ET AL.	KB	1076	490	586	6723	237	ER, SP
06N	01E	30	NE	SE	SW			C	D	A			SMITH #1	SCHAFER DRILLING. CO.	KB	1119	370	749	5854	227	ER, SP
06N	01E	33	SE	NE	SW			C	A	D			FRIZZELL #1	APCO OIL CO.	KB	1041	215	826	586	76	IEL, SP
06N	01E	34	NE	SW				C	A				WALKER-HOFFMAN #1	RAMBLER PROD. CO.	KB	1035	450	585	6508	408	IEL, CDL, CNL, GR
06N	01W	03	NW	SW				C	B				NEWBURN-COX #1	TEEPEE DRILLING CO.	DB	1100	645	455	6814	165	ER, SP
06N	01W	04	E/2	SW	NE			A	C				WARNER NO. 1	KROY AMERICAN OILS, INC	KB	1061	470	591	6837	253	ER, SP
06N	01W	09	SW	NE				A	C				HOBSON #1	RHOADES OIL CO	KB	1083	485	598	7442	140	IEL, SP
06N	01W	10	NE	NE	SW			C	A	A			WASHBURN NO. 1	WEIMER-MILLER	KB	1103	755	348	7525	687	ER, SP
06N	01W	23	S/2	SW	SE			D	C				LITTLE #1	APACHE OIL CORP.	KB	1062	350	712	6125	272	ER, SP
06N	01W	24	E/2	NE	NE			A	A				ANDERSON NO. 1	R.E. HIBBERT	KB	1109	455	654	6933	372	ER, SP
07N	01E	01	NW	NW	NE			A	B	B			STOKES #1	L.J. HORWITZ	KB	1077	480	597	6412	158	ER, SP
07N	01E	03	NW	SW	NW			B	C	B			HEFNER NO. 1	GEORGE E. CAMERON, INC	KB	1110	468	642	6600	219	IEL, SP
07N	01E	06	SE	NW	SW			C	B	D			#1 WALKER "E"	PETROLEUM, INC.	KB	1194	840	354	7118	510	IEL, SP
07N	01E	07	SW	SW	NW			B	C	C			WARD NO. 1	ASHLAND OIL & REFG. CO.	KB	1140	670	470	7085	521	ER, SP
07N	01E	09	SW	SE	NW			B	D	C			BOB SIMMONS NO. 1	P.G. LAKE, INC. & AMAREX	KB	1187	660	527	6079	632	DIL, SP
07N	01E	10	W/2	E	SW	SW		C	C				MEYER #1	MAY PETROLEUM INC.	KB	1135	799	336	7366	708	DIL, SP
07N	01E	11	SW	SW	SW			C	C	C			GREENMORE NO. 1	GOFF-LEEPER DRLG. CO.	KB	1101	435	666	6459	296	ER, SP
07N	01E	12	NW	NW	NE			A	B	B			KELSEY NO. 1 (SMITH)	ENERSOURCE ROYALTY	KB	1179	450	729	5904	373	DIL, GR, SP
07N	01E	15	NW	NW	SW			C	B	B			KROUCH #1	KERR-MCGEE OIL	KB	1123	650	473	6002	508	ER, SP
07N	01E	19	SE	NE	NW			B	A	D			NANCE "B" NO. 2	WOODS PETROLEUM CO.	KB	1181	765	416	7044	646	ER, SP
07N	01E	21	NE	NE	NW			B	A	A			BRENDLE NO. 1	KINGWOOD OIL CO	KB	1192	685	507	6137	549	IEL, SP
07N	01E	26	SW	SW	NE			A	C	C			SMITH #1	HELMERICH & PAYNE	KB	1108	430	678	6584	385	ER, SP
07N	01W	01	SW	NW				B	C				MAGERS #1	BIG CHIEF DRILLING CO.	DB	1197	720	477	7352	607	ER, SP
07N	01W	02	SE	NE	NE			A	A	D			CROXTON #1	OIL CAPITOL CORP	KB	1222	915	307	7574	100	ER, SP
07N	01W	03	NW	SW	NW			B	C	B			RHODES NO. 1	FAIN-PORTER DRLG. CORP	KB	1141	905	236	7696	707	ER, SP
07N	01W	04	SE	NE				A	D				MC BRIDE #1	REES & BUCK CO	KB	1168	1010	158	7663	655	IEL, SP
07N	01W	09	SE	NE	NE			A	A	D			EASTEP NO. 2	TRICE PROD. CO.	KB	1132	780	352	7325	674	ER, SP
07N	01W	10	NE	SE	NE			A	D	A			NEMECEK#1	WESTLAND OIL	KB	1178	795	383	8122	772	IEL, SP
07N	01W	12	SE	SE	NE			A	D	D			SHAW #1	AN-SON PETROLEUM	KB	1160	735	425	7153	556	ER, SP
07N	01W	23	NE	SE				D	A				OWENS #1	ASHLAND OIL & REF. CO.	KB	1158	495	663	7245	362	ER, SP
07N	01W	24	NE	NE	NE			A	A	A			GARNER NO. 1	EMPIRE PRODUCING CO.	KB	1162	NS	NS	7112	628	ER, SP
07N	01W	32	S/2	SE	NE			A	D				OLSON #1	TURNEY OIL CO.	KB	1076	352	724	7583	247	ER, SP
08N	01E	10	NE	NE	SW			C	A	A			SMITH #1	RYAN-MACMILLAN	KB	1048	645	403	6230	424	ER, SP
08N	01E	11	SW	SW	NE			A	C	C			BRENDLE #1	RYAN & MORTON	KB	1086	590	496	6449	424	ER, SP
08N	01E	12	NW	NW	NW			B	B	B			WILCOX #1	FALCON SEABOARD	DB	1025	510	515	6316	203	ER, SP
08N	01E	13	NW	SW	SW			C	C	B			ROLLF #1	SINCLAIR OIL & GAS CO.	GL	1040	485	555	6293	397	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
08N	01E	14	SE	SW	SE			D	C	D			CAPEHART NO. 3	JOHNSON & GILL	KB	1012	470	542	6225	380	ER, SP
08N	01E	15	NW	NW	SW			C	B	B			EVANS #1	HERMAN BROWN	KB	1073	640	433	6490	508	ER, SP
08N	01E	23	NW	NE	NE			A	A	B			ROSELIUS NO. 1	RANDEL R. MORTON	KB	1044	525	519	6293	426	ER, SP
08N	01E	28	SE	SE	SW			C	D	D			MC KIDDY #1	FOREST OIL CO.	KB	1058	430	628	5929	373	IEL, SP
08N	01E	29	NE	NE	SW			C	A	A			RUTH FOX #1	RANDALL R. MORTON	KB	1182	650	532	7014	408	ER, SP
08N	01E	32	SW	NW				B	C				RITCHERSON #1	ASHLAND OIL	KB	1121	740	381	7051	368	ER, SP
08N	01E	35	NE	NW	NE			A	B	A			OWENBEY NO. 1	HERMAN BROWN ET AL	KB	1129	495	634	6463	448	ER, SP
08N	01W	01	S/2	SW	SE			D	C				COX #1	ANDERSON-PRICHARD OIL	DF	1130	710	420	6935	669	IEL, SP
08N	01W	02	NW	NE	NW			B	A	B			STANFORD NO. 1	CHAMPLIN OIL	KB	1150	655	495	7223	602	ER, SP
08N	01W	04	NW	NW	NE			A	B	B			SULLIVANT NO. 1	HERMAN & GEORGE BROWN	KB	1118	710	408	7576	617	ER, SP
08N	01W	07	SE	SE	SW			C	D	D			BROWN#1	R.E. HIBBERT	KB	1130	470	660	7940	368	ER, SP
08N	01W	08	NW	NW				B	B				RALPH CADDELL NO. 1	FRANK G. WEIMER	KB	1136	625	511	7904	443	ER, SP
08N	01W	10	NE	SW	SW			C	C	A			H. BERMAN #2	CONTINENTAL OIL CO.	KB	1179	510	669	6645	387	IES, SP
08N	01W	11	NE	SE				D	A				DEAVER NO. 1	DAVON DRILLING CO.	KB	1108	520	588	7085	402	ER, SP
08N	01W	14	NE	NE	SW			C	A	A			WITT #1	PETROLEUM, INC.	KB	1140	525	615	7182	407	ER, SP
08N	01W	15	NE	SW	NE			A	C	A			F. COOK JR. #2	CONTINENTAL OIL CO.	KB	1192	600	592	7228	352	ER, SP
08N	01W	18	NW	NW				B	B				BLACK #1	R.E. HIBBERT	KB	1141	575	566	7695	502	ER, SP
08N	01W	24	NW	NE	SW			C	A	B			ELLIS NO. 1	DAVON DRILLING CO.	KB	1180	610	570	7207	552	ER, SP
08N	01W	27	SW	NW	NE			A	B	C			DEMAND #1	CHESTER H. WESTFALL	KB	1246	690	556	7518	582	ER, SP
08N	01W	33	NW	NW	SE			D	B	B			SCHOCK NO. 1	AN-SON PETROLEUM CORP.	KB	1189	660	529	7944	504	ER, SP
08N	01W	36	SW	NW				B	C				PATTERSON #1	LION OIL COMPANY	KB	1232	755	477	7077	642	IEL, SP
08N	02W	06	SE	NE	SE			D	A	D			NAVY #5	UNION TEXAS NATURAL GAS CORP.	KB	1170	740	430	1125	30	IEL, SP
08N	02W	14	NW	NW				B	B				VALOUCH NO. 1	GOFF-LEEPER	KB	1184	755	429	8701	681	ER, SP
08N	02W	16	SE	NW				B	D				TULLIUS NO. 4	ANDERSON PRICHARD OIL	KB	1174	560	614	1070	150	IEL, SP
08N	02W	23	SE	NE	NW			B	A	D			NOBLE, TAYLOR #1	HARPER & TURNER OIL CO.	DF	1167	770	397	835	25	ER, SP
09N	01E	07	NE	NE				A	A				WILLIAMS NO. 1	MANLEY & WILLIAMS	KB	1059	745	314	6601	153	ER, SP
09N	01E	09	SE	SE	SE			D	D	D			GO-DO-PEA-SE #1	J.E. MANNING	KB	1107	570	537	6413	445	IEL, SP
09N	01E	10	NW	NW				B	B				#1 ROOKSTOOL	R.H. DEARING INC.	DB	1152	720	432	6455	317	ER, SP
09N	01E	12	NE	NW				B	A				WILSON #1	CHARLES H. MEE	DB	1052	720	332	6209	146	ER, SP
09N	01E	15	S/2	SW	SW			C	C				CITIZENS NAT'L BANK #1	CRESLENN OIL CO	KB	1110	570	540	5827	523	IEL, SP
09N	01E	16	NE	NE	SE			D	A	A			CITIZENS NAT'L BANK #A-1	JOHN A. TAYLOR	KB	1138	650	488	5844	524	IEL, SP
09N	01E	17	NW	NE				A	B				GODOPEASE #1	OIL & GAS ROYALTY CORP	KB	1141	770	371	6812	410	ER, SP
09N	01E	18	NE	SW				C	A				BENARD NO. 1	WILCOX-HENRY	KB	1026	780	246	6578	447	IEL, SP
09N	01E	21	SE	SE	SW			C	D	D			WARMACK #1	SAMEDAN OIL CO	DB	1072	725	347	6154	420	ER, SP
09N	01E	22	E/2	NE	NW			B	A				WHITE #2	WILLIAM M. FULLER	KB	1037	650	387	5735	504	IEL, SP
09N	01E	24	SW	NE	SE			D	A	C			MACK #1	SMITH BROS. DRLG. CO	DB	1050	560	490	6222	280	ER, SP
09N	01E	25	NE	SW	SW			C	C	A			LITTLE FISH UNIT #1	THE OHIO OIL CO.	KB	1041	610	431	6186	346	ER, SP
09N	01E	25	NE	NW				B	A				ESSARY NO. 1	JONES, SHELBURNE ET AL	KB	1107	665	442	6454	474	ER, SP
09N	01E	26	SE	NE	SE			D	A	D			JOE BRENDLE #1	AMERADA PETR. CORP.	KB	1086	550	536	5915	287	ER, SP
09N	01E	28	NE	NE				A	A				EDNA HALL #1	OLYMPIC PETROLEUM CO.	KB	1024	460	564	5809	400	IEL, SP
09N	01E	32	SE	NE	SE			D	A	D			GOODIN #1	ERLE P. HALLIBURTON CO.	DB	1041	560	481	5798	423	ER, SP
09N	01E	33	SE	NW	SW			C	B				KING #1	HALLIBURTON OIL	DB	1063	668	395	5813	436	ER, SP
09N	01E	34	NE	SE	NW			B	D	A			AUSTIN ESTATE #1	OLYMPIC PETROLEUM CO.	KB	992	335	657	6381	301	ER, SP
09N	01E	36	NE	SE	SE			D	D	A			BANNING #1	ZEPHYR DRLG. CO.	DB	981	430	551	6244	172	ER, SP
09N	01W	03	SE	SE	NW			B	D	D			LE MASTER NO. 1	CHARLES B. WRIGHTSMAN	KB	1178	902	276	6239	573	ER, SP
09N	01W	06	NW	SW	NE			A	C	B			KING #1	J.A. CHAPMAN	DF	1114	885	229	6312	613	ER, SP
09N	01W	07	NW	NE	NE			A	A	B			MADDOX NO. 1	J. CHAPMAN & G. PARKER	KB	1067	825	242	6277	600	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
09N	01W	11	NW	NW	SE			D	B	B			KELLEY NO. 1	HERMAN & GEORGE BROWN	KB	1170	815	355	6882	533	ER, SP
09N	01W	13	SE	SE	NE			A	D	D			MCCOY NO. 1	J.D. WRATHERS, JR.	KB	1123	795	328	7475	519	ER, SP
09N	01W	16	NW	NW	SW			C	B	B			NORA TODD NO. 1	MARION OIL CO.	KB	1060	790	270	7172	662	ER, SP
09N	01W	17	SE	NE	SE			D	A	D			FORREST MOUSER #6	THE OHIO OIL CO.	KB	1118	795	323	7201	660	ER, SP
09N	01W	18	SE	NW				B	D				MATLOCK #1	J.P. OWEN	KB	1111	875	236	7375	652	IEL, SP
09N	01W	19	NW	NE	SW			C	A	B			SMITH #1	TRICE PROD. CO.	KB	1173	738	435	8160	695	IEL, SP
09N	01W	20	NW	NE	SE			D	A	B			R.E. CONNELLY #1	HERMAN BROWN	KB	1072	796	276	7160	566	ER, SP
09N	01W	21	NW	NE	SW			C	A	B			BRIGGS NO. 1	HERMAN BROWN	KB	1044	775	269	7164	562	ER, SP
09N	01W	22	NW	NW	NE			A	B	B			ROHART NO. 1	DAVON DRILLING CO	KB	1101	836	265	7137	610	ER, SP
09N	01W	23	SW	SE	NE			A	D	C			BREHM NO. 1	HERMAN BROWN	KB	1118	770	348	7550	538	IEL, SP
09N	01W	24	SW	NW				B	C				WILSON #1	TEXAS COMPRESSION	KB	1155	728	427	7581	466	IEL, SP
09N	01W	25	NE	NW	NW			B	B	A			WALKER #1	HERMAN BROWN	KB	1096	660	436	7540	563	IEL, SP
09N	01W	27	NW	SW	NE			A	C	B			OTTO HEIMS NO. 1	THE OHIO OIL CO.	KB	1087	690	397	6998	620	ER, SP
09N	01W	29	NE	SE				D	A				SCHONWALD NO. 1	AN-SON PETROLEUM	KB	1144	680	464	7450	595	ER, SP
09N	01W	30	SW	SE	SW			C	D	C			RUSSELL NO. 1	TEXAS EASTERN	KB	1193	827	366	8367	734	IEL, SP
09N	01W	31	SW	NW				B	C				LULA VAUGHN #1	THE CARTER OIL CO.	DB	1154	700	454	7148	570	ER, SP
09N	02W	01	NW	NE	SE			D	A	B			FRANKLIN, NELSON NO. 1	J.CHAPMAN & G.PARKER	DF	1104	900	204	6317	680	IEL, SP
09N	02W	03	NE	SE				D	A				KUHLMAN NO. 1	LYLE JOHNSON	KB	1089	868	221	7352	689	ER, SP
09N	02W	03	SE	NW				B	D				WILLIAMS #B-1	E. LYLE JOHNSON	KB	1145	880	265	7360	720	IEL, SP
09N	02W	04	NW	SE	SW			C	D	B			JENNINGS NO. 1	R.E. HIBBERT	KB	1136	862	274	6681	692	ER, SP
09N	02W	10	NE	SE	NE			A	D	A			OLIPHANT NO. 1	GOFF-LEEPER & WILDCO OIL	DF	1140	814	326	8110	675	IEL, SP
09N	02W	13	NE	NW				B	A				STRONG NO. 1	DAVON DRILLING CO.	KB	1145	823	322	8240	572	ER, SP
09N	02W	14	NW	NW	SW			C	B	B			HANSMEYER #1	R.E. HIBBERT	KB	1179	842	337	8677	721	IEL, SP
09N	02W	14	NW	NW	SW			C	B	B			HANSMEYER #1	R.E. HIBBERT	KB	1179	842	337	8677	721	IEL, SP
09N	02W	24	SE	SW	NE			A	C	D			KLEMENT NO. 1	FALCON SEABOARD	KB	1161	788	373	7514	614	ER, SP
09N	02W	27	SW	NE				A	C				BOESKEN NO. 1	DAVON DRILLING CO.	KB	1181	808	373	7645	591	ER, SP
09N	03W	09	NW	NW	NW			B	B	B			GROSS #1	WILSUR KEITH	DB	1142	1010	132	9312	612	ER, SP
10N	01E	04	SW	SE	NW			B	D	C			ADA FLEMMING #A-1	THE OIL CAPITOL CORP	KB	1195	735	460	6475	411	IEL, SP
10N	01E	06	NW	NW	NW			B	B	B			HIRSCHE #1	PIGGOT & LAW	DB	1156	730	426	6635	318	ER, SP
10N	01E	09	SE	NE	NE			A	A	D			WODKINS NO. 1	P.H. WELDER	KB	1225	890	335	6481	386	ER, SP
10N	01E	10	NW	SE				D	B				COLEY #1	FALCON SEABOARD	RT	1191	810	381	6410	290	ER, SP
10N	01E	13	NW	SW	NW			B	C	B			R.E. WILSON #1	GULF OIL CORP	KB	1160	660	500	6131	420	ER, SP
10N	01E	14	NW	NE	NE			A	A	B			FOSTER "B" #1	APACHE OIL CORP.	KB	1162	670	492	6117	445	ER, SP
10N	01E	15	NW	NW				B	B				FRANKLIN #1	WOODS PETROLEUM CO.	KB	1238	910	328	6439	237	DIL, SP
10N	01E	16	SE	NW				B	D				STATE LAND NO. 1	H. KRAMER & E.L. COX	KB	1209	945	264	6416	415	ER, SP
10N	01E	22	SE	NE	SW			C	A	D			BARTON NO. 1	REPUBLIC NATURAL GAS	KB	1177	615	562	6600	486	ER, SP
10N	01E	27	NE	NW	NE			A	B	A			WILSON ESTATE #1	GULF OIL CORP	KB	1145	915	230	6285	331	ER, SP
10N	01E	28	NW	NW	SE			D	B	B			WILSON #1	HERMAN BROWN	KB	1142	600	542	6376	257	ER, SP
10N	01E	29	NW	SW	NW			B	C	B			NO. 1 GUNTER	NATIONAL ASSOC. PETR.	KB	1149	815	334	6466	605	ER, SP
10N	01E	33	SW	NE				A	C				PARR NO. 1	THE SUPERIOR OIL CO.	KB	1185	940	245	7176	595	DIL, SP
10N	01W	02	SW	SE	SE			D	D	C			PRINGLE #1	DEEP ROCK OIL CORP.	DB	1143	855	288	5911	396	ER, SP
10N	01W	13	SE	SW	SW			C	C	D			HAYES #1	DAVIDOR & DAVIDOR	KB	1150	940	210	7498	472	ER, SP
10N	01W	22	SE	SE	SW			C	D	D			LITTLE NO. 1	PARRISH & REYNOLDS	KB	1185	800	385	7852	512	ER, SP
10N	01W	23	NE	NE	SE			D	A	A			OWENBEY NO. 1	AN-SON PETROLEUM	KB	1188	840	348	7443	498	ER, SP
10N	01W	26	NE	NW	SW			C	B	A			LUCAS #1	PETROLEUM, INC.	KB	1170	815	355	7577	531	IEL, SP
10N	01W	30	SE	SE	SE			D	D	D			HALL NO. 1	HERMAN BROWN	KB	1158	800	358	7828	580	ER, SP
10N	01W	31	SW	SE	SW			C	D	C			ZIMMERMAN #1	J.CHAPMAN & G. PARKER	KB	1077	800	277	7316	557	IEL, SP

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			Legal Description					USGS Description													
10N	01W	32	SW	NW	NE			A	B	C			SUBLETT NO. 1	HERMAN BROWN	KB	1143	977	166	7282	563	ER, SP
10N	01W	35	SE	NE	NE			A	A	D			QUIETT NO. 1	RYAN CONSOLIDATED	KB	1133	760	373	7073	487	IEL, SP
10N	02W	02	SW	NW	SE			D	B	C			CONLEY #1	EDDIE FISHER	DB	1184	1020	164	6814	344	ER, SP
10N	02W	03	SW	NE	NW			B	A	C			RICE NO. 2	R.E. HIBBERT	KB	1258	1227	31	6765	620	ER, SP
10N	02W	10	SW	NE	NE			A	A	C			SHROYER NO. 1	CHRISTIE-MITCHELL ET AL	KB	1195	1210	-15	7249	613	ER, SP
10N	02W	16	NE	SW	SW	SE		D	C	C	A		STATE #5	ANDERSON-PRICHARD OIL	KB	1164	1160	4	7429	821	IEL, SP
10N	02W	17	SE	NW				B	D				LINDSAY #3	TRICE PROD. CO.	KB	1234	1205	29	7685	740	ER, SP
10N	02W	26	SE	SE				D	D				COOK #1	UNITED CARBON CO. INC	KB	1157	1328	-171	8232	600	ER, SP
10N	02W	29	SE	SE	SW			C	D	D			YOUNG #4	HERMAN & GEORGE BROWN	KB	1160	1011	149	7631	765	ER, SP
10N	02W	33	SW	SE				D	C				KELLER #1	BILLY BRIDEWELL	KB	1155	948	207	6599	743	ER, SP
10N	02W	34	NW	NW	SE			D	B	B			FOX #1	ASHLAND OIL & REF. CO.	KB	1116	890	226	8147	650	ER, SP
10N	02W	35	SW	SW				C	C				SHELBURG #1	PETROLEUM, INC.	KB	1112	943	169	7583	638	ER, SP
10N	02W	36	NE	NW	NE			A	B	A			MOORE, STATE #36-1	ARROWHEAD ENERGY INC.	KB	1095	990	105	1224	66	DIL, SP
10N	02W	36	NW	NE	SW			C	A	A			SCHOOL LAND #1-B	D.F. O'ROURKE	KB	1162	1120	42	6605	625	ER, SP
10N	03W	12	SW	SW				C	C				NAIL NO. 1	LONE STAR PROD. CO	KB	1259	1055	204	998	96	ER, SP
10N	03W	13	NW	SE				D	B				STEINMEYER #1	HOME-STAKE PROD. CO.	KB	1224	1010	214	7746	200	ER, SP
10N	03W	21	SW	NE				A	C				MILLER NO. 1	STANOLIND OIL & GAS CO	KB	1226	1112	114	1021	29	IEL, SP
10N	03W	25	W/2	NW	NE			A	B	W/2			PERRY JURY NO. 1	FAIN-PORTER & TRICE	KB	1190	1045	145	8343	837	ER, SP
10N	03W	27	NW	NW				B	B				SULLIVAN NO. 2	SUNRAY MID-CONT. OIL	KB	1217	1070	147	8197	900	ER, SP
10N	03W	29	NE	SE	SW			C	D	A			E.W. HARRIS #1	MID-CONTINENT PETR.	DB	1206	952	254	8290	824	ER, SP
10N	04W	23	SW	NW				B	C				RUSSELL BUTLER NO. 3	CONTINENTAL OIL	KB	1220	952	268	8170	862	ER, SP

REFERENCE DATUM = DATUM FROM WHICH THE LOG FOOTAGE WAS MEASURED

REFERENCE DATUM = DATUM FROM WHICH THE LOG FOOTAGE WAS MEASURED
* REFERENCE DATUM ELEVATION ESTIMATED FROM USGS TOPOGRAPHIC MAP

Abbreviations

DIL = DUAL INDUCTION LOG
IEL = INDUCTION ELECTRICAL LOG
ER = ELECTRICAL RESISTIVITY LOG
GR = GAMMA RAY LOG
SP = SPONTANEOUS POTENTIAL LOG
CDL = COMPENSATED DENSITY LOG
CNL = COMPENSATED NEUTRON LOG

GL = GROUND LEVEL
DF = DERRICK FLOOR
BH = BRADEN HEAD
RT = ROTARY TABEL
DB = DRIVE BUSHING

TABLE D2: LIST OF WELL LOGS USED TO MAP THE BASE OF THE USDW IN LOGAN COUNTY
BASE OF USDW DEFINED AS 10,000 mg/L TOTAL DISSOLVED SOLIDS (RESISTIVITY CUT-OFF = 4 OHM-METERS)

Township	Range	Section	Spot Location of Well: Legal Description	Spot Location of Well: USGS Description	Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
15N	01E	01	SW SE SW	C D C	SHILOH #1	SERVICE DRILLING CO	KB	928	664	264	5346	168	IEL, SP
15N	01E	01	SW SE SW	C D C	SHILOH #1	SERVICE DRILLING CO	KB	928	664	264	5347	168	CDL, GR
15N	01E	02	NE NE NE	A A A	HUMPHREY #1	GEORGE W. DECK	KB	964	690	274	5294	141	ER, SP
15N	01E	03	SE NE SE	D A D	BRISCOE #1	JORDAN PETR. CO	DB	992	845	147	5411	218	ER, SP
15N	01E	04	NE NE SE	D A A	STARKS #1	BAJA PETROLEUM CO	KB	982	670	312	5176	364	IEL, SP
15N	01E	05	SW SW NE	A C C	C.A. MC EWEN NO. 1	AMBASSADOR OIL CORP.	KB	1069	840	229	5219	280	IEL, SP
15N	01E	06	SW SE NE	A D C	TAYLOR #1	JORDAN PETR. CO	DB	1074	570	504	5148	156	ER, SP
15N	01E	07	NW NW NE	A B B	DEAN #1	JORDAN PETR. CO	RT	1113	690	423	5112	158	ER, SP
15N	01E	08	SE SE SE	D D D	FAVER #1	JORDAN PETR. CO	DB	1034	460	574	5019	150	ER, SP
15N	01E	09	SW SW NW	B C C	STARKS #1	THE WIL-MC OIL CORP	KB	1082	400	682	5129	306	IEL, SP
15N	01E	11	NE NE SW	C A A	FAVER NO. 1	AN-SON PETROLEUM CORP.	KB	1006	715	291	5441	200	ER, SP
15N	01E	12	SW SW SE	D C C	COLEMAN #1	FLEET & CONTINENTAL	DB	981	750	231	5455	164	ER, SP
15N	01E	13	NE NW SE	D B A	CHRIST #1	DEEP ROCK OIL CORP	KB	959	715	244	5461	173	ER, SP
15N	01E	14	SW SW NE	A C C	TATE #1	MOORE, MOORE, & MILLER	KB	992	635	357	5188	126	ER, SP
15N	01E	15	NW NW NW	B B B	HATTIE JORDAN #1	MERCURY OIL & REF. CO.	DB	1043	965	78	4972	275	ER, SP
15N	01E	16	SW SE NE NE	A A D C	STATE "C" NO. 4	CHAMPLIN EXPLORATION	KB	1027	718	309	5023	445	DIL, SP
15N	01E	17	NE NE NE	A A A	RALPH #1	PHILLIPS PETR. CO.	DB	1022	465	557	5012	300	ER, SP
15N	01E	19	NE SW NW	B C A	MORGAN #1	FAIN-PORTER DRILLING CO	KB	1139	705	434	5922	224	ER, SP
15N	01E	20	NW NW SE	D B B	#1 STEWART	MIZEL BROTHERS	DB	1011	670	341	5773	142	ER, SP
15N	01E	22	NW SW SW	C C B	JOHNSON NO. 1	O.K. OIL OPERATORS	DF	965	675	290	5007	235	DIL, SP
15N	01E	23	SE NW NW	B B D	H.S. SMITH NO. 2	S.C. CANARY & ASSOC	KB	1059	760	299	4919	174	ER, SP
15N	01E	24	NW SE SW	C D B	MCCLURE #1	MOORE, MOORE, & MILLER	KB	976	620	356	5161	125	IEL, SP
15N	01E	25	NW NE	A B	ADAMS #1	MOORE, MOORE, & MILLER	KB	938	570	368	5440	219	IEL, SP
15N	01E	26	S/2 NW SE	D B	#1 DOUGLAS "A"	MOORE, MOORE, & MILLER	KB	1008	650	358	5077	263	IEL, SP
15N	01E	26	NE SE NW	B D A	BRATCHER #1	MOORE, MOORE, & MILLER	KB	1046	668	378	5568	136	IEL, SP
15N	01E	27	SE NE NW	B A D	KIME NO. 1	LYNN PETROLEUM CO	KB	1005	280	725	5442	143	IEL, SP
15N	01E	28	SW SW	C C	J.O. LE GRANDE	J.A. CHAPMAN	KB	957	450	507	4190	125	IEL, SP
15N	01E	29	SE NE NW	B A D	LOREN BRISCOE NO. 1	POWEL BRISCOE, INC	KB	966	350	616	4306	196	ER, SP
15N	01E	30	NE NW NW	B B A	ADAMS #1	WALTER DUNCAN	KB	1092	525	567	5819	168	ER, SP
15N	01E	31	SE SW NW	B C D	ATTEBERRY NO. 1	POWEL BRISCOE, INC	KB	1047	630	417	4452	197	ER, SP
15N	01E	32	SE SW NE	A C D	DEVINE NO. 1	C.H. NICHOLSON CO	GL	941	470	471	4274	145	ER, SP
15N	01E	33	NW SE	D B	HENRY SMITH #1	J.A. CHAPMAN	KB	937	252	685	4186	160	ER, SP
15N	01E	34	NE SW	C A	GRAHAM #1	J.A. CHAPMAN	KB	918	440	478	4120	134	ER, SP
15N	01E	35	W/2 SE NE	A D	GRAHAM #1	MOORE, MOORE, & MILLER	KB	998	660	338	5535	130	IEL, SP
15N	01E	36	SE NW	B D	STATE #2	MOORE, MOORE, & MILLER	KB	988	602	386	5487	124	IEL, SP
15N	01W	03	SE NE NW	B A D	A. BEIGHTOL 32	THE TEXAS COMPANY	KB	1147	555	592	5303	262	ER, SP
15N	01W	04	SE SE NW	B D D	MC NEIL #1	FLEET DRLG CO	KB	1167	540	627	5959	140	ER, SP
15N	01W	07	SE NE SW	C A D	CUTLER NO. 1	A.R. DILLARD, JR.	KB	1150	482	668	6081	213	ER, SP
15N	01W	08	NW SE	D B	KIGHTLINGER NO. 1	HELMERICH & PAYNE, INC	KB	1235	566	669	6095	319	IEL, SP
15N	01W	09	SW	C	KAREN NO. 1	M & A PETROLEUM	KB	1224	615	609	5894	418	DIL, GR, SP
15N	01W	10	SW SW SW	C C C	NICHOLSON #1	KIRKPATRICK-BALE INC.	DB	1157	570	587	5887	132	ER, SP
15N	01W	11	SE SE SE	D D D	FRAZER #1	ROBERT M. JORDAN	KB	1212	580	632	5417	200	ER, SP
15N	01W	12	NE NW SE	D B A	HUNTER #1	C.H. NICHOLSON CO	KB	1122	660	462	5834	132	ER, SP
15N	01W	13	SE NE NW	B A D	NO. 1 KIGHTLINGER	WARREN DRILLING CO	KB	1129	535	594	5503	253	IEL, SP

Township	Range	Section	Spot Location of Well								Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description				USGS Description												
15N	01W	14	SE	NE			A	D			MAEDELLA NO. 1	JOHN WARREN	KB	1156	570	586	5582	254	IEL, SP
15N	01W	16	SE	NE	SE		D	A	D		SCHOOL LAND #1	O'ROURKE & BAKER	KB	1124	485	639	5988	132	ER, SP
15N	01W	17	SE	SE	NW		B	D	D		HAMLIN #1	HARPER-TURNER	KB	1205	564	641	6109	206	ER, SP
15N	01W	18	SE	NW			B	D			TREAGLE NO. 2	DOWNEY OIL CO.	KB	1200	540	660	6120	505	DIL,SP
15N	01W	19	NW	NE			A	B			CALVERT #1	PELICAN PRODUCTION CO	KB	1226	646	580	6008	478	DIL, SP
15N	01W	23	SW	NE			A	C			BRYANT #1	HALL-JONES OIL CORP	DF	1075	475	600	5925	273	IEL, SP
15N	01W	24	SE	SE	SE		D	D	D		BOECKMAN #1	CHALLENGER MINERALS	KB	1081	520	561	5868	419	DIL, SP
15N	01W	25	NE	NE	NE		A	A	A		GATCHELL #1	W.C. MC BRIDE INC	KB	1059	535	524	5780	182	ER, SP
15N	01W	27	SE	SE	SW		C	D	D		WALKER NO. 1	GAGE OIL CO.	KB	1117	440	677	5358	164	ER, SP
15N	01W	30	NW	NE	SW		C	A	B		TEUSCHER NO. 1	PEPPERS REFINING CO	KB	1144	530	614	6251	325	ER, SP
15N	01W	31	NE	NW	SW		C	B	A		GARLAND NO. 1	HARPER OIL CO.	KB	1124	422	702	6122	203	ER, SP
15N	01W	32	SE	SE	NW		B	D	D		GRANT NO. 1	HARPER OIL CO.	KB	1140	460	680	6166	205	ER, SP
15N	01W	33	SE	SE	NW		B	D	D		GRIFFIN #1A	PELICAN PRODUCTION CO	KB	1147	505	642	5545	104	IEL, SP
15N	01W	34	SE	SE	NW		B	D	D		HOFFMAN #1	BIG CHIEF DRILLING CO	DB	1164	490	674	6042	153	ER, SP
15N	01W	35	SE	SE	SE		D	D	D		YORK NO. 1	JOCELYN-VARN & MELCO	KB	1075	345	730	4580	213	ER, SP
15N	01W	36	SE	NE	NW		B	A	D		SCHOOL LAND #B-1	FORDEE RHOADES OIL CO.	KB	1058	405	653	4486	135	ER, SP
15N	02W	03	NW	NW	SW		C	B	B		GILMORE #1	WESTERN NATURAL RESOURCES	KB	1164	434	730	6207	412	DIL, SP
15N	02W	03	SW	NW	NE		A	B	C		TOM TAYLOR NO. 1	HUMPHREY OIL CO	KB	1098	423	675	4910	260	ER, SP
15N	02W	06	NW	SE	SE		D	D	B		KIESEL #1	W.B. OSBORN	KB	1083	485	598	6244	300	IEL, SP
15N	02W	08	SW	SW	SE		D	C	C		KNEBEL #1	SUNRAY & CALVERT	KB	1118	575	543	5746	261	ER, SP
15N	02W	08	W/2	NW	SE		D	B			MERRY-EBERLE NO. 1-A	WESTERN NATURAL RESOURCES	KB	1115	557	558	5983	490	DIL, GR, SP
15N	02W	09	NE	NE	NE		A	A	A		WARD #1	DAVIDOR & DAVIDOR	KB	1110	460	650	5580	252	ER, SP
15N	02W	10	NW	NE	NW		B	A	B		ALLISON NO. 1	HAP DRILLING CO	KB	1108	455	653	4645	228	ER, SP
15N	02W	11	NE	SE			D	A			WILSON NO. 1	POWEL BRISCOE, INC	KB	1200	560	640	6187	321	ER, SP
15N	02W	12	NE	NE	SE		D	A	A		DURHAM NO. 1	C.H. NICHOLSON CO	KB	1174	520	654	6093	162	ER, SP
15N	02W	13	NE	NE	NW		B	A	A		EGGLESTON #1	D.F. O'ROURKE DRILLING CO	KB	1178	640	538	6181	170	ER, SP
15N	02W	14	NW	SW	NW		B	C	B		ROBERT M. MURRAY #1	HAROLD G. KRAMER	KB	1081	535	546	4594	255	IEL, SP
15N	02W	15	NW	SW	NE		A	C	B		KIGHTLINGER #1	CHAMPLIN OIL & REFINING CO	KB	1085	615	470	4974	253	IEL, SP
15N	02W	16	NE	SE	SE		D	D	A		TROUT-HEIRS #1	HARPER-CHAMPLIN	KB	1137	505	632	6227	200	ER, SP
15N	02W	17	NE	NE	SE		D	A	A		CATHERS #1	R.H. DEARING	DB	1138	545	593	5709	258	ER, SP
15N	02W	19	NE	NW			B	A			SARTAIN #1	HARPER-TURNER ET AL	DB	1038	365	673	6244	216	ER, SP
15N	02W	20	NW	SE	SW		C	D	B		GAFFNEY NO. 1	HARPER-TURNER	KB	1143	484	659	6210	200	ER, SP
15N	02W	21	W/2	NE	NW		B	A			ANDIL #1	HARPER OIL CO.	KB	1142	555	587	6296	416	DIL, GR, SP
15N	02W	23	SW	NE	SW	SE	D	C	A	C	J.B. WARD NO. 1	SOUTHERN UNION EXPLOR	KB	1243	620	623	6280	500	DIL, SP
15N	02W	25	SE	SE	SW		C	D	D		BEEN NO. 1	ASHLAND OIL & REFINING CO	KB	1209	624	585	6234	295	IEL, SP
15N	02W	26	NW	NE	NE		A	A	B		ORNER NO. 1	HARPER-TURNER	KB	1246	548	698	6265	198	ER, SP
15N	02W	27	NW	SW	NE		A	C	B		FANNIE EDWARDS NO. 1	PEPPERS REFINING CO	KB	1169	605	564	6170	403	ER, SP
15N	02W	28	SW	SE	SE		D	D	C		SCHAEFER #2	GENERAL PRODUCTION CO	KB	1160	595	565	6342	239	ER, SP
15N	02W	29	SW	SE	NE		A	D	C		LENTZ NO. 2	HARPER-TURNER	KB	1160	634	526	6047	204	ER, SP
15N	02W	30	NW	SE			D	B			COOPER #1	HARPER-TURNER	KB	1147	590	557	5905	203	ER, SP
15N	02W	32	SW	NW	NE		A	B	C		NORRIS #1	GENERAL DRILLING CO	KB	1153	535	618	5904	203	ER, SP
15N	02W	33	SW	NW	NE		A	B	C		SCHWAKE NO. 1	PEPPERS REFINING CO	KB	1141	555	586	5921	436	ER, SP
15N	02W	35	SW	NW	NE		A	B	C		LYNN #1	PEPPERS REFINING CO	KB	1191	556	635	5841	370	ER, SP
15N	02W	36	NE	NE	SE		D	A	A		RANDLE #1	PEPPERS REFINING CO	KB	1139	568	571	6163	402	ER, SP
15N	03W	13	SW	SW	SW		C	C	C		THREADKILL #1	T.W. EASON	DB	1066	455	611	6303	254	ER, SP
15N	03W	13	NE	SW	SW		C	C	A		WARD NO. 1	KAISER-FRANCIS OIL	KB	1095	545	550	6218	509	DIL, SP
15N	03W	15	SE	SE	NW		B	D	D		BOWEN #1	LANG & UNGER	KB	1056	445	611	6361	308	ER, SP

Township	Range	Section	Spot Location of Well						Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description			USGS Description											
15N	03W	20	NE	SE	NW	B	D	A	WERSHING #1	BRITISH AMERICAN OIL	DB	1024	550	474	6463	227	ER, SP
15N	03W	22	SE	SE	SE	D	D	D	BALLARD #1	RYAN OIL CO.	KB	1086	515	571	6322	236	ER, SP
15N	03W	23	SW			C			KIRKPATRICK NO. 1-23	OKLAND OIL CO.	KB	1068	442	626	4971	409	DIL, SP
15N	03W	23	SE	SW	SW	C	C	D	CAMP #1	SMILEY	KB	1092	630	462	6955	252	ER, SP
15N	03W	24	SE	NW	NE	A	B	D	GIBBENS NO. 1	FORDEE RHOADES OIL CO.	KB	1128	490	638	6255	132	ER, SP
15N	03W	25	SW	SW	NW	B	C	C	BURT #1	HARPER OIL CO.	KB	1101	680	421	6385	400	ER, SP
15N	03W	26	SW	NW	SW	C	B	C	SCHOCK #1	NATIONAL ASSOC. PETR. CO.	KB	1116	625	491	6354	312	ER, SP
15N	03W	27	NE	SE	SE	D	D	A	HELLER NO. 1	NATIONAL ASSOC. PETR. CO.	KB	1122	600	522	6428	312	ER, SP
15N	03W	32	SE	SE		D	D		MARTIN #1	JOSALINE PROD. CO.	KB	1057	573	484	6064	262	ER, SP
15N	03W	34	SE	NE	NW	B	A	D	BOHANON #1	LANG & UNGER	KB	1075	550	525	6251	318	ER, SP
15N	03W	36	NW	NW	NE	A	B	B	FRAIM NO. 1	HARPER OIL CO.	KB	1140	573	567	6401	200	ER, SP
15N	03W	03	W/2	SW	NW	B	C		GOLDIE DREESSEN NO. 1	WIL-MC OIL CORP	KB	1048	315	733	6163	287	IEL, SP
15N	03W	05	NE	NW		B	A		WALTON #1-A	DAVIS BROS.	KB	1067	300	767	6471	234	ER, SP
15N	03W	12	SE	SE	NE	A	D	D	LUCKINBILL #1	STANOLIND OIL & GAS CO	DB	991	518	473	6199	264	ER, SP
15N	03W	35	SW	NE	SW	C	A	C	BROWN #1	THE TEXAS COMPANY	KB	1151	735	416	6489	517	ER, SP
15N	04W	03	NW	SW		C	B		MARGARET #1	MAGNESS PETROLEUM CO	DF	1098	460	638	6965	268	IEL, SP
15N	04W	04	SW	NE	SE	D	A	C	#1 ISABELLE	MAGNESS PETR. ET AL	DF	1103	390	713	6464	248	IEL, SP
15N	04W	05	NW	NW		B	B		BRIDAL NO. 1-A	T.P. PETR. CORP.	GL	1111	700	411	7011	208	IEL, SP
15N	04W	06	NE	NE	NE	A	A	A	MARY WASWO NO. 1	T.P. PETR. CORP.	GL	1117	378	739	6967	221	IEL, SP
15N	04W	08	NW	SE		D	B		NITA #1	YALE OIL ASSOC	KB	1103	395	708	6522	326	ER, SP
15N	04W	09	SW	NW		B	C		CAVANAUGH NO. 1	POWEL BRISCOE, INC	KB	1084	330	754	5558	205	ER, SP
15N	04W	10	SE	SW		C	D		#1 VERNA	MAGNESS ET AL	KB	1052	352	700	6317	264	IEL, SP
15N	04W	11	SW	NW	NW	B	B	C	FAULKNER NO. 1	CALVERT, HUGGMAN & MALLOY	KB	1079	352	727	6719	262	ER, SP
15N	04W	14	SW	SE	NW	B	D	C	CARTER #1	CALVERT DRILLING CO	KB	1018	470	548	6701	253	ER, SP
15N	04W	15	NE	NE	SE	D	A	A	SCHEIHING #1	MACMILLAN PETR. CORP	KB	1018	400	618	6402	260	ER, SP
15N	04W	16	SE	NE		A	D		CAROL #1	MAGNESS & UNION TEXAS	KB	1056	385	671	6377	260	IEL, SP
15N	04W	19	NW	SE		D	B		AMELIA SIGL #1	UNION TEXAS PETROLEUM	KB	1051	605	446	6816	272	IEL, SP
15N	04W	20	NW	SW		C	B		#1 NAKVINDA	UNION TEXAS PETROLEUM	KB	1062	578	484	6554	263	IEL, SP
15N	04W	21	NW	NW		B	B		BLACKWOOD #1	POWEL BRISCOE, INC	KB	1029	637	392	5580	280	ER, SP
15N	04W	22	NW	NE		A	B		#1 GWYN	MAGNESS & WILSHIRE	KB	1016	445	571	6324	246	IEL, SP
15N	04W	23	SW	NW	NW	B	B	C	SEYLLER #1	PEPPERS REFINING CO	KB	1029	435	594	6622	325	ER, SP
15N	04W	27	SE	SE	NW	B	D	D	PLOEGER #1	POWEL BRISCOE, INC	KB	1076	440	636	6365	317	ER, SP
15N	04W	28	NW	NW	SW	C	B	B	SEYLLER #1	TEXAS CALGORY CO	KB	1097	550	547	6495	474	ER, SP
15N	04W	29	NW	SW		C	B		DERR #3	PHILLIPS PETR. CO	DB	1126	720	406	6900	335	ER, SP
15N	04W	30	SW	NW		B	C		MESSENBAUGH #1	SOHIO PETROLEUM CO	DB	1099	615	484	7188	410	ER, SP
15N	04W	31	SW	NE		A	C		BURGE #4	PHILLIPS PETR. CO	DB	1125	680	445	6958	340	ER, SP
15N	04W	33	NE	NW		B	A		LENHART #1	TRIGG DRLG. CO. INC	KB	1076	500	576	6469	162	ER, SP
15N	04W	34	NW	SE		D	B		BRISCOE #1	POWEL BRISCOE, INC	KB	1073	482	591	5509	186	IEL, SP
15N	04W	35	SW	NW		B	C		SIMMONS #1	POWEL BRISCOE, INC	KB	1081	480	601	5791	192	IEL, SP
16N	01E	01	NE	SW	SW	C	C	A	PHILLIPS #1	CLEARY PETROLEUM CORP	DF	1003	730	273	5246	157	DIL, SP
16N	01E	02	SW	SE		D	C		NEWHAUS #1	MAGNESS PETROLEUM CO	KB	1036	632	404	5070	211	IEL, SP
16N	01E	03	SW	NE	NW	B	A	C	GENEVA #1	N.V. DUNCAN DRILLING CO	KB	1011	495	516	5364	147	IEL, SP
16N	01E	04	NW	SE	SW	C	D	B	FURIN-ECKMAN NO. 1	CRESLENN OIL CO.	KB	1068	680	388	5074	298	IEL, SP
16N	01E	05	NW	SE	NW	B	D	B	TERREL NO. 1	JORDAN PETROLEUM CO.	KB	1027	686	341	5440	83	ER, SP
16N	01E	06	NE	SE		D	A		MAGNUS #1	THE WIL-MC OIL CORP	KB	1068	596	472	5503	326	DIL, SP
16N	01E	07	NW	SW	SE	D	C	B	GAFFNEY #1	CAREY TRUST CO	KB	1067	550	517	5542	201	ER, SP
16N	01E	08	NE	NW	NE	A	B	A	ANNA PAUL #1	FAIN PORTER	KB	1120	545	575	5447	165	IEL, SP

Township	Range	Section	Spot Location of Well: Legal Description	Spot Location of Well: USGS Description	Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
16N	01E	09	SE SE SW	C D D	TERELL #1	L.B. JACKSON	KB	1081	623	458	5510	147	ER, SP
16N	01E	10	SE SE NW	B D D	RUTH BENSON #1	H.B. MABEE CO	KB	1050	435	615	5407	313	IEL, SP
16N	01E	11	SE SW NE	A C D	DOWNEY NO. 1	WALTER DUNCAN	KB	1090	760	330	5369	173	ER, SP
16N	01E	12	S/2 NW	B	DERRICK #1	WARD M. EDINGER	KB	1035	740	295	5278	179	ER, SP
16N	01E	14	SE SW	C D	D.R. BROWN #1	RAYMOND OIL CO. INC	KB	1006	630	376	4934	209	IEL, SP
16N	01E	16	SW SE NE	A D C	EVE-STATE 16#1	USSRM CO	KB	1109	800	309	5537	255	IEL, SP
16N	01E	17	NE NE NW	B A A	FRUIN #1	FLOYD HUBBELL & GEO. DECK	KB	1122	450	672	5583	181	ER, SP
16N	01E	18	NW NW NW	B B B	MC CROSKEY #1	TOKLAN PROD. CO.	KB	1157	780	377	5693	162	ER, SP
16N	01E	21	NE NE SW	C A A	BROOKS #1	D.F. O'ROURKE & SUNRAY	KB	1015	640	375	5272	118	ER, SP
16N	01E	22	NW NW NE	A B B	WETZEL #1	SUNRAY OIL CORP	KB	1068	385	683	5484	230	ER, SP
16N	01E	23	SE NE SW	C A D	BREAUX #1	RHOADES OIL CO	KB	979	470	509	5339	166	IEL, SP
16N	01E	25	SE SE SW	C D D	COOPER #1	CYCLONE DRILLING CO.	KB	1019	425	594	5352	158	ER, SP
16N	01E	27	SW NE	A C	CREWS #1	RANDALL R. MORTON	KB	1053	450	603	5359	108	ER, SP
16N	01E	28	SE NE NE	A A D	CROCKETT NO. 1	O.K. OIL OPERATORS	KB	1018	720	298	4853	301	IEL, SP
16N	01E	30	SE SE NE	A D D	JORDAN #1	PACIFIC OIL & GAS CO	KB	967	450	517	4886	222	IEL, SP
16N	01E	31	E/2 SE SW	C D	SMITH NO. 1	C & S ENERGY CORP	KB	1125	790	335	5714	475	DIL, GR, SP
16N	01E	34	NW SW SE	D C B	BARNES #1	CIMARRON PETROLEUM	KB	951	640	311	5404	447	DIL, SP
16N	01E	35	SE	D	HUMPHREY #1	T.N. BERRY & COMPANY	KB	1010	840	170	4953	264	IEL, SP
16N	01E	36	SE SE SE	D D D	SCHOOL LAND #1	ARROW DRILLING CO.	KB	973	810	163	5300	172	ER, SP
16N	01W	01	SE SE NW	B D D	LAMEDA NO. 1	W&W EXPLORATION INC	KB	1127	544	583	5523	333	DIL, GR, SP
16N	01W	02	NE SE SW	C D A	RINGROSE NO. 1	RICHARD W. THOMPSON, INC	KB	1127	647	480	5690	312	DIL, GR, SP
16N	01W	03	SW SW SW	C C C	SHIPMAN #1	LYNN DRILLING CO	GL	1130	610	520	5702	145	ER, SP
16N	01W	04	NW NW SE	D B B	RINGROSE #1	A.A. CAMERON & G.R. SCOTT	KB	1127	735	392	5282	140	ER, SP
16N	01W	05	NW NW SE	D B B	SCHLEMMER #1	CHARLES H. MEE	KB	1135	695	440	5899	160	ER, SP
16N	01W	08	SW NW SW	C B C	BRIEDENTHAL NO. 1	GEORGE J. GREER	KB	1148	745	403	5907	160	IEL, SP
16N	01W	09	NW SE	D B	RICE #1	ADAIR & JENKINS	KB	1156	670	486	3667	122	IEL, SP
16N	01W	10	SW SW SE	D C C	WOOD #1	DAVON OIL & GAS CO	KB	1094	655	439	5709	160	ER, SP
16N	01W	11	NE NW	B A	BACKHUS #1	THE WIL-MC OIL CORP	KB	1112	655	457	5672	368	DIL, SP
16N	01W	12	NE NE NW	B A A	GAFFNEY NO. 1	BARRETT PETR. CO	KB	1141	745	396	4418	123	ER, SP
16N	01W	13	NW NW	B B	MARDELL WOLF NO. 1	GOFF-LEEPER DRILLING CO	KB	1079	595	484	5596	107	IEL, SP
16N	01W	15	NE SE NW	B D A	STINCHCOMB #1	JOSALINE PROD. CO.	KB	1119	725	394	5721	159	ER, SP
16N	01W	16	NE SW SW	C C A	STATE #1	CALCO INC	KB	1156	690	466	5815	173	IEL, SP
16N	01W	17	E/2 NW SE	D B	DETJEN NO. 1-17	AMERICAN TRADING & PROD.	KB	1179	748	431	5871	337	DIL, GR, SP
16N	01W	18	SW SW NE	A C C	HAYES #1	C.R. WALBERT	KB	1207	745	462	5938	220	IEL, SP
16N	01W	19	NW SE	D B	O'DELL #1	WOODS PETROLEUM CO	KB	1112	440	672	5900	252	IEL, SP
16N	01W	21	NE NE SW	C A A	E.J. MURPHY #1	MID-CONTINENT PETR.	KB	1095	635	460	5813	225	ER, SP
16N	01W	23	SE NE	A D	SCANNELL NO. 1-23	CHEYENNE PETROLEUM CO	KB	1082	610	472	5335	268	IEL, SP
16N	01W	27	NE NE NE	A A A	DUNHAM #1	MC CONNELL & PRIOR	KB	1020	605	415	5664	167	ER, SP
16N	01W	28	NW SW NW	B C B	JACQUELINE DYER NO. 1	JERRY SCOTT & TIPPERARY	KB	1041	490	551	5786	419	DIL, GR, SP
16N	01W	29	E/2 SW SE	D C	GATES #1	ROBERT M. JORDAN	DB	1057	440	617	5230	113	ER, SP
16N	01W	29	S/2 SE	D	GATES #1	PACIFIC OIL & GAS CO	KB	1065	395	670	4091	317	IEL, SP
16N	01W	30	SW SW	C C	J.J. CONWELL #1	MIDWEST OIL CORP	KB	1168	498	670	6044	192	IEL, SP, CDL, GR
16N	01W	32	E/2 NE NE	A A	WYLIE #1	ROBERT M. JORDAN	DB	1143	440	703	5791	158	ER, SP
16N	01W	33	NE NW SE	D B A	JOHNSON #2	FLEET DRILLING CO.	KB	1201	625	576	5360	110	ER, SP
16N	01W	34	NW SW NE	A C B	LARY #1	UNIT OPERATIONS, INC	KB	1142	540	602	5294	166	IEL, SP
16N	01W	35	NE SE NE	A D A	BOEDECKER #2	JOHNNY MITCHELL	KB	1135	678	457	5780	202	ER, SP
16N	01W	36	SW SW NW	B C C	STATE LAND #1	WALTER DUNCAN	KB	1107	685	422	5751	127	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
16N	02W	07	NE	SE				D	A				WILLIAMS #1	SUNRAY OIL CO.	DB	1026	410	616	5933	333	ER, SP
16N	02W	10	SE	SE				D	D				WARD #1	FLI-PEL OIL CO	KB	1036	428	608	5812	207	ER, SP
16N	02W	12	SW	SE	NE			A	D	C			ALLA JO NO. 1-12	SAMEDAN OIL CORP	KB	1123	490	633	4875	404	DIL, GR, SP
16N	02W	13	SE	NE	NE			A	A	D			ATKINSON #1	RUSSELL MAGUIRE	KB	1132	445	687	5896	132	ER, SP
16N	02W	14	NW	NE	SE			D	A	B			DETFORD CANNON #1-A	RYAN CONSOLIDATED PETR.	KB	1117	495	622	5906	280	IEL, SP
16N	02W	15	NE	SW	NW			B	C	A			BELYEA UNIT #1	FORDEE RHOADES OIL CO	KB	1030	470	560	5877	252	ER, SP
16N	02W	16	NE	NW	NE			A	B	A			ENGLISH #1	THE DERBY OIL CO	KB	979	390	589	5801	275	ER, SP
16N	02W	20	SE	NE	SE			D	A	D			BACKHAUS #3	L.L. GAGE	KB	1004	420	584	4863	111	IEL, SP
16N	02W	21	SE	NE	SW			C	A	D			PONDS ADDITION NO. 1	DOMESTIC OIL CORP	KB	1058	405	653	4898	270	ER, SP
16N	02W	22	NW	NW	NE			A	B	B			HURLEY NO. 1	HOME STAKE PROD. CO	KB	1101	620	481	4867	269	ER, SP
16N	02W	23	SE	NE	NE			A	A	D			SIECK #1	FOUNDATION OIL CO	KB	1117	480	637	5949	140	ER, SP
16N	02W	26	NE	NE	SW			C	A	A			MOMSEN NO. 1	POWEL BRISCOE	KB	1133	568	565	6037	315	ER, SP
16N	02W	27	NW	SE				D	B				KUBOVEC NO. 1	EASON OIL CO	KB	1091	505	586	4876	250	ER, SP
16N	02W	28	SE	NW	NE			A	B	D			SKEL-HOLMAN NO. 3	EASON OIL CO	KB	1012	478	534	4829	268	IEL, SP
16N	02W	29	SE	NE	NE			A	A	D			KIEFFER #1	PANDA DRILLING CO	KB	980	382	598	4846	251	ER, SP
16N	02W	33	SE	NW	NE			A	B	D			HUTCHISON NO. 1	SKELLY OIL CO	KB	1046	505	541	4862	293	ER, SP
16N	02W	34	NW	SW	NW			B	C	B			GOLSON NO. 3	POWEL BRISCOE	KB	1005	445	560	4837	283	ER, SP
16N	02W	35	NE	NE				A	A				LOGAN SMITH NO. 1	JONES AND PELLOW	KB	1170	660	510	6083	353	IEL, SP
16N	02W	36	NW	SE	NW			B	D	B			STATE #36-1	THE WIL-MC OIL CORP	KB	1193	563	630	6059	312	IEL, SP
16N	03W	08	SW	NW	SW			C	B	C			DAVIS NO. 1	ALPHA PETR. CO	KB	1043	300	743	6341	206	ER, SP
16N	03W	15	NW	SE				D	B				SEEDS NO. 1	RAYMOND OIL COMP	KB	1077	310	767	6221	298	IEL, SP
16N	03W	17	SW	SW	SE			D	C	C			GELLETTE #1	A.R. JORDAN DRLG. CO.	DB	1008	350	658	5818	200	ER, SP
16N	03W	18	NW	NE				A	B				POPE #1	TOTO GAS CO	KB	1072	333	739	6415	234	IEL, SP
16N	03W	19	SE	SE	NW			B	D	D			MAGGIE HALL #1	GULF COAST WESTERN OIL CO	KB	1070	378	692	5958	160	ER, SP
16N	03W	20	SE	SW	NW			B	C	D			NOBLE #1	W.F. CATLETT	KB	1032	434	598	5849	168	ER, SP
16N	03W	21	SE	NW	NW	SE		D	B	B	D		LEEPER #1	LOCATOR'S OIL & GAS, INC	KB	1096	310	786	5054	258	IEL, SP
16N	03W	24	SE	SE				D	D				DUNN NO. 1	CHEROKEE OPERATING CO	KB	1042	445	597	5623	398	DIL, GR, SP
16N	03W	25	SW	SW	SW			C	C	C			DAISY HARLAN NO. 1	GRADY MUSGRAVE	KB	1019.5	320	699.5	5643	153	ER, SP
16N	03W	28	SE	SE	NW			B	D	D			AUSTIN #1	JERNIGAN & MORGAN	KB	1067	400	667	6341	252	ER, SP
16N	03W	29	NE	NE	NW			B	A	A			MARGARET WEBER #1	MITCHELL-GAGE DRLG. CORP	DB	1024	400	624	5802	175	ER, SP
16N	03W	34	NW	NW	SE			D	B	B			CASTLE #1	ALTUS DRILLING CO	KB	1043	420	623	6317	210	ER, SP
16N	04W	03	SW	NE				A	C				KNOWLES #1	DAVON OIL CO	DB	1012	245	767	5015	192	ER, SP
16N	04W	11	NE	NE	SE			D	A	A			BATIN NO. 1	HILL & HILL	DB	991	465	526	4894	208	ER, SP
16N	04W	14	SE	SW	SW			C	C	D			ELLIS #1	RAY P. DIEHL	RT	1014	310	704	6603	255	ER, SP
16N	04W	22	NE	NE	NE			A	A	A			ELLIS NO. 1	RUSSELL S. TARR	KB	1038	290	748	6650	207	ER, SP
16N	04W	23	NE	NE	SW			C	A	A			ROBINSON #1	DOMESTIC OIL CORP	KB	1019	362	657	6611	230	ER, SP
16N	04W	33	SW	NE				A	C				LUCILLE #1	MAGNESS PETROLEUM CO	KB	1028	498	530	6446	263	IEL, SP
16N	04W	34	SW	SW				C	C				SIMONE #1	MAGNESS PETROLEUM CO	KB	1068	510	558	7030	271	IEL, SP
16N	04W	35	SW	NE				A	C				MINNIE ANDERSON NO. 1	JAKE L. HAMON	KB	1059	525	534	6740	335	ER, SP
16N	04W	36	SW	SW	NE			A	C	C			FRED R. HIRZEL #1	RYAN CONSOLIDATED PETR.	KB	1092	530	562	6580	256	IEL, SP
17N	01E	07	SE	NW	SE			D	B	D			COHEE #2	JONES-SHELBURNE ET AL.	KB	875	290	585	4898	172	ER, SP
17N	01E	19	SE	SE	NW			B	D	D			RUSSELL #1	DIRICKSON & LEWIS & LYNN	KB	950	423	527	5343	92	ER, SP
17N	01E	20	NW	NW	SW			C	B	B			SHELTON #1	HENRY, ROBINSEN, ANDREWSKI	KB	954	488	466	5312	137	ER, SP
17N	01E	21	SE	SE	NW			B	D	D			GIDDINGS HEIRS #2	J.G.CATLETT	KB	928	275	653	5129	135	ER, SP
17N	01E	22	SE	SW	NW			B	C	D			BAKER #1	JOSALINE PROD. CO.	KB	928	308	620	5150	140	ER, SP
17N	01E	23	NE	NE	SW			C	A	A			DOBSON #1	HARPER-TURNER	KB	974	390	584	5183	165	ER, SP
17N	01E	24	NW	SW	SW			C	C	B			HUGHES #1	BRITISH AMERICAN OIL	KB	998	370	628	5147	165	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
17N	01E	26	SE	NW	NW			B	B	D			MC CARGO #1	MARSHALL HADDOCK ET AL.	KB	917	475	442	5107	105	ER, SP
17N	01E	29	SE	SE	NW			B	D	D			CHILES #1	H.B. MABEE CO.	KB	1006	496	510	5378	305	IEL, SP
17N	01E	31	SW	SW	NE			A	C	C			DOWNING #1	WESTERN WELLS CO	KB	1008	440	568	4253	245	DIL, SP
17N	01E	32	SW	SW	NE			A	C	C			LITTLE #1	WOODS DRLG. CO	KB	978	382	596	5361	101	
17N	01E	33	NW	SW	SE			D	C	B			CRYSTAL #1	WOODS DRLG. CO	DB	991	418	573	5316	100	ER, SP
17N	01E	34	NW	NE	NW			B	A	B			HAYNES #1	N.V. DUNCAN DRILLING CO	KB	966	305	661	5363	132	IEL, SP
17N	01E	35	SE	SW	NW			B	C	D			HOUSE NO. 2	S.C. CANARY & ASSOC	KB	1014	550	464	4870	157	ER, SP
17N	01E	36	NE	NW	SW			C	B	A			STATE #1	HALLIBURTON OIL	KB	985	603	382	1600	159	IEL, SP
17N	01W	09	SE	SE	SW			C	D	D			KOEHN #1	N.V. DUNCAN & BEN J. TAYLOR	KB	956	245	711	4892	110	ER, SP
17N	01W	11	SW	NE	SE			D	A	C			MOSS #2	DIRICKSON & LEWIS & COBB, JR	KB	905	150	755	4911	97	ER, SP
17N	01W	13	NE	NE	NW			B	A	A			D.L. SMITH #4	EASON OIL CO	KB	973	402	571	5242	209	ER, SP
17N	01W	14	SE	NW	NE			A	B	D			FOUTS #4	AMERADA PETROLEUM CO	DB	903	376	527	5013	213	ER, SP
17N	01W	15	NW	NE				A	B				FLASCH #1	RUSSELL MAGUIRE	KB	959	334	625	5380	121	ER, SP
17N	01W	18	N	SE	SW			C	D				HIRZEL #1	THE WIL-MC OIL CORP	KB	1037	360	677	5543	163	DIL, SP
17N	01W	19	NW	NW	NE			A	B	B			PARKER NO. 1	APA INC. & APACHE OIL	KB	1020	448	572	5619	164	ER, SP
17N	01W	21	SW	SW				C	C				DETJEN #1	BIG CHIEF DRILLING CO	KB	1077	382	695	5295	203	IEL, SP
17N	01W	22	NE	NW				B	A				OTTO #1	BROOKS HALL OIL CO	KB	1009	450	559	4946	284	IEL, SP
17N	01W	25	NW	SE	NW			B	D	B			WASHINGTON NO. 1	MOHAWK DRILLING CO	KB	1064	595	469	5573	132	ER, SP
17N	01W	31	NE	NE	NE			A	A	A			CANNING NO. 1	E.J. ATHENS	KB	1096	495	601	5789	158	ER, SP
17N	01W	32	NE	NE				A	A				WHITELEY #1	SCHERMERHORN OIL CORP	KB	1042	560	482	5723	219	IEL, SP
17N	01W	34	SE	SE	SE			D	D	D			KARL EVANS #1	HILL AND HILL	DB	1083	615	468	5695	164	ER, SP
17N	02W	10	NE	NE	SE			D	A	A			ABRAMS NO. 1	D&L OIL CO. & COBB, JR	KB	1046	267	779	5820	108	ER, SP
17N	02W	12	SW	SE	NE			A	D	C			CARROLL NO. 1	WARREN-BRADSHAW EXP. CO	KB	1032	264	768	5280	200	ER, SP
17N	02W	13	NE	NE	NW			B	A	A			RAY #1	WOODS DRLG. CO	KB	1049	462	587	5235	74	ER, SP
17N	02W	26	SW	NW				B	C				#1 NANCE	OLSON DRLG. CO. & WRIGHT	DB	1054	435	619	5951	253	ER, SP
17N	02W	36	SW	SW	SE			D	C	C			STATE #1	GOFF-LEEPER & G.C. PARKER	KB	1081	310	771	5932	192	ER, SP
17N	03W	02	SW	SW	NW			B	C	C			WELCH #1	FALCON SEABOARD	KB	1044	295	749	6187	169	ER, SP
17N	03W	03	NW	SE	SE			D	D	B			MILLIE NO. 1	DAVON OIL & GAS CO	KB	1074	320	754	6116	133	ER, SP
17N	03W	04	SE	SE	NE			A	D	D			BROWN NO. 1	FALCON SEABOARD	KB	995	245	750	6218	176	ER, SP
17N	03W	06	E/2	NW				B					CURTIS NO. 3	H.B. DAVIDSON	KB	1039	194	845	2570	154	IEL, SP
17N	03W	07	NW	SE	NE			A	D	B			BRIDAL #1	FLEET DRLG. CO	KB	1103	395	708	6459	128	ER, SP
17N	03W	09	SW	SW				C	C				BARTON #1	H.B. MABEE CO.	DF	1103	390	713	5848	203	IEL, SP
17N	03W	10	NW	NW	NE			A	B	B			BOHN NO. 2	E.J. DAVIS	KB	1080	245	835	6185	156	ER, SP
17N	03W	14	NW	NW	NW			B	B	B			GOOCH #1	DAVON OIL & GAS CO	KB	1082	380	702	6211	152	ER, SP
17N	03W	15	NW	NE	NE			A	A	B			DERR #1	DAVON OIL & GAS CO	KB	1073	295	778	4690	162	ER, SP
17N	03W	16	NW	NE	NE			A	A	B			GILLETTE NO. 1	ANDERSON-PRICHARD OIL	KB	1096	352	744	4773	206	ER, SP
17N	03W	18	NE	NE	NW			B	A	A			HOPKINS NO. 1	FLEET DRLG. CO	KB	1112	505	607	6491	179	ER, SP
17N	03W	22	NW	SW	SE			D	C	B			SANDERSON NO. 1	AMBASSADOR OIL CO.	KB	1134	380	754	5001	147	ER, SP
17N	03W	23	NE	NE	NE			A	A	A			GRAVES NO. 1	DAVON DRLG. ET AL.	KB	1123	382	741	6240	105	ER, SP
17N	04W	01	SW	SW	NW			B	C	C			RYLAND NO. 1	GIBRALTAR OIL CO	KB	1117	450	667	4928	203	ER, SP
17N	04W	03	NE	SE				D	A				HOPKINS #1	FOX & FOX	DB	1117	423	694	5041	207	ER, SP
17N	04W	04	NE	NW				B	A				WOLFF NO. 1	L.B. TURK, ET AL	KB	1115	350	765	6101	194	ER, SP
17N	04W	06	SW	NE				A	C				DODD #1	L.C. THAPPE	DB	1161	380	781	6983	211	ER, SP
17N	04W	10	SW	NE				A	C				BLAIR #1	DAVON OIL	DB	1141	465	676	5021	194	ER, SP
17N	04W	11	SE	NW				B	D				RYLAND #1	EASON OIL CO	DB	1144	420	724	4999	254	ER, SP
17N	04W	12	SW	NW	SW			C	B	C			V. ROUT #1	GULF OIL CORP	DB	1135	392	743	4905	240	ER, SP
17N	04W	13	SW	NW				B	C				GRAFF #1	BAHAN BROTHERS	DB	1126	522	604	4950	250	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
17N	04W	14	NE	SW				C	A				MC CONNELL#1	CONTINENTAL OIL CO	DB	1143	442	701	5010	290	ER, SP
17N	04W	15	SW	SE				D	C				GRAFF #2	DAVON OIL	RT	1152	465	687	5053	199	ER, SP
17N	04W	16	NE	NE				A	A				MC CONNELL #1	DAVON OIL CO	DB	1150	368	782	5042	218	ER, SP
17N	04W	21	NE	SE				D	A				MIDDLETON #1	DAVON OIL	DB	1074	380	694	4981	197	ER, SP
17N	04W	22	NW	SW				C	B				NAVE #2	DAVON OIL	RT	1087	340	747	4996	194	ER, SP
17N	04W	23	SW	NE	SW			C	A	C			WELLS #2	DAVON OIL	DB	1032	467	565	5017	202	ER, SP
17N	04W	25	NW	NE	SE			D	A	B			MOORE #1	J.D. WEILER	KB	1099	485	614	4933	173	ER, SP
17N	04W	26	SW	NE	SW			C	A	C			MYERS #3	CONTINENTAL OIL CO	DB	1059	410	649	4951	287	ER, SP
17N	04W	34	NE	NE				A	A				SMITH #1	R.H. DEARING & SON	DB	1060	412	648	4955	221	ER, SP
17N	04W	35	NW	NE				A	B				M.M. SHORE #1	THE TEXAS CO.	DB	1008	345	663	4945	200	ER, SP
18N	01W	27	NE	NE	NE			A	A	A			HENDERSON #1	B.M. HEATH	KB	986	410	576	5562	149	ER, SP
18N	02W	01	S/2	NW	SE			D	B				BRISCOE #2-A	THE WIL-MC OIL CORP	KB	1073	388	685	2313	50	DIL, GR, SP, CDL
18N	02W	05	NE	NW	NE			A	B	A			WROBBLE #1	WAYNE R. ABBOTT	KB	1036	265	771	5927	164	ER, SP
18N	02W	12	NE	NE	NW			B	A	A			BLAKESLEY #1	JAY SIMMONS ET AL	KB	1082	380	702	5821	166	ER, SP
18N	02W	17	NE	NE	SW			C	A	A			SEYLLER NO. 1	JONES-SHELBURNE ET AL	KB	1066	310	756	6087	178	ER, SP
18N	02W	21	NW	SW				C	B				DONOHOE NO. 2	T.P. PETROLEUM CORP.	GL	1056	234	822	5521	194	IEL, SP
18N	03W	01	SE	NW				B	D				HARRIS #1	ATLAS EXPLORATION CO	KB	1114	368	746	5533	162	ER, SP
18N	03W	13	SE	NW				B	D				LEWIS NO. 1	WORLEY & HARRELL	KB	1033	275	758	6173	194	ER, SP
18N	03W	27	SE	SW				C	D				MILLER #1	SENECA OIL CO	KB	1018	275	743	5711	210	IEL, SP
18N	03W	30	NW	SE				D	B				PEARL SMITH #1	ONGC	DB	1043	315	728	4793	208	ER, SP
18N	03W	31	SW	SE				D	C				STOOLFIRE NO. 1	GIBRALTAR OIL CO	KB	1031	215	816	4777	142	ER, SP
18N	03W	31	SE	SE	NE			A	D	D			KERFOOT #1	TRIGG DRLG CO	KB	1041	445	596	6278	207	ER, SP
18N	03W	34	NW	SE	SW			C	D	B			WILSON NO. 1	FALCON-SEABOARD ET AL	KB	1025	270	755	3298	190	ER, SP
18N	04W	05	NW	NW	SE			D	B	B			WAREING #1	ATMAR DRLG. CO & HODGE	KB	1038	150	888	4821	108	ER, SP
18N	04W	16	SE	SE	SW			C	D	D			MC DANIEL #2	CHAMPLIN REFINING CO	KB	1012	277	735	5067	191	ER, SP
18N	04W	17	NE	NE	NE			A	A	A			FICKEN #1	H.E.R. DRLG. CO	KB	1000	175	825	4857	104	ER, SP
18N	04W	21	NE	SW	SW			C	C	A			BLANEY #3	ONGC	KB	1050	320	730	4846	150	ER, SP
18N	04W	22	NE	SW	SW			C	C	A			NORRIS #1	ONGC	KB	1047	312	735	5075	144	ER, SP
18N	04W	27	NW	SW				C	B				VIVIAN #1	BIG CHIEF DRLG. CO	KB	1067	328	739	5124	255	ER, SP
18N	04W	28	NE	NW	NW			B	B	A			RIGDON UNIT #2	ONGC	KB	1066	330	736	4850	155	ER, SP
18N	04W	32	SW	SW	NW			B	C	C			MATHESON #1	NATIONAL ASSOC. PET. CO	KB	1112	370	742	6764	202	ER, SP
18N	04W	33	SW	NE				A	C				RIDGON NO. 1	LON B. TURK ET AL	KB	1112	405	707	6066	200	ER, SP
18N	04W	35	NW	NW				B	B				SCHMIDT #1	FOX & FOX	DB	1062	340	722	4936	307	ER, SP
19N	02W	05	NE	NE	NW			B	A	A			MEYERS NO. 1	JOHNSON & GILL	KB	1153	260	893	5065	100	ER, SP
19N	02W	05	S/2	NE	NE			A	A				BULLING "C" NO. 1	RAMSEY ENGINEERING	KB	1075	206	869	1889	86	DIL, GR, SP, CDL
19N	02W	08	NW	NW	SE			D	B	B			BULLING #1	NOBEL & GUSSMAN	KB	1093	308	785	5395	83	ER, SP
19N	02W	11	SE	SE	NE			A	D	D			THEDFORD NO. 1	RUSSELL MAGUIRE	KB	1117	250	867	5487	169	ER, SP
19N	02W	13	NE	SW	SE			D	C	A			SCHAEFFER NO. 1	WALKER FEAGIN	KB	1112	260	852	5465	226	ER, SP
19N	02W	15	NE	NE	SW			C	A	A			SEIBOLT #2	MC VAY & STAFFORD	KB	1079	205	874	5587	162	ER, SP
19N	02W	23	NW	SW				C	B				KINDSCHI NO. 1	HIAWATHA OIL	KB	1042.6	204	838.6	5501	167	IEL, SP
19N	02W	25	NW	NW	NW			B	B	B			WYANT #1	H.J. PORTER	DB	1075	395	680	5576	110	ER, SP
19N	03W	02	SE	SE	NE			A	D	D			SHARP #1	MERCURY ET AL	KB	1134	395	739	5675	228	ER, SP
19N	03W	03	SE	NE	NE			A	A	D			ZONDLER #1	SUN OIL CO	KB	1163	446	717	5938	273	ER, SP
19N	03W	11	SW	SW	NE			A	C	C			DONAHUE #1	SUN OIL CO	DB	1122	370	752	6035	262	ER, SP
19N	03W	19	SE	SE				D	D				GREENSHIELD NO. 1	LIVINGSTON OIL	KB	1001	305	696	4794	150	ER, SP
19N	04W	01	SE	NE				A	D				POLSLEY NO. 1	HAP DRLG CO	KB	1044	230	814	5202	172	ER, SP
19N	04W	03	SE	SE	NW			B	D	D			BEEBY #1	AN-SON PETR.	KB	1057	255	802	4787	199	ER, SP

Township	Range	Section	Spot Location of Well: Legal Description	Spot Location of Well: USGS Description	Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
19N	04W	08	NW NW SE	D B B	VCULEK NO. 1	MID-AMERICA MINERALS	KB	1022	220	802	5273	163	ER, SP
19N	04W	09	NW NW NE	A B B	BAKER #1	ASHLAND OIL	KB	1058	352	706	4839	259	ER, SP
19N	04W	12	NW SW NE	A C B	O'NEILL NO. 1	MID-CONTINENT	KB	1060	285	775	4710	196	ER, SP
19N	04W	24	NW NW SE	D B B	ACTON #1	J.E. TRIGG	DF	1066	335	731	4931	104	ER, SP
19N	04W	25	SE NW NE	A B D	DIEDRICH #1	C.L. CARLOCK ET AL	KB	1034	302	732	5361	169	ER, SP
19N	04W	27	NE NE SE	D A A	HARMON #1	ALTUS DRILLING	KB	982	295	687	4959	158	ER, SP

REFERENCE DATUM = DATUM FROM WHICH THE LOG FOOTAGE WAS MEASURED
* REFERENCE DATUM ELEVATION ESTIMATED FROM USGS TOPOGRAPHIC MAP

Abbreviations

DIL = DUAL INDUCTION LOG
IEL = INDUCTION ELECTRICAL LOG
ER = ELECTRICAL RESISTIVITY LOG
GR = GAMMA RAY LOG
SP = SPONTANEOUS POTENTIAL LOG
CDL = COMPENSATED DENSITY LOG
CNL = COMPENSATED NEUTRON LOG

GL = GROUND LEVEL
DF = DERRICK FLOOR
BH = BRADEN HEAD
RT = ROTARY TABEL
DB = DRIVE BUSHING

TABLE D3: LIST OF WELL LOGS USED TO MAP THE BASE OF THE USDW IN OKLAHOMA COUNTY
BASE OF USDW DEFINED AS 10,000 mg/L TOTAL DISSOLVED SOLIDS (RESISTIVITY CUT-OFF = 4 OHM-METERS)

Township	Range	Section	Spot Location of Well: Legal Description				Spot Location of Well: USGS Description			Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
11N	01E	01	NE	SW			C	A		GARRETT #1	USSRAM	KB	1148	592	556	6126	298	ER, SP
11N	01E	02	N/2	SE	NE		A	D		KUSEK NO. 1	USSRAM	KB	1117	535	582	5700	303	IEL, SP
11N	01E	06	NE	SE			D	A		LOWRY NO. 1	WARREN DRILLING CO.	KB	1189	810	379	6395	259	IEL, SP
11N	01E	09	SE	NW	SW		C	B	D	HARVEST #1	NORTH STAR	KB	1188	680	508	6068	516	IEL GR, SP
11N	01E	12	NW	NW	NE		A	B	B	JOHNSTON "A" #1	APACHE OIL CORP.	KB	1170	520	650	5773	372	ER, SP
11N	01E	13	NE	NE			A	A		ECHO NO. 1-13	OAK HILLS ENERGY, INC	KB	1125	488	637	5825	420	DIL, GR, SP
11N	01E	14	SW	SE	SE		D	D	C	C.S. DAWSON NO. 1	USSRAM	KB	1143	658	485	6265	284	IEL, SP
11N	01E	15	NW	NW	NE		A	B	B	COOPER #1	HARRY HOLLENBECK	KB	1225	625	600	6466	2900	ER, SP
11N	01E	18	NW	SW	NE		A	C	B	BOHR NO. 1	E.L. COX & J.D. WRATHER	KB	1221	785	436	6486	369	ER, SP
11N	01E	20	SW	SW			C	C		LAGO NO. 1	R.S. BOND & ALTUS	KB	1269	840	429	6068	608	ER, SP
11N	01E	21	NW	NW	NE		A	B	B	SINGER #1	HENRY OIL & GAS INC	KB	1182	690	492	5847	85	IEL, SP
11N	01E	25	SE	NW	NW		B	B	D	HARDER #1	ATLANTIC REFINING CO	DF	1132	545	587	6230	210	ER, SP
11N	01E	26	NW	SW	SE		D	C	B	SKELTON #1	HARPER-TURNER	KB	1146	595	551	6299	202	ER, SP
11N	01E	33	NW	NW			B	B		SANGER NO. 1	REPUBLIC NATURAL GAS	KB	1182	720	462	5985	595	ER, SP
11N	01E	34	SW	SW	NW		B	C	C	GUTHRIE #1	ASHLAND OIL	KB	1192	635	557	6423	292	ER, SP
11N	01W	02	NW	NW	NE		A	B	B	OSBORN NO. 1	REDA PUMP CO	KB	1178	805	373	6609	612	ER, SP
11N	01W	03	NW	SE	SE		D	D	B	WHITEHEAD #1	AMERADA PETR. CORP	KB	1188	840	348	6681	287	ER, SP
11N	01W	07	NE	SE			D	A		LARKIN #1	ZIPHYR DRLG. CO.	KB	1309	950	359	7114	412	ER, SP
11N	01W	11	SW	SW			C	C		LEAVITT NO. 1	MIDSTATES OIL CORP	KB	1244	800	444	6158	657	ER, SP
11N	01W	13	NW	NW	SE		D	B	B	BELAND #1	ROY STARR CO	RT	1269	752	517	6787	250	ER, SP
11N	01W	14	SE	SW			C	D		MC NEW #1	WEBSTER & ASHLAND	KB	1219	895	324	6679	296	ER, SP
11N	01W	15	SE	NE			A	D		POINTON NO. 1	CALVERT DRLG. CO.	KB	1213	950	263	6192	647	ER, SP
11N	01W	22	NE	NE			A	A		LAIN NO. 1	BENSON & MONTIN	KB	1249	1075	174	6197	654	ER, SP
11N	01W	23	SW	NW			B	C		HUFFMAN NO. 1	ASHLAND OIL & REF. CO.	KB	1199	888	311	6157	675	ER, SP
11N	01W	25	SE	SE	SE		D	D	D	CARRIER #1	CONTINENTAL OIL CO.	KB	1175	960	215	6569	368	ER, SP
11N	01W	26	SW	SE	SE		D	D	C	WRIGHT NO. 1	DECEM DRILLING CO	KB	1165	850	315	6662	640	ER, SP
11N	01W	27	NE	NW			B	A		LUNDY NO. 1	CABEEN EXPL. CORP.	KB	1259	1020	239	6860	657	ER, SP
11N	02W	07	SW	SW	NW		B	C	C	HARKEY #1	JAY SIMMONS	KB	1244	1230	14	6529	519	ER, SP
11N	02W	18	NE	NW	NW		B	B	A	TROSPER #1	JAY SIMMONS	KB	1224	1150	74	6494	500	ER, SP
11N	02W	19	NW	SE	NW		B	D	B	FUZZELL NO. 1	FAIN-PORTER DRLG. CORP	DF	1250	1190	60	6099	805	IEL, SP
11N	02W	24	SW	NE	SW	NE	A	C	A	TINKER #1	KERR-MCGEE	KB	1252	1210	42	7162	728	IEL, SP
11N	02W	28	NW	SE			D	B		DIVACKY #1	R.E. HIBBERT	KB	1268	1160	108	6765	663	ER, SP
11N	02W	29	NE	SW	NW		B	C	A	LITTLE #1	KERLYN OIL CO.	DB	1283	1080	203	7045	279	ER, SP
11N	02W	30	SW				C			SANTA FE RR NO. 1-30	OXY USU	KB	1317	926	391	1430	78	DIL, GR
11N	02W	31	SW	NE	SE		D	A	C	VENCL #18	SINCLAIR PRAIRIE OIL CO.	GL	1286	1030	256	4089	360	ER, SP
11N	02W	34	NW	SW			C	B		ORA RICE NO. 1	R.E. HIBBERT	DF	1256	1138	118	7457	667	ER, SP
11N	03W	01	SE	NW	SE		D	B	D	THEIMER #9	CITIES SERVICE OIL CO.	RT	1214	1048	166	6386	313	ER, SP
11N	03W	02	W	SE	SE		D	D		THEIMER #1	BEN CHADWELL ET AL	DB	1218	971	247	3988	238	ER, SP
11N	03W	11	NW	SE	NE		A	D	B	FERNDALE NO. 1	PHILIP BOYLDE, INC	KB	1253	935	318	4118	600	IEL, SP
11N	03W	22	SE	NE	SW		C	A	D	SURBECK NO. A-1	DAVON DRILLING CO.	KB	1250	1003	247	5773	640	ER, SP
11N	03W	23	NE	NE	SE		D	A	A	WERNER FARLEY SWD NO. 4	CITIES SERVICE OIL CO.	KB	1242	998	244	1072	36	ER, SP
11N	03W	24	NW	SW	SE		D	C	B	KUHLHOFF-HENNING #4	I.T.I.O. COMPANY	DB	1294	1000	294	4038	346	ER, SP
11N	03W	26	SE	SE	NE					BILLEN NO. 1	ATHENS PETROLEUM	KB	1265	948	317	821	78	ER, SP
11N	03W	27	NE	NE	SE		D	A	A	CLASSEN #1	CITIES SERVICE OIL CO.	DB	1296	1070	226	6556	860	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
11N	03W	31	SW	SW	NE			A	C	C			SOCHER #1	STAR OIL CO.	DB	1296	1140	156	7878	754	ER, SP
11N	03W	35	N/2	NE	SE			D	A				LORD #1	ROBERT A. MASON	KB	1287	1065	222	6592	65	IEL, SP
11N	03W	36	NE	SE	NW			B	D	A			STATE LAND NO. 2	E.J. ATHENS	KB	1319	1130	189	6567	872	ER, SP
11N	04W	01	NE	NE				A	A				FUSON NO. 1	BRITISH AMERICAN OIL	KB	1195	1025	170	1261	75	ER, SP
11N	04W	07	SE	NE				A	D				SWATEK NO. 1	RATLIFF EXPLORATION	KB	1255	1136	119	8162	820	DIL, SP
11N	04W	08	NW	NW				B	B				HAYES NO. 1	BLACKWOOD & NICHOLS	KB	1242	1060	182	7804	386	ER, SP
11N	04W	10	SW	SE	SE			D	D	C			BOECKING #1	FRANK RUSSELL	DB	1253	1120	133	7400	795	ER, SP
11N	04W	16	SE	NW				B	D				ZURLINE #1	ASHLAND OIL	KB	1287	1095	192	7685	317	ER, SP
11N	04W	18	NE	NE	SE			D	A	A			WINDS WEST NO. 2	WILLIS EXPLORATION	KB	1286	1055	231	8033	852	DIL, SP
11N	04W	19	NE	NW				B	A				CERMAK #1	BIG CHIEF DRILLING CO	KB	1298	1160	138	7861	544	IEL, SP
11N	04W	21	NW	SW				C	B				NICOR NO. 1	NICOR DRILLING CO	KB	1294	1028	266	9466	984	DIL, SP
11N	04W	28	SE	NE				A	D				AIRPORT TRUST "B" #28-1	RATLIFF EXPLORATION CO	KB	1300	1095	205	8168	982	DIL, SP
11N	04W	29	SW	SE				D	C				STONE #1	RATLIFF EXPLORATION CO	KB	1307	1132	175	8206	819	DIL, SP
11N	04W	30	NW	SE				D	B				ROZTOCIL #30-1	RATLIFF EXPLORATION CO	KB	1323	1190	133	8348	962	DIL, SP
11N	04W	31	NE	SE				D	A				WILKERSON #1	RATLIFF EXPLORATION CO	KB	1317	1110	207	8433	788	DIL, SP
11N	04W	32	SE	NW				B	D				OSBORN NO. 1	BLUE QUAIL ENERGY	KB	1306	1180	126	8342	1004	DIL, SP
11N	04W	33	SE	NW	SE	NE		A	D	B	D		AIRPORT TRUST "B" #33-1	RATLIFF EXPLORATION CO	KB	1271	1145	126	8104	970	DIL, SP
11N	04W	36	NE	SW				C	A				STATE TRACT 51#1	STANOLIND OIL & GAS CO.	DB	1299	1095	204	7668	770	ER, SP
12N	01E	02	SE	SE	SW			C	D	D			MILLER #1	STANOLIND OIL & GAS CO.	DB	1182	750	432	6103	260	ER, SP
12N	01E	05	NE	NE	SE			D	A	A			HANSON #1	ANDERSON & CAREY	DB	1182	730	452	5752	120	ER, SP
12N	01E	08	NW	NE	NE			A	A	B			DAVIS #1	AN-SON OIL CO.	DB	1121	590	531	5697	253	ER, SP
12N	01E	09	NE	NE	NE			A	A	A			WITWICKE #1	ANDERSON & CAREY	DB	1203	590	613	6031	155	ER, SP
12N	01E	10	NE	SE				D	A				MIKE MANEK NO. 1	OLIN OIL & GAS CORP	KB	1151	565	586	6077	292	ER, SP
12N	01E	12	SW	SW				C	C				MOON NO. 1	OLIN OIL & GAS CORP	KB	1105	620	485	5612	238	ER, SP
12N	01E	14	NE	SE				D	A				SION-HONEA #1	OLIN OIL & GAS CORP	KB	1095	505	590	6026	250	ER, SP
12N	01E	24	SE	SE				D	D				MARSHALL NO. 1	OLIN OIL & GAS CORP	KB	1083	528	412	5720	260	ER, SP
12N	01E	24	NW	NW	SE			D	B	B			ERTEL NO. 1	BROOKS HALL OIL CO.	KB	1089	410	679	5830	126	IEL, SP
12N	01E	25	NW	NE				A	B				JORSKI NO. 1	O.E. DEMPSEY	KB	1075	552	523	5611	149	ER, SP
12N	01E	26	NW	NW	NE			A	B	B			HORSESHOE #1	EASON OIL CO.	KB	1107	567	540	6078	210	ER, SP
12N	01E	34	SW	SE				D	C				SETH DALE #1B	NORTH STAR	KB	1148	656	492	766	20	IEL, SP, CDL, GR
12N	01E	36	SW	SW				C	C				STATE 36 NO. 1	USSRAM	KB	1110	535	575	5673	317	IEL, SP
12N	01W	02	NW	NW	NE			A	B	B			WELCH NO. 1	E.J. ATHENS PETR. CORP	KB	1156	785	371	6332	205	ER, SP
12N	01W	02	NE	SW				C	A				DELANEY NO. 1	BEARD OIL CO.	KB	1175	852	323	5906	710	DIL, SP
12N	01W	03	SW	NW	SE			D	B	C			BALES NO. 1	BEARD OIL CO.	KB	1217	891	326	6006	740	DIL, SP
12N	01W	07	NE	NW				B	A				MC VICKERS NO. 1	HORNE-ROBINSON-NATHAN	KB	1237	943	294	6109	329	ER, SP
12N	01W	08	SW	SW				C	C				WYMAN #1	KENNETH A. ROGERS	DB	1250	940	310	5206	293	ER, SP
12N	01W	17	NE	NE	NE			A	A	A			KRAMER ESTATE #1	WESTCOTT & NAGLE	DF	1253	920	333	6640	198	ER, SP
12N	01W	23	NW	NW				B	B				DARROW NO. 1	BEARD OIL CO.	KB	1204	1040	164	6115	738	DIL, SP
12N	01W	25	NW	SW	NE			A	C	B			STOCKTON NO. 1	MOHAWK DRLG. CO.	KB	1151	840	311	6539	172	ER, SP
12N	01W	27	SE	SW	NE			A	C	D			NELLIE FRANSSENS #1	GULF CENTRAL PETR. CO	KB	1127	885	242	6564	745	IEL, SP
12N	01W	35	NW	SE	SW			C	D	B			WAYNE ROBERTS #1	THE FEAGIN CO.	KB	1199	840	359	700	30	ER, SP
12N	01W	36	SE	NW				B	D				PEER WYSKUP #1	SUN OIL CO.	KB	1163	850	313	6499	363	IEL, SP
12N	02W	01	SE	NW				B	D				WHITE #1	ALTUS DRILLING CO	DB	1169	910	259	6670	432	ER, SP
12N	02W	02	SW	SW				C	C				VAN OSTRAND #2	BRITISH AMERICAN OIL	DB	1159	947	212	6210	437	ER, SP
12N	02W	03	NE	NE	SW			C	A	A			SEEBECK NO. 1	ROBERT M. JORDAN	DB	1190	1000	190	6280	450	ER, SP
12N	02W	04	NW	NE	SE			D	A	B			MCLEMORE #2	ASHLAND OIL	DB	1202	1020	182	6315	863	ER, SP
12N	02W	05	NW	SW	SW			C	C	B			NELSON #1	DAVID WARSASKI	DB	1132	1018	114	6356	770	ER, SP

Township	Range	Section	Spot Location of Well: Legal Description					Spot Location of Well: USGS Description					Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
12N	02W	06	NW	NE	NE			A	A	B			LITSEY #1	DAVID WARSASKI	DB	1107	957	150	6277	775	ER, SP
12N	02W	07	NW	NE	NE			A	A	B			LAKE ALUMA #1	ALTUS DRILLING CO	DB	1109	1018	91	6364	780	ER, SP
12N	02W	08	NW	SE	SE	SE		D	D	D	B		KRAUSS NO. 1-A	ONEOK RESOURCES CO	KB	1222	974	248	1204	56	DIL, GR, CDL
12N	02W	09	NW	NW	NW			B	B	B			JOHNSON #1	J.E. JACKSON	DB	1193	1110	83	6387	859	ER, SP
12N	02W	10	NW	SE				D	B				HENNING NO. 1	ASHLAND OIL	KB	1163	1100	63	6320	465	ER, SP
12N	02W	11	NW	NW				B	B				FRAZIER #1	BRITISH AMERICAN OIL	DB	1159	1138	21	6221	434	ER, SP
12N	02W	12	NE	NW				B	A				AUBERT MCVICKERS #1	BRITISH AMERICAN OIL	DB	1180	1035	145	6058	437	ER, SP
12N	02W	13	NE	NE				A	A				LEHMER #1	ANDERSON-PRICHARD OIL	DB	1201	945	256	6122	320	ER, SP
12N	02W	14	NW	NW				B	B				KRAMER #1	LELAND FIKES & JOHN PACE	KB	1147	1050	97	6281	448	ER, SP
12N	02W	15	SE	NE				A	D				RAY NO. 1	W.J. O'CONNER	KB	1153	1065	88	6311	395	ER, SP
12N	02W	16	SE	NE				A	D				ROXLEY #1	BRITISH AMERICAN OIL	DB	1149	1070	79	6642	414	ER, SP
12N	02W	22	NW	NE	NE			A	A	B			LEAVITT NO. 1	G.L. REASON	GL	1209	1130	79	6447	9233	ER, SP
12N	02W	23	NE	SW	NW			B	C	A			WEGENER #1	TREND PETROLEUM INCO	KB	1238	1060	178	6467	151	ER, SP
12N	02W	24	NE	NE	NE			A	A	A			WHITT #1	BRITISH AMERICAN OIL	DF	1230	1060	170	6462	217	ER, SP
12N	02W	28	SE	NW				B	D				BOYD #1	BRITISH AMERICAN OIL	DB	1174	1200	-26	6563	420	ER, SP
12N	03W	03	NE	NE	SW			C	A	A			VOSS NO. 1	PEPPERS REFINING CO.	KB*	1157	1069	88	7315	99	ER, SP
12N	03W	13	NW	NW	NW			B	B	B			LINCOLN PARK #1	DOUBLE "R" DRILLING CO	DB	1158	1090	68	6580	763	ER, SP
12N	03W	15	NW	SW	SE			D	C	B			GUTHRIE #1	CLARK OIL & GAS CO.	DB	1193	980	213	4129	140	ER, SP
12N	03W	23	NW	NW	NW	NW	SE	D	B	B	B	B	BRADEY TELLIER NO. 1	BRITISH AMERICAN OIL	KB	1175	1065	110	8592	220	ER, SP
12N	03W	26	NW	SE	SE	NW		B	D	D	B		COTNER #1	HARPER TURNER ET AL	DB	1231	1127	104	6563	622	ER, SP
12N	03W	34	NW	SE	NW	SE		D	B	D	B		CAREY NO. 6	PEPPERS REFINING CO.	DB	1205	878	327	1139	256	ER, SP
12N	03W	35	NW	NE	SW			C	A	B			COMPRESS #1	ELLISON & PORTMAN	DB	1190	900	290	1041	90	ER, SP
12N	04W	03	SW	SW				C	C				SHELLENBARGER B-1	STANOLIND OIL & GAS CO.	DB	1289	1003	286	7124	860	ER, SP
12N	04W	04	SE	SW				C	D				TOM TOM RANCH #2	BRITISH AMERICAN	DB	1276	1032	244	7193	844	ER, SP
12N	04W	09	SW	NE				A	C				HALBERT UNIT B #1	STANOLIND OIL & GAS CO.	DB	1304	980	324	7249	893	ER, SP
12N	04W	10	SE	NE	SW			C	A	D			CLAUSEWITZ #1	STANOLIND OIL & GAS CO.	DB	1305	1030	275	7157	802	ER, SP
12N	04W	22	SE	SE	NW			B	D	D			COOK UNIT #1	BAY PETROLEUM ET AL	DB	1304	1120	184	7520	910	ER, SP
12N	04W	27	SE	NE	NW			B	A	D			#1 GREGORY	BAY PETROLEUM	KB	1300	1070	230	7291	866	ER, SP
13N	01E	01	NW					B					RUTLEDGE #1	THE SUPERIOR OIL CO.	KB	969	370	599	5199	258	IEL, SP
13N	01E	02	NW	NW	SE			D	B	B			BOOHER #1	E. MESSENGER OIL. CO	KB	1002	435	567	5489	164	ER, SP
13N	01E	04	NW	NW	SW			C	B	B			KEATING #1	WOODS OIL & GAS INC.	KB	962	395	567	5515	155	ER, SP
13N	01E	06	SW	SE	NW			B	D	C			ARMSTRONG #1	SUNRAY OIL CO.	DB	1035	540	495	5889	214	ER, SP
13N	01E	07	NW	NE				A	B				VOREL #1	E.C. CLAY & SON	KB	949	420	529	5844	258	IEL, SP
13N	01E	09	SE	NW	NE			A	B	D			MISSISSIPPI POLLARD #1	RAYMOND OIL CO.	KB	1060	440	620	5546	200	IEL, SP
13N	01E	10	SE	SE	NW			B	D	D			LYDIA MAY #1	THE TEXAS CRUDE OIL CO	KB	953	465	488	5735	235	ER, SP
13N	01E	11	NE	NW	NW			B	B	A			BRAWDY #1	WOOD OIL CO.	KB	1033	500	533	5783	187	ER, SP
13N	01E	12	NE	NW				B	A				OLSEN NO. 1	E. MESSENGER OIL. CO	KB	1050	422	628	5445	206	IEL, SP
13N	01E	13	SW	NE	NE			A	A	C			PEITCHINSKY #1	HALL-JONES OIL CORP.	KB	1031	432	599	5117	167	IEL, SP
13N	01E	14	SW	SW	SW			C	C	C			BOOHER #1	MAGNOLIA PETROLEUM CO.	DB	1065	657	408	4701	410	ER, SP
13N	01E	15	NW	NE				A	B				BOOHER NO. 1	MAGAW & ZIMMER	KB	1037	478	559	5131	460	DIL, SP, CDL, GR
13N	01E	19	S	SW	SE			D	C				O.K. HARRISON NO. 1	TENNECO OIL CO.	KB	1142	700	442	5776	502	IEL, SP
13N	01E	20	SE	NW	SW			C	B	D			VICKERS #3	C.M. HARRIS	KB	1102	620	482	4897	164	ER, SP
13N	01E	21	NW	SW				C	B				VAILS NO. 3	LOBAR OIL CO	KB	1050	485	565	4769	165	ER, SP
13N	01E	22	SE	SE	SW			C	D	D			DAVIS #2	BIG CHIEF DRILLING CO	DB	1066	550	516	4696	157	ER, SP
13N	01E	23	NE	NW	SE			D	B	A			HAMES NO. 1	GLENWOOD OIL CO.	KB	998	590	408	4611	132	ER, SP
13N	01E	24	NE	NE	NE			A	A	A			BEDNAR #1	R. MAGUIRE & ALTUS DRLG	DB	966	490	476	4554	132	ER, SP
13N	01E	25	NE	NW	SW			C	B	A			BABIAK #2	SINCLAIR PRAIRIE OIL CO	GL	991	515	476	4536	233	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
13N	01E	26	SE	SW				C	D				FORTELNEY NO. 1	NATIONAL ASSOC. PETR. CO.	KB	1025	428	597	5875	256	IEL, SP
13N	01E	27	SE	SW	SW			C	C	D			PERISHO #1	HAROLD F. WESTCOTT	DB	1048	545	503	4672	90	ER, SP
13N	01E	28	SW	SE	SW			C	D	C			HUGHES NO. B-3	SINGER	DB	1159	620	539	4874	193	ER, SP
13N	01E	29	SE	NW	SE			D	B	D			LOVELL #1	ALTUS DRILLING CO.	DB	1170	652	518	4896	129	ER, SP
13N	01E	30	SW	SE	SE			D	D	C			PERRY #1	THORPE & HUSKEY	DB	1160	695	465	6111	127	ER, SP
13N	01E	32	W	SE	SW			C	D				ROWLEN #3	LOBAR OIL CO	KB	1138	605	533	4949	165	ER, SP
13N	01E	33	SE	SW	NE			A	C	D			PENDLEY #5	LOBAR OIL CO	KB	1141	603	538	4841	166	ER, SP
13N	01E	34	E	W	SE	NW		B	D				WOLOSZYN #6	WICO OIL CO.	KB	1137	648	489	4818	164	ER, SP
13N	01E	36	NE	NW	SW			C	B	A			GRAFF #1	GEORGE J. GREER	KB	1041	480	561	5946	163	ER, SP
13N	01W	01	SE	SE	NW			B	D	D			A-MACKLIN #1	STANOLIND OIL & GAS CO	DB	1031	488	543	5934	228	ER, SP
13N	01W	02	N	SW				C					KINGSIZE #1	PCX CORP	KB	1051	650	401	5598	544	DIL, SP, CDL, GR
13N	01W	03	SW	NE				A	C				HILL #1	HEARTLAND	KB	1052	630	422	6027	392	IEL, SP
13N	01W	04	SE	SE	SE			D	D	D			ELLIS TRUST NO. 1	APACHE & A.P.A.	KB	1091	675	416	5699	366	ER, SP
13N	01W	04	E/2	SW	SE			D	C				HIWASSEE 1-4	COASTAL OILS	KB	1045	608	437	799	58	DIL, SP CCL, GR
13N	01W	05	NW	SW	NE			A	C	B			FLEETWOOD NO. 1	J.M. HUBER CORP.	KB	1121	834	287	6197	338	ER, SP
13N	01W	06	SW	SE	NW			B	D	C			CHITWOOD 6-1	TITAN OIL & GAS CORP.	KB	1108	754	354	1024	55	IEL, GR
13N	01W	06	S/2	NW	SE			D	B				LEESE #6-1	ALEXANDER ENERGY	KB	1084	683	401	1126	72	DIL, GR, SP, CDL
13N	01W	13	NW	NW	SE			D	B	B			B.H. MEARS NO. 1	SUMMIT & W.J. MARTEN	KB	1087	602	485	6070	198	ER, SP
13N	01W	19	SE	NE	SE			D	A	D			KATIE J #1-19	ALPINE INC.	KB	1182	836	346	1248	10	IEL, GR
13N	01W	24	NE	NW	SW			C	B	A			MARTIN #1	OTSTOT-GUTOWSKY	DB	1230	800	430	6230	200	ER, SP
13N	01W	25	NW	SE				D	B				GUNN #1	LOBAR OIL CO.	KB	1159	720	439	5886	565	IEL, SP
13N	01W	28	SE	NE	NE			A	A	D			HOPCUS NO. 1	WARREN DRILLING CO	KB	1125	820	305	5973	262	IEL, SP
13N	01W	29	NE	NE	NW			B	A	A			HUNT #1	ACE GUTOWSKY	RT	1144	980	164	6448	394	ER, SP
13N	01W	34	SW	SW	NW			B	C	C			HARDACKER #1	E.J. ATHENS PETR. CORP	KB	1157	980	177	6333	113	ER, SP
13N	01W	36	NE	NW				B	A				WILSON #1	EL DORADO DRILLING, INC	KB	1109	712	397	5878	648	DIL, SP
13N	02W	01	NW	NE				A	B				RUBLE NO. 1	PETROLEUM, INC.	KB	1049	791	258	6792	353	ER, SP
13N	02W	04	NW	SW				C	B				LIMERICK NO. 1	HARPER-TURNER	KB	1141	990	151	6503	207	ER, SP
13N	02W	05	NE	NE				A	A				JACK NO. 1	HARPER-TURNER	KB	1114	1040	74	6509	200	ER, SP
13N	02W	06	SW	NW	NW			B	B	C			LISTEN #1	FOX & FOX	RT	1143	900	243	6783	259	ER, SP
13N	02W	14	NW	NE	SW			C	A	B			AVERY NO. 1-14	AUSTRAL OIL CO., INC	KB	1140	938	202	6513	824	IEL, SP, CDL, GR
13N	02W	17	SW	SE				D	C				JESSE #1	GULF OIL CORP.	DB	1108	975	133	6341	421	ER, SP
13N	02W	19	SW	SE				D	C				J.C. JONES #1	AMERADA PETR. CORP.	B	1059	960	99	6178	586	ER, SP
13N	02W	20	SW	SE				D	C				ADAM #1	SKELLY OIL CO.	DB	1046	970	76	808	36	ER, SP
13N	02W	20	SW	SW				C	C				PARK ESTATE #1	GULF OIL CORP.	RT	1082	920	162	6151	406	ER, SP
13N	02W	21	SW	SW				C	C				LAIR ESTATE 31	ONGC	DB	1054	900	154	6171	426	ER, SP
13N	02W	22	SE	NW				B	D				BENNETT NO. 1	DAVON DRILLING CO.	KB	1107	995	112	6682	813	ER, SP
13N	02W	23	NE	NE				A	A				NYSWONGER NO. 1	FEDERAL PETROLEUM INC	KB	1198	890	308	6235	815	IEL, SP
13N	02W	26	NW	SW	SW			C	C	B			MACKLANBURB #1	PEPPERS REFINING CO.	DB	1169	947	222	6646	447	ER, SP
13N	02W	27	NW	NE				A	B				SWEARINGEN #1	YOUNGBLOOD & YOUNGBLOOD	KB	1182	950	232	6697	808	ER, SP
13N	02W	28	SW	NW				B	C				DRAMACK #1	PEPPERS REFINING CO.	DB	1068	939	129	6379	610	ER, SP
13N	02W	29	SW	SW				C	C				LEONARD #1	SKELLY OIL CO.	DB	1048	967	81	6184	842	ER, SP
13N	02W	31	NW	NW	NW			B	B	B			MILEY #1	GULF OIL CORP.	DB	1126	1020	106	6362	836	ER, SP
13N	02W	32	SW	SE				D	C				HAYS #1	PEPPERS REFINING CO.	DB	1151	1050	101	6283	687	ER, SP
13N	02W	34	NW	SW	SW			C	C	B			EDWARDS #1	PEPPERS REFINING CO.	DB	1167	1080	87	6231	100	ER, SP
13N	03W	02	NE	NE	SE	SW		C	D	A	A		JACKSON #2B-4	PETROCORP	KB	1182	920	262	1150	52	DIL, GR
13N	03W	03	N/2	SE	NE			A	D				SUPERIOR NO. 1-3	BOSWELL ENERGY	KB	1162	930	232	1033	46	DIL, GR, SP
13N	03W	04	NW	SW				C	B				GRACE BAPTISTE #1	POWEL BRISCOE, INC	KB	1110	840	270	6403	558	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
13N	03W	05	NE	NE				A	A				E.A.FARRIS #1	POWEL BRISCOE INC.	KB	1121	840	281	6400	303	ER, SP
13N	03W	06	NE	NE	SE			D	A	A			SCHARDT #1	FALCON-SEABOARD	KB	1156	793	363	6701	293	ER, SP
13N	03W	08	NE	SE	SW			C	D	A			HENNEY #1	FALCON-SEABOARD	KB	1124	770	354	6769	322	ER, SP
13N	03W	09	NW	SE	NE			A	D	C			WALDREP NO. 1	REPUBLIC NATURAL GAS	KB	1137	908	229	6912	605	ER, SP
13N	03W	10	NE	SW				C	A				JETER NO. 1	DAVON DRILLING CO.	KB	1168	960	208	6493	462	ER, SP
13N	03W	11	E/2	SW	SW	NE		A	C	C			WYNN ONE #1-11	GULF PRODUCTION CORP.	KB	1180	874	306	1250	50	DIL, GR, SP
13N	03W	16	NW	NW	NW			B	B	B			BUXTON #1	SINCLAIR PRAIRIE OIL CO.	DF	1135	955	180	6931	645	ER, SP
13N	03W	17	N/2	S	NE			A					CORBETT #3	SINCLAIR PRAIRIE OIL CO.	DB*	1161	998	163	6670	495	ER, SP
13N	03W	20	SE	SW	SW			C	C	D			MCGRUE #2	JOSALINE PRODUCTION CO	DB	1185	898	287	2208	42	ER, SP
13N	03W	21	NE	NW	SW			C	B	A			COLLEGE PARK #1	KERLYN OIL CO.	DF*	1180	990	190	6750	634	ER, SP
13N	03W	22	NE	SE				D	A				DELMER E. SMITH NO. 1	CHAMPLIN REF. CO.	BH	1132	1060	72	6486	916	ER, SP
13N	03W	24	NW	NW	SE			D	B	B			CRUM NO. 1	ACE GUTOWSKY	DB	1149	1025	124	6948	328	ER, SP
13N	03W	25	NW	SW	NE			A	C	B			KNOL #1	SKELLY OIL CO.	DB	1159	1030	129	6407	639	ER, SP
13N	03W	26	SW	SW	NE			A	C	C			TRINITY NO. 1-26	POST OAK OIL CO.	KB	1191	995	196	6567	900	DIL, SP
13N	03W	29	NW	NW	NW			B	B	B			OWENS #1-A	KWB OIL PROP. MGT. INC.	KB	1193	938	255	1331	48	DIL, GR
13N	04W	01	NW	SW				C	B				GOAD NO. 1	T.P. PETROLEUM CORP.	GL	1104	750	354	5916	250	ER, SP
13N	04W	02	NE	NE	SW			C	A	A			BIERSCHENK B-1	CHAMPLIN OIL & REFINING CO.	DB	1072	680	392	6794	322	ER, SP
13N	04W	03	NW	SE				D	B				BIERSCHENK #2	DENVER PROD. & REF. CO.	DB	1078	720	358	6615	243	ER, SP
13N	04W	04	NW	SE				D	B				BARBER #1	DENVER PROD. & REF. CO.	DB	1132	853	279	6840	196	ER, SP
13N	04W	05	SE	NW				B	D				GENZER #2	SOHIO PETROLEUM CO.	DB	1084	763	321	7099	423	ER, SP
13N	04W	06	NE	NW				B	A				MEEKER #1	FOX-SCHMITZ	DB	1080	740	340	7076	308	ER, SP
13N	04W	08	NW	SE				D	B				PORTER PAUL #1	GULF OIL CORP.	DB	1152	810	342	7105	410	ER, SP
13N	04W	09	SE	NW				B	D				HARDY #6	SOHIO PETROLEUM CO.	DB	1146	830	316	7128	397	ER, SP
13N	04W	10	NW	SE				D	B				MEEKER #2	H.H. WAGENER	DB	1086	700	386	6699	405	ER, SP
13N	04W	11	NW	SW				C	B				COLLETT B #1	DENVER PROD. & REF. CO.	DB	1084	720	364	6828	264	ER, SP
13N	04W	15	SW	NW				B	C				MCCLURE #2	MIDSTATES OIL CORP.	DB	1121	750	371	6831	390	ER, SP
13N	04W	17	NW	NE				A	B				CROOKHAM BROS #3	ANDERSON-PRICHARD OIL	DB	1166	860	306	7009	374	ER, SP
13N	04W	19	SW	SE				D	C				INES BAILEY#1	DENVER PROD. & REF. CO.	DB	1211	900	311	7608	248	ER, SP
13N	04W	20	SE	NW				B	D				HASEL N. EDNEY #1	STANOLIND OIL & GAS CO.	DB	1194	960	234	7010	468	ER, SP
13N	04W	21	SW	NW				B	C				PERDUE #3	ANDERSON-PRICHARD OIL	DB	1179	850	329	7040	398	ER, SP
13N	04W	23	SE	NE	SW			C	A	D			COPR 1-23D	GULF PRODUCTION CORP.	KB	1163	792	371	1230	60	IEL
13N	04W	28	SW	NE				A	C				B.A. PARMAN #B-2	STANOLIND OIL & GAS CO.	DB	1137	825	312	7199	499	ER, SP
13N	04W	33	NW	NE				A	B				URSCHEL #1	STANOLIND OIL & GAS CO.	DB	1203	965	238	7081	774	ER, SP
13N	04W	34	SW	NW				B	C				ANDERSON #1	MIDSTATES OIL CORP	DB	1197	925	272	6983	828	ER, SP
14N	01E	01	SE	NW	SE			D	B	D			MITCHELL#3	ROBERT M. JORDON	KB	913	310	603	3938	117	ER, SP
14N	01E	03	NW	NW				B	B				LOREN BRISCOE #1	J.A. CHAPMAN	KB	908	250	658	4131	139	ER, SP
14N	01E	04	NE	NE				A	A				JOHN H. STOVER NO. 1	J.A. CHAPMAN	KB	948	265	683	5461	135	ER, SP
14N	01E	05	SE	NW	SW			C	B	D			MEYER NO. 1	POWEL BRISCOE	KB	1079	403	676	4440	194	ER, SP
14N	01E	06	SE	NE	SE			D	A	D			OLSEN NO. 1	POWEL BRISCOE	KB	1055	350	705	4430	220	ER, SP
14N	01E	07	SE	SE	SE								NINA ROGERS NO. 1	INTERNATIONAL HYDROCARBONS	KB	1036	338	698	4493	275	DIL, GR, SP
14N	01E	08	SW	SW	NW			B	C	C			BUZZARD #1	ROBERT M. JORDON	KB	1016	303	713	5349	98	ER, SP
14N	01E	09	SW	NE	NE			A	A	C			CANADA #1	J.A. CHAPMAN	KB	1003	273	730	4329	210	IEL, SP
14N	01E	10	NW	NW	NW			B	B	B			COLE NO. 1	J.A. CHAPMAN	KB	933	250	683	5623	160	ER, SP
14N	01E	14	NE	SE	SW			C	D	A			HENNESSEY NO. 1	N.T. SMITH	KB	905	255	650	5256	153	ER, SP
14N	01E	15	SW	NW	SW			C	B	C			NENNESSEY NO. 1	PROVINCIAL OIL CORP.	KB	955	275	680	5659	172	ER, SP
14N	01E	16	SW	SW	SE			D	C	C			SCHOOL LAND NO. 1	J.A. CHAPMAN	KB	1031	325	706	5772	231	IEL, SP
14N	01E	18	NE	NW	NE			A	B	A			M.W. ROGERS #3	GLENN McCARTHY INC.	KB	977	310	667	4438	133	ER, SP

Township	Range	Section	Spot Location of Well										Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
			Legal Description					USGS Description													
14N	01E	19	SW	SW	SW			C	C	C			TANSEL #1	WILLIAM R. WHITTAKER CO.	KB	1003	525	478	5833	221	ER, SP
14N	01E	20	NE	NE	NW								ELSON #1	DAVON OIL & GAS CO.	KB	997	403	594	5764	156	ER, SP
14N	01E	22	SE	SE	SE			D	D	D			ARTHUR #1	DOUBLE "R" DRLG. CO	DB	978	360	618	5701	200	ER, SP
14N	01E	23	NE	NW	SW			C	B	A			FILSON #1-23	HALL-JONES OIL CORP.	KB	985	265	720	5369	209	IEL, SP
14N	01E	23	NE	NW	NE			A	B	A			EASON NO. 1	N.T. SMITH	KB	954	303	651	5661	166	ER, SP
14N	01E	24	NE	SE									CLARK #1	REX R. MOORE, JR.	KB	1024	340	684	5666	271	IEL, SP
14N	01E	26	NE	NW				B	A				JUNE #1	SENECA OIL CO	KB	1029	432	597	5418	208	IEL, SP
14N	01E	27	NE	NW	NE			A	B	A			MARTIN NO. 1	HEADINGTON OIL CO. ETAL	KB	921	427	494	5634	278	ER, SP
14N	01E	30	NE	NE	NW			B	A	A			TANSEL NO. 1	R. STENZEL	KB	937	440	497	5722	254	ER, SP
14N	01E	31	NE	NE	SE			D	A	A			BRITTON #1	FULLERTON OIL CO.	KB	1031	580	451	5860	228	ER, SP
14N	01E	33	NE	NE	NE			A	A	A			COOPER NO. 1	VIERSEN & COCHRAN	KB	994	360	634	5108	267	ER, SP
14N	01E	34	SE	NE	NE			A	A	D			RINEHART NO. 1	G.A. BROWN	KB	914	370	544	5656	130	ER, SP
14N	01W	01	NE	NE	SW			C	A	A			RINGER #1	MIDSTATES OIL CORP.	KB	1035	317	718	4551	172	ER, SP
14N	01W	03	NE	SE	NW			B	D	A			WALKER #1	MOORE & MILLER	KB	1176	440	736	5028	297	IEL, SP
14N	01W	04	SE	NE	SE			D	A	D			LILLIE PIERSOL #1	DOUBLE "R" DRILLING COMPANY	DB	1115	457	658	5961	280	ER, SP
14N	01W	05	SE	SE				D	D				DONNELL #2	BILINDA PETROLEUM COMPANY	KB	1041	272	769	5964	342	IEL, SP
14N	01W	06	SW	SE				D	C				BALLEW #1	CURT D. EDGERTON	KB	1128	410	718	6167	289	ER, SP
14N	01W	07	SW	SW	SW	NE		A	C	C	C		WATER WELL TEST #1	LAZY E	GL*	1135	426	709	613	8	ER, GR, SP
14N	01W	09	NW	NW	SE			D	B	B			BAKER #1	APPLETON OIL COMPANY	KB	1053	450	603	6130	420	IEL, SP
14N	01W	12	SW	SW				C	C				RUBLE #1	R.J. FIELD	KB	1041	460	581	5445	303	IEL, SP
14N	01W	13	SW	SW	NE			A	C	C			BURGE NO. 1-13	STATEX PETROLEUM INC.	KB	1062	460	602	5911	327	DIL, GR, CDL
14N	01W	14	SE	SE	SW			C	D	D			CONN #1	R.M. JORDAN	DB	1111	553	558	5964	112	ER, SP
14N	01W	15	SW	NE	NE			A	A	C			WALKER NO. 1	A.R. JORDAN	DB	1165	630	535	5983	308	ER, SP
14N	01W	17	SE	SE	SW			C	D	D			TOWE #1	ORAS A. SHAW	KB	1082	705	377	6111	215	ER, SP
14N	01W	18	SE	SE	SW			C	D	D			BURTON NO. 1	SENECA OIL COMPANY	KB	1031	670	361	6142	168	ER, SP
14N	01W	19	SE					D					MASON #1	BILL LONDON	KB	1050	744	306	803	55	DIL, GR, SP
14N	01W	20	NE	SE	NE			A	D	A			HENSLEY #1	ORAS A. SHAW	KB	997	680	317	5995	247	ER, SP
14N	01W	22	SE	NW				B	D				KROH-DULANEY NO. 1	LARIO OIL & GAS CO	KB	1105	810	295	6045	623	DIL, SP
14N	01W	23	NE	NE	SE			D	A	A			MARCEL 31	ROBERT M. JORDAN	KB	1035	580	455	5902	108	ER, SP
14N	01W	24	SE	SE	SW			C	D	D			HAMEY #1	ROBERT M. JORDAN	KB	962	500	462	5797	173	ER, SP
14N	01W	25	SE	SW	SW			C	C	D			VARNUM #1	VICKERS PETROLEUM COMPANY	DB	980	650	330	5873	287	ER, SP
14N	01W	28	NE	NE				A	A				WETZEL #1	MOORE, MOORE & MILLER	KB	957	590	367	5923	205	IEL, SP
14N	01W	30	SW	SE	NE			A	D	C			OWENS #1	PTAK PETROLEUM COMPANY	DB	964	675	289	6240	235	ER, SP
14N	01W	36	NW	NW				B	B				DAVIS #1	HEARTLAND	KB	992	620	372	5881	308	IEL, SP
14N	02W	01	SW	SW	SW			C	C	C			LOOFBOURROW #1	SINCLAIR OIL & GAS CO.	GL	1149	470	679	5885	252	ER, SP
14N	02W	02	NE	SW				C	A				TEUSHER #8	BOB WHITE PRODUCTION	KB	1088	386	702	632	56	IEL
14N	02W	03	SE	NE	SE			D	A	D			DUNCAN LLOYD NO. 4	HARPER-TURNER	KB	1102	528	574	6194	207	ER, SP
14N	02W	04	NE	SW	SE			D	C	A			JULIUS NO. 1-A	HARPER-TURNER	KB	1082	560	522	6313	200	ER, SP
14N	02W	05	SW	SW				C	C				GEORGE MAIER NO. 1	ASHLAND OIL & REFINING COMPANY	KB	1166	590	576	6453	279	ER, SP
14N	02W	06	NW	NW	SE			D	B	B			SHANNON #1	ASHLAND OIL & REFINING COMPANY	KB	1186	605	581	5976	224	ER, SP
14N	02W	07	NW	NW				B	B				JOHN WILSON NO. 1	HARPER-TURNER	KB	1186	735	451	6509	202	ER, SP
14N	02W	08	SW	NW	NE			A	B	C			BOLES NO. 2	HARPER-TURNER	KB	1179	640	539	5928	206	ER, SP
14N	02W	09	NE	NE	NW			B	A	A			TRUSKEY #2	HARPER-TURNER	KB	1123	585	538	5914	203	ER, SP
14N	02W	10	NE	NE	SE			D	A	A			MASON #2	HARPER & TURNER	KB	1126	627	499	6221	201	ER, SP
14N	02W	11	SE	NE	NW			B	A	D			SHELDON #4	HARPER-TURNER	KB	1140	667	473	6229	220	ER, SP
14N	02W	12	NW	NW	NW			B	B	B			KUNDERER #1	HARPER-TURNER ET AL.	KB	1143	473	670	6269	191	ER, SP
14N	02W	13	SW	SW	NW			B	C	C			DUNLAP #1	ROBERT M. JORDAN	DB	1095	884	211	5843	144	ER, SP

Township	Range	Section	Spot Location of Well: Legal Description				Spot Location of Well: USGS Description				Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
14N	02W	15	NW	SE	SE		D	D	B		OLSON #1	STERLING OIL	KB	1036	645	391	6179	200	ER, SP
14N	02W	16	SE	SE	NE		A	D	D		NO. 1A DUNCAN	HARPER-TURNER ET AL.	DB	1029	730	299	6180	338	ER, SP
14N	02W	18	NE	NW	SW		C	B	A		RUTH NO. 1	HARPER-TURNER	KB	1111	660	451	6413	204	ER, SP
14N	02W	19	SE	SE	SW		C	D	D		KIGHTLINGHER #1	HARPER -TURNER	DB	1213	810	403	6664	207	ER, SP
14N	02W	20	NW	SW			C	B			CLARA WILSON #2	HARPER-TURNER	DB	1166	715	451	5976	400	ER, SP
14N	02W	21	NE	SE	NW		B	D	A		WOOD B #2	BAY PETROLEUM CO	DB	1117	820	297	5902	304	ER, SP
14N	02W	22	NE	NE	NW		B	A	A		WOODRUFF A #1	HARPER OIL CO.	KB	1064	770	294	6219	321	ER, SP
14N	02W	23	SE	SE	SE		D	D	D		CHARLES R. MASON #1	HARPER OIL CO.	KB	990	680	310	6138	323	ER, SP
14N	02W	24	SE	SE			D	D			OLSON #1	HALL-JONES OIL CORP.	KB	1068	740	328	6161	250	ER, SP
14N	02W	25	NW	NW	SE		D	B	B		KENNARD #1	ROBERT M. JORDON	DB	1051	690	361	6213	230	ER, SP
14N	02W	26	SE	NE	SE		D	A	D		TALLANT NO. 1	HARPER-TURNER	KB	1077	790	287	6225	202	ER, SP
14N	02W	27	NE	NW	SE		D	B	A		PAGE NO. 1	OIL CAPITOL CORP.	KB	1117	796	321	6004	162	ER, SP
14N	02W	27	SW	NE	SE	NW	B	D	A	C	SNEED #1-27	DSM EXPLORATION INC.	KB	1112	845	267	1110	20	DIL, GR, SP
14N	02W	28	NW	NW	NW		B	B	B		OAKWOOD #1-21	MARJO OIL CO.	KB	1161	710	451	1222	70	DIL, GR, SP, CDL
14N	02W	30	NE	SE			D	A			CLEGERN #1	HARPER-TURNER	DB	1146	775	371	6012	223	ER, SP
14N	02W	31	NW	SE	SW		C	D	B		MARKS 6B-2	PETRO CORP. INC.	KB	1091	788	303	1725	50	IEL, GR
14N	02W	32	NW	SW			C	B			POTTER NOL 1	HARPER-TURNER OIL CO	KB	1063	750	313	5905	205	ER, SP
14N	02W	33	NW	SW			C	B			KUNC NO. 3	HARPER-TURNER OIL CO	DF	1062	755	307	5956	200	ER, SP
14N	02W	36	SE	SE	NW		B	D	D		#1 ROBBERSON	HARPER-TURNER OIL CO	DF	979	650	329	6184	215	ER, SP
14N	03W	01	SW	SE			D	C			FRED #2	HARPER-TURNER	KB	1191	660	531	5998	202	ER, SP
14N	03W	05	SE	NE			A	D			MORGAN NO. 5-1	SINGER-FLEISCHAKER OIL	KB	1060	540	520	872	59	DIL
14N	03W	06	SW	SE			D	C			MC GILL #1	PHILLIPS PETR. CO.	RT*	1100	580	520	648	20	ER, SP
14N	03W	08	SE	SE	SE		D	D	D		HOGAN NO. 1	HARPER-TURNER OIL CO	KB	1096	585	511	6638	208	ER, SP
14N	03W	09	SE	NW	NE		A	B	D		GREY-TRANSWESTERN NO. 1	BRITISH AMERICAN ET AL	DB	1091	660	431	6553	358	ER, SP
14N	03W	10	NE	NE	SW		C	A	A		REMUND NO. 1	BRITISH AMERICAN ET AL	DB	1143	710	433	6565	366	ER, SP
14N	03W	11	NE	NE			A	A			WATTENBERGER #1	HARPER-TURNER	KB	1189	625	564	6028	205	ER, SP
14N	03W	12	NE	NE	SW		C	A	A		SHAFFER #1	HARPER-TURNER	KB	1188	690	498	6204	205	ER, SP
14N	03W	13	NW	NE	SW		C	A	B		CLEAVER NO. 3	HARPER-TURNER	KB	1208	760	448	6062	200	ER, SP
14N	03W	14	NE	NE	SE		D	A	A		J. HALL NO. 2	HARPER-TURNER	KB	1182	683	499	6036	200	ER, SP
14N	03W	15	SE	NE			A	D			SIMMONS NO. 1-15	BOSWELL ENERGY CORP.	KB	1133	656	477	932	35	ER, SP, CDL, GR
14N	03W	16	NE	SW	NW		B	C	A		STATE NO. 2	HARPER-TURNER	KB	1075	640	435	6581	207	ER, SP
14N	03W	16	NE	SW	NW		B	C	A		CITY OF EDMOND NO. 1	HARPER TURNER	KB	1073	620	453	1045	30	DIL, GR, SP
14N	03W	16	NE	NW	NW		B	B	A		STATE NO. 1	HARPER-TURNER	KB	1069	605	464	6529	215	ER, SP
14N	03W	17	NE	NE	SE		D	A	A		BETTY LOU #1	PEDESTAL OIL	KB	1078	604	474	931	20	IEL, GR
14N	03W	17	NE	NE	SE	SW	C	D	A	A	AUDREY #1-17	MARJO OIL CO.	KB	1100	660	440	976	65	DIL, GR, SP
14N	03W	18	NW	NW	SW		C	B	B		BOLING #1	CONTINENTAL OIL CO	DF	1081	695	386	6758	386	ER, SP
14N	03W	19	NE	SE	SW		C	D	A		PRICE #2	MOHAWK DRLG. CO.	KB	1113	685	428	6427	335	ER, SP
14N	03W	19	SE	NW	SW		C	B	D		PRICE #1	MOHAWK DRLG. CO.	KB	1106	650	456	6721	224	ER, SP
14N	03W	20	NE	NW	SW		C	B	A		HIGDON NO. 2	HARPER OIL CO.	KB	1103	633	470	6615	202	ER, SP
14N	03W	24	NW	NW	SW		C	B	B		TEST WELL NO. 28	CITY OF EDMOND	GL	1150	702	448	713	30	IEL, GR
14N	03W	24	NW	NW			B	B			ERICKSON #1	HARPER-TURNER OIL CO	KB	1190	750	440	6089	215	ER, SP
14N	03W	25	NE	SE	NW		B	D	A		UCO #1-25	LANCE RUFFEL OIL & GAS	KB	1211	792	419	1030	54	IEL, SP
14N	03W	28	SW	NW	SW		C	B	C		KELLY NO. 1	CHAMPLIN OIL	KB	1083	730	353	6699	623	ER, SP
14N	03W	29	SE	SW	NW		B	C	D		HOLMES #1	BRITISH AMERICAN OIL	RT	1110	745	365	6572	288	ER, SP
14N	03W	30	NW	NE			A	B			RANDOLPH #3	DENVER PROD. & REF. CO.	DB	1112	750	362	6710	320	ER, SP
14N	03W	31	NE	NE	NE						J.M. YOUNG #9	SUNRAY MID-CONTINENT	KB	1128	790	338	6719	664	IEL, SP
14N	03W	32	SE	NE			A	D			GRIFFIN NO. 2	BLACKWOOD & NICHOLS	KB	1108	805	303	6408	340	ER, SP

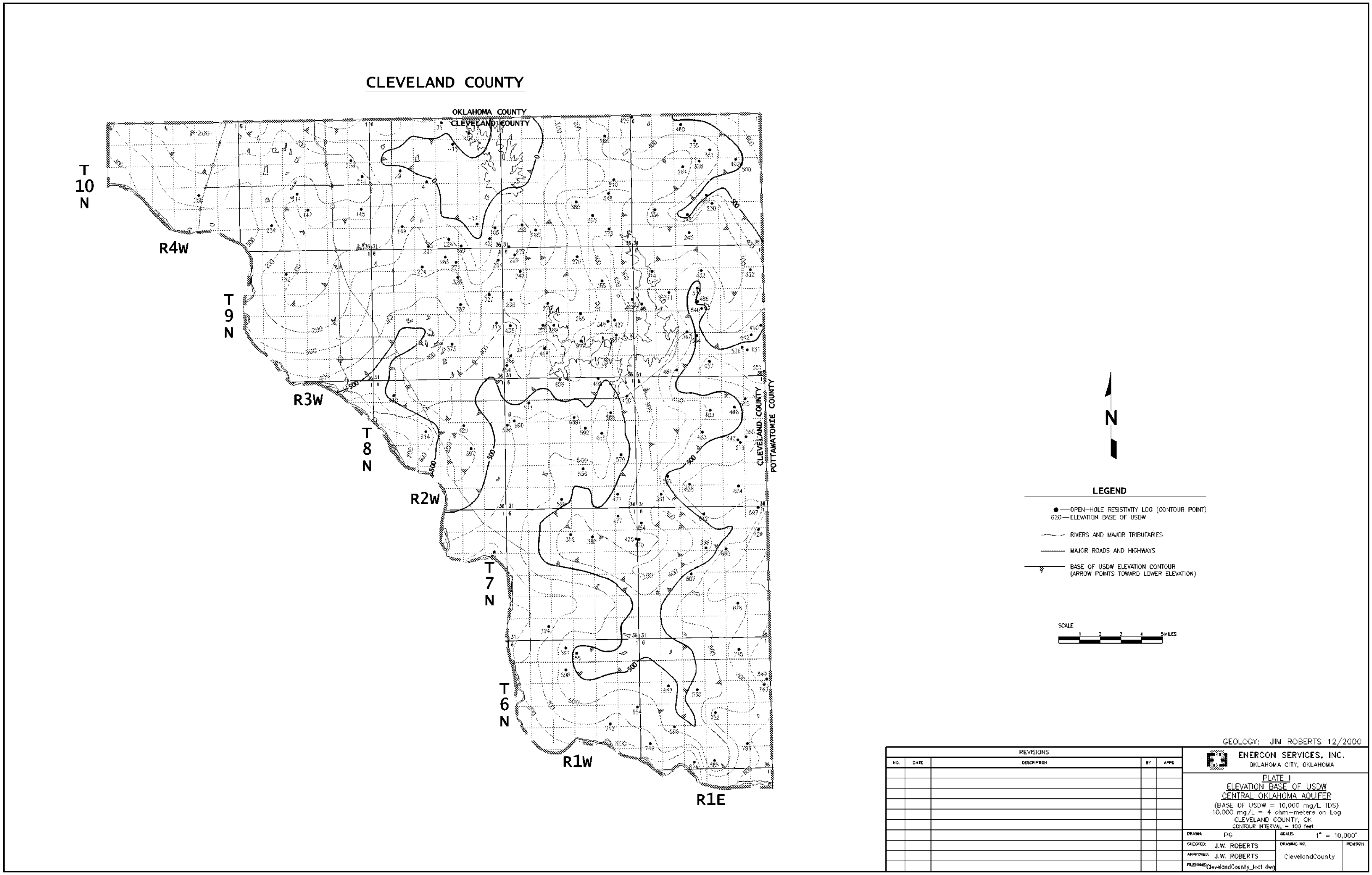
Township	Range	Section	Spot Location of Well: Legal Description				USGS Description				Well Name	Operator	Reference Datum	Datum Elevation (Feet AMSL)	Measured Depth to Base of USDW (Feet)	Elevation Base of USDW (Feet)	Total Depth of Well (Feet)	Depth of Last Log Reading (Feet)	Recorded Log Curves
14N	03W	33	SW	SE			D	C			CONNELLY NO. 1	CABEEN EXPL. CORP.	KB	1113	810	303	6310	341	ER, SP
14N	03W	36	NE	SE	NE						COMMUNITY TRACT #1	STERLING OIL	KB	1130	815	315	6589	213	ER, SP
14N	04W	01	NE	SW			C	A			BERESFORD #1	RENCO & VIERSEN	DB	1122	680	442	6873	430	ER, SP
14N	04W	03	NW	NE			A	B			WHISLER #2	CARTER OIL COMPANY	DB	1013	505	508	6864	332	ER, SP
14N	04W	04	NE	SW			C	A			WHISTLER #4	SOHIO PETROLEUM CO.	DB	1114	670	444	6965	405	ER, SP
14N	04W	05	SE	SE			D	D			MASON #3	CONTINENTAL OIL CO	DB	1133	610	523	6975	411	ER, SP
14N	04W	06	NE	SE			D	A			EDMOND #4	PHILLIPS PETR. COMPANY	DB	1166	680	486	6876	333	ER, SP
14N	04W	07	NW	SE			D	B			CHRISTNER #2	GULF OIL CORP.	DB	1165	688	477	7003	409	ER, SP
14N	04W	08	NW	SE			D	B			ELOISE NO. 1	O'ROURKE-RODKEY-REES	KB	1122	680	442	6627	278	ER, SP
14N	04W	10	SW	SE			D	C			WHISTLER NO. 1	DEER ROCK OIL CORP	DB	1094	600	494	6756	373	ER, SP
14N	04W	11	SW	SW			C	C			WHISLER #1	CITIES SERVICE OIL CO.	DB	1090	630	460	6669	357	ER, SP
14N	04W	12	SE	SW	SE		D	C	C		BOLING NO. 1	CALVERT DRILLING CO	KB	1031	620	411	6606	286	ER, SP
14N	04W	13	SE	NW	NE		A	B	D		SALISBURY #1-A	CALVERT DRILLING CO	KB	1091	648	443	6708	300	ER, SP
14N	04W	14	SE	SE			D	D			R.D. CRAVENS ESTATE NO. 1	J.D. WRATHER, JR.	KB	1030	600	430	6501	323	DIL, SP
14N	04W	15	SE	NW			B	D			GILMORE "A" #1	PHILLIPS PETR. COMPANY	KB	1098	625	473	6356	348	IEL, SP
14N	04W	16	NW	NE			A	B			STATE 16-A #1	ANDERSON-PRICHARD OIL	DB	1118	650	468	6929	416	ER, SP
14N	04W	18	SE	NW			B	D			LYNCH #3	MID-CONTINENT PETR.	DB	1145	715	430	6991	378	ER, SP
14N	04W	19	NE	SW			C	A			PETERSON #1	FOX & FOX	DB	1108	745	363	7012	283	ER, SP
14N	04W	20	SW	SW			C	C			J. BRISCOE #2	STANOLIND OIL & GAS CO.	DB	1106	645	461	6804	470	ER, SP
14N	04W	21	SW	NW			B	C			KING B-2	SOHIO PETROLEUM CO.	DB	1114	770	344	1418	399	ER, SP
14N	04W	22	NW	SE			D	B			LOWRY "A" #1	PEPPERS REFINING CO	KB	1045	570	475	6373	415	ER, SP
14N	04W	23	SE	NW			B	D			SURBECK #23-1	WHITE SHIELD OIL & GAS	KB	1036	570	466	6574	250	IEL, SP
14N	04W	24	NW	NW			B	B			PARKER NO. 1-24	HARDING BROTHERS	KB	1059	550	509	6471	314	DIL, SP
14N	04W	25	NW	SW	SW		C	C	B		SWISHER NO. 1	TRIGG DRILLING CO.	KB	1112	640	472	6490	155	ER, SP
14N	04W	26	NW	SE			D	B			YOUNG NO. 1	TRIGG DRILLING CO.	KB	1083	640	443	6455	165	ER, SP
14N	04W	27	W	NE	SW		C	A			PATTON #1	TRIGG DRILLING CO.	KB	1087	635	452	6498	171	ER, SP
14N	04W	28	NE	SE	SE		D	D	A		DILLON #1-A	N.V. DUNCAN	KB	1069	640	429	6641	396	ER, SP
14N	04W	29	NE	SW			C	A			ARNOLD 1-B	FOX & FOX	DB	1081	705	376	7118	327	ER, SP
14N	04W	30	SW	NE			A	C			BRISCOE #509	SOHIO PETROLEUM CO.	DB	1117	720	397	7010	322	ER, SP
14N	04W	31	SW	NW			B	C			SPIVEY #1	FOX & FOX	DB	1065	620	445	7082	327	ER, SP
14N	04W	32	NW	NW			B	B			YOUNG #2	DICKEY OIL CO	DB	1055	625	430	7065	352	ER, SP
14N	04W	33	NW	SE			D	B			SCHMITZ-MCDOWELL 511	SOHIO PETROLEUM CO.	DB	1086	700	386	6813	405	ER, SP
14N	04W	34	NW	SW			C	B			CARGILL #2	DENVER PROD. & REF. CO.	DB	1100	645	455	6692	265	ER, SP
14N	04W	34	NE	SW			C	A			CARGILL A 4	DENVER PROD. & REF. CO.	DB	1108	640	468	6673	264	ER, SP
14N	04W	35	NE	SE	NW		B	D	A		HOLMES #2	DENVER PROD. & REF. CO.	DB	1051	620	431	6644	276	ER, SP
14N	04W	36	NW	NW	NW		B	B	B		MURPHY NO. 1	TRIGG DRILLING CO.	KB	1109	650	459	6416	161	ER, SP

REFERENCE DATUM = DATUM FROM WHICH THE LOG FOOTAGE WAS MEASURED
* REFERENCE DATUM ELEVATION ESTIMATED FROM USGS TOPOGRAPHIC MAP

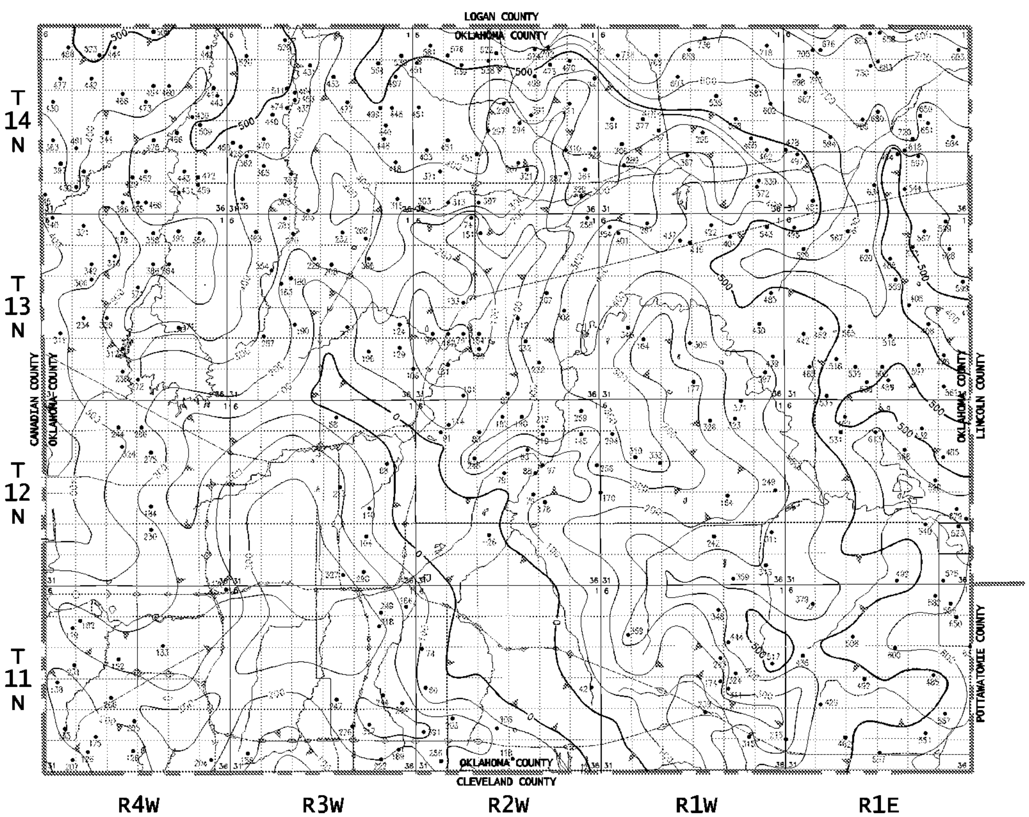
Abbreviations

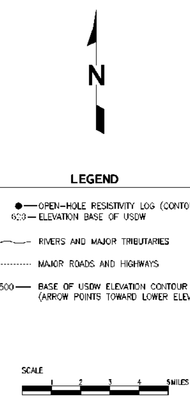
DIL = DUAL INDUCTION LOG
IEL = INDUCTION ELECTRICAL LOG
ER = ELECTRICAL RESISTIVITY LOG
GR = GAMMA RAY LOG
SP = SPONTANEOUS POTENTIAL LOG
CDL = COMPENSATED DENSITY LOG
CNL = COMPENSATED NEUTRON LOG

GL = GROUND LEVEL
DF = DERRICK FLOOR
BH = BRADEN HEAD
RT = ROTARY TABEL
DB = DRIVE BUSHING


CLEVELAND COUNTY
OKLAHOMA COUNTY
CLEVELAND COUNTY
POTTAWATOMIE COUNTY
T 10 N
T 9 N
T 8 N
T 7 N
T 6 N
R4W
R3W
R2W
R1W
R1E
N
LEGEND
OPEN-HOLE RESISTIVITY LOG (CONTOUR POINT)
ELEVATION BASE OF USDW
RIVERS AND MAJOR TRIBUTARIES
MAJOR ROADS AND HIGHWAYS
BASE OF USDW ELEVATION CONTOUR
(ARROW POINTS TOWARD LOWER ELEVATION)
SCALE
5 MILES
GEOLOGY: JIM ROBERTS 12/2000
REVISIONS
NO. DATE DESCRIPTION BY APPD
ENERCON SERVICES, INC.
OKLAHOMA CITY, OKLAHOMA
PLATE I
ELEVATION BASE OF USDW
CENTRAL OKLAHOMA AQUIFER
(BASE OF USDW = 10,000 mg/L TDS)
10,000 mg/L = 4 ohm-meters on Log
CLEVELAND COUNTY, OK
CONTOUR INTERVAL = 100 feet
DRAWN: PG
SCALE: 1" = 10,000'
CHECKED: J.W. ROBERTS
APPROVED: J.W. ROBERTS
DRAWING NO. ClevelandCounty
REVISION
FILENAME: ClevelandCounty_loc1.dwg

OKLAHOMA COUNTY





LEGEND

- ● — OPEN-HOLE RESISTIVITY LOG (CONTOUR POINT)
- 620 — ELEVATION BASE OF USDW
- RIVERS AND MAJOR TRIBUTARIES
- MAJOR ROADS AND HIGHWAYS
- 500 — BASE OF USDW ELEVATION CONTOUR (ARROW POINTS TOWARD LOWER ELEVATION)

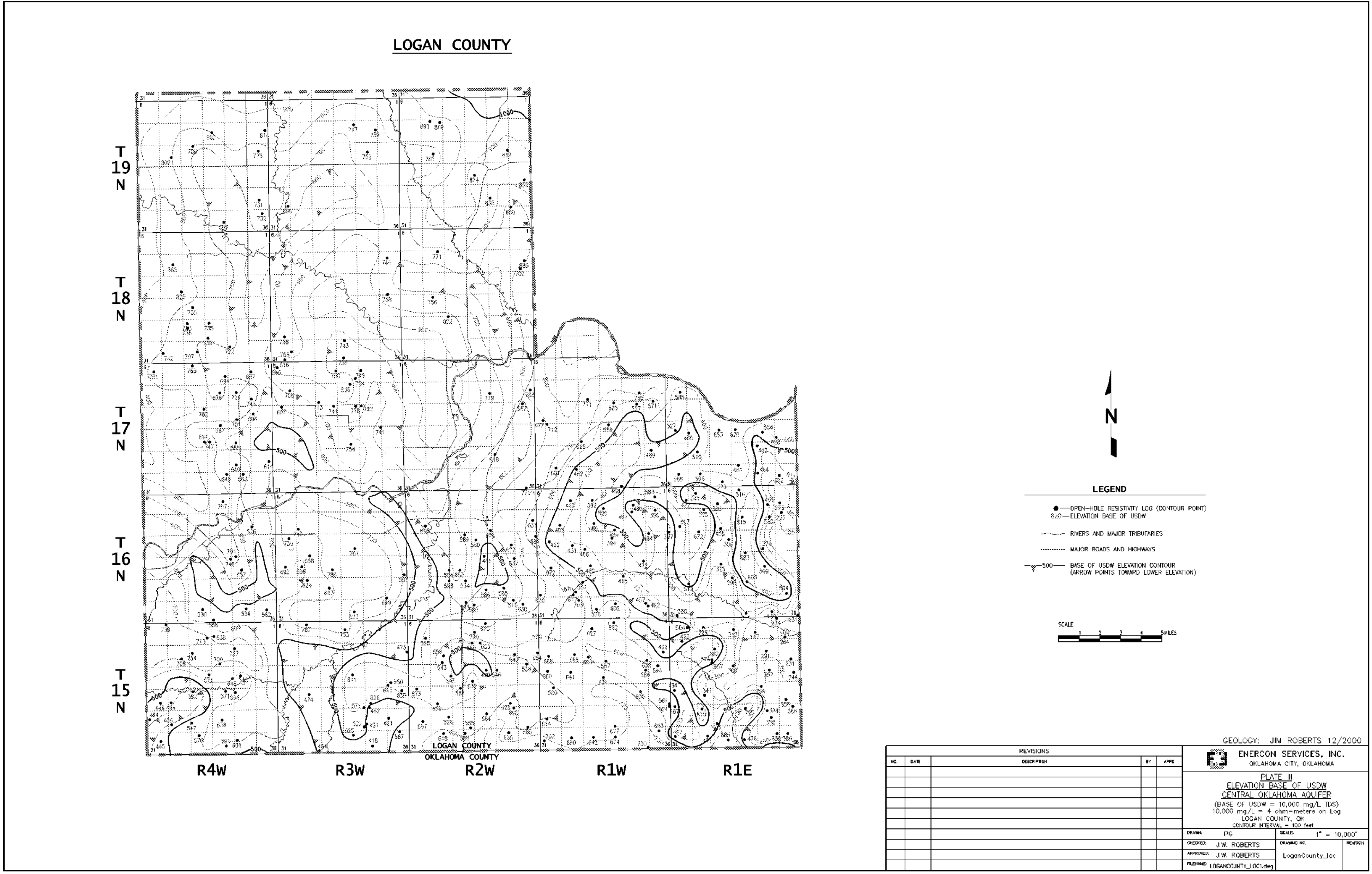
GEOLOGY: JIM ROBERTS 12/2000

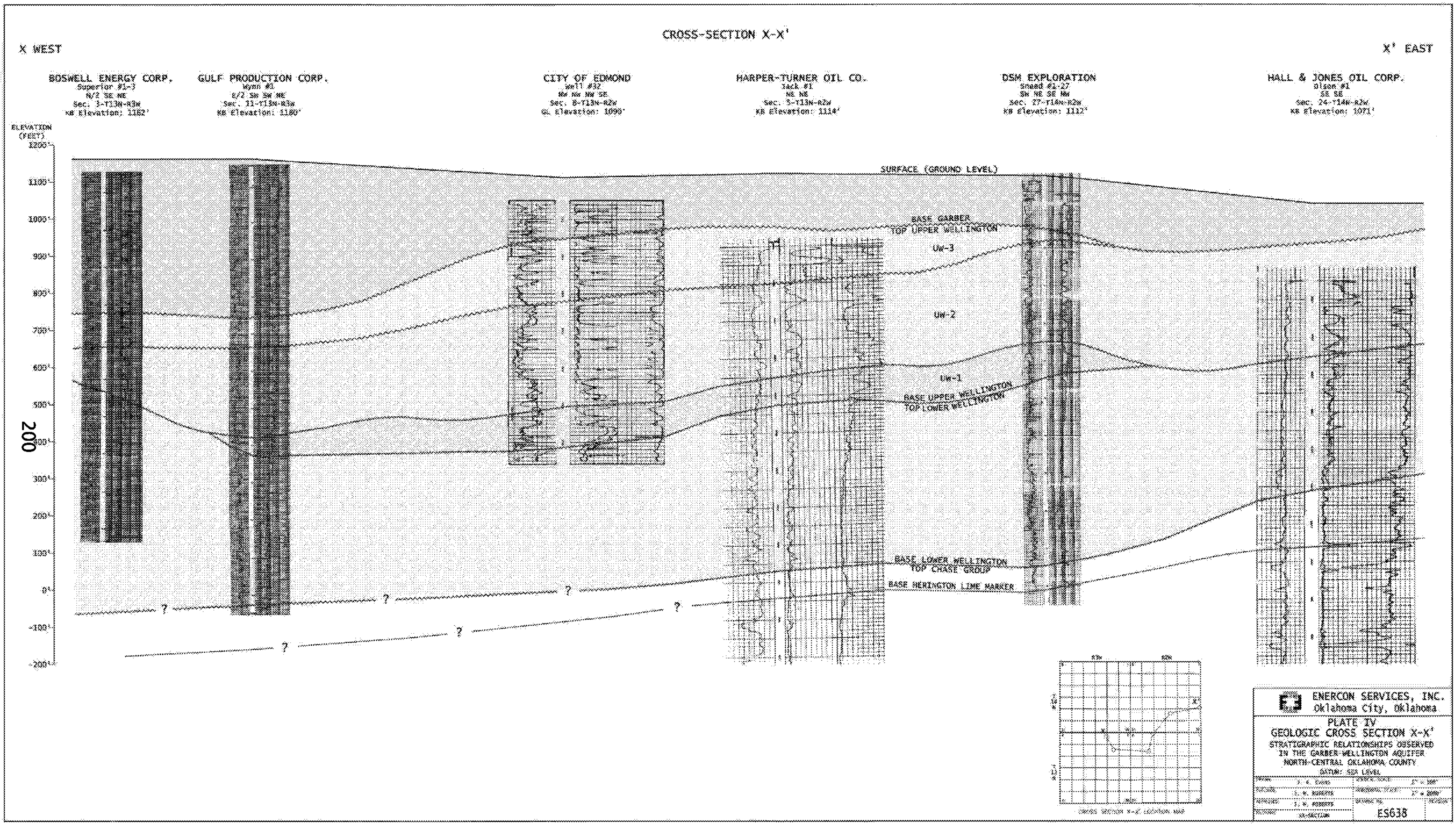
REVISIONS				
NO.	DATE	DESCRIPTION	BY	APPD

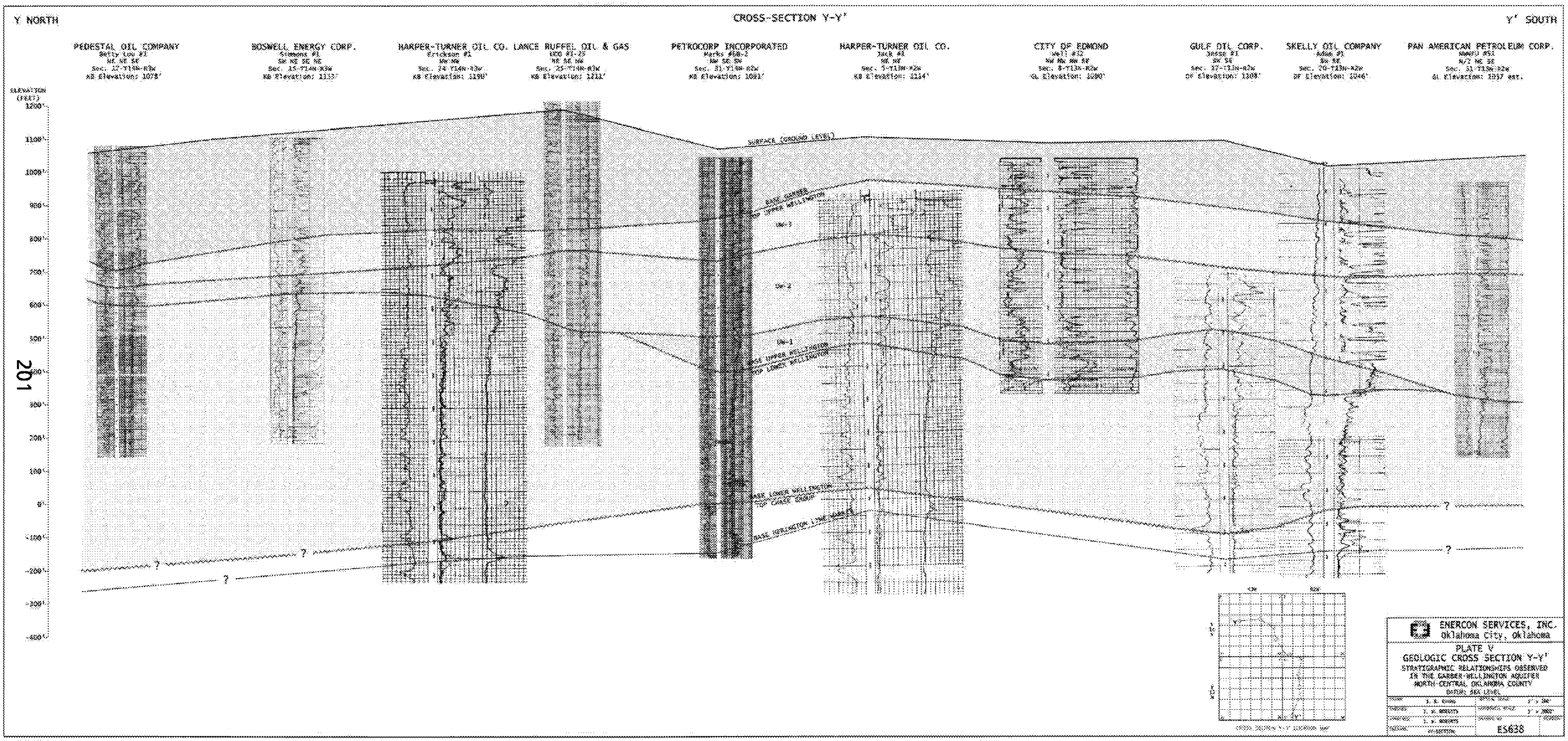
ENERCON SERVICES, INC.
OKLAHOMA CITY, OKLAHOMA

PLATE II
ELEVATION BASE OF USDW
CENTRAL OKLAHOMA AQUIFER
(BASE OF USDW = 10,000 mg/L TDS)
10,000 mg/L = 4 ohm-meters on Log
OKLAHOMA COUNTY, OK
CONTOUR INTERVAL = 100 feet

DRAWN: PG		SCALE: 1" = 10,000'	
CHECKED: J.W. ROBERTS		DRAWING NO. OKLOCLhyd	REVISION
APPROVED: J.W. ROBERTS			
FILENAME: OKLOCLhyd.dwg			


LOGAN COUNTY
T 19 N
T 18 N
T 17 N
T 16 N
T 15 N
R4W
R3W
R2W
R1W
R1E
LOGAN COUNTY
OKLAHOMA COUNTY
N
LEGEND
OPEN-HOLE RESISTIVITY LOG (CONTOUR POINT)
ELEVATION BASE OF USDW
RIVERS AND MAJOR TRIBUTARIES
MAJOR ROADS AND HIGHWAYS
BASE OF USDW ELEVATION CONTOUR (ARROW POINTS TOWARD LOWER ELEVATION)
SCALE
5 MILES
GEOLOGY: JIM ROBERTS 12/2000
REVISIONS
NO.
DATE
DESCRIPTION
BY
APPD
ENERCON SERVICES, INC.
OKLAHOMA CITY, OKLAHOMA
PLATE III
ELEVATION BASE OF USDW
CENTRAL OKLAHOMA AQUIFER
(BASE OF USDW = 10,000 mg/L TDS)
10,000 mg/L = 4 ohm-meters on Log
LOGAN COUNTY, OK
CONTOUR INTERVAL = 100 feet
DRAWN: PG
SCALE: 1" = 10,000'
CHECKED: J.W. ROBERTS
APPROVED: J.W. ROBERTS
DRAWING NO. LoganCounty_loc
REVISION
FILENAME: LOGANCOUNTY_LOC1.dwg


CROSS-SECTION X-X'
X WEST
X' EAST
BOSWELL ENERGY CORP.
Superior #1-3
N/2 SE NE
Sec. 3-T13N-R3W
KB Elevation: 1182'
GULF PRODUCTION CORP.
Wynn #1
E/2 SW SW NE
Sec. 11-T13N-R3W
KB Elevation: 1180'
CITY OF EDMOND
Well #32
NW NW NW SE
Sec. 8-T13N-R2W
GL Elevation: 1090'
HARPER-TURNER OIL CO.
Jack #1
NE NE
Sec. 5-T13N-R2W
KB Elevation: 1114'
DSM EXPLORATION
Snead #1-27
SW NE SE NW
Sec. 27-T14N-R2W
KB Elevation: 1112'
HALL & JONES OIL CORP.
Olson #1
SE SE
Sec. 24-T14N-R2W
KB Elevation: 1071'
ELEVATION (FEET)
1200'
1100'
1000'
900'
800'
700'
600'
500'
400'
300'
200'
100'
0'
-100'
-200'
SURFACE (GROUND LEVEL)
BASE GARBER
TOP UPPER WELLINGTON
UW-3
UW-2
UW-1
BASE UPPER WELLINGTON
TOP LOWER WELLINGTON
BASE LOWER WELLINGTON
TOP CHASE GROUP
BASE HERINGTON LIME MARKER
?
R3W
R2W
X'
ENERCON SERVICES, INC.
Oklahoma City, Oklahoma
PLATE IV
GEOLOGIC CROSS SECTION X-X'
STRATIGRAPHIC RELATIONSHIPS OBSERVED
IN THE GARBER-WELLINGTON AQUIFER
NORTH-CENTRAL OKLAHOMA COUNTY
DATUM: SEA LEVEL
ES638


Y NORTH
CROSS-SECTION Y-Y'
Y' SOUTH
PEDESTAL OIL COMPANY
Betty Lou #1
NE NE SE
Sec. 17-T14N-R3W
KB Elevation: 1078'
BOSWELL ENERGY CORP.
Simmons #1
SW NE SE NE
Sec. 15-T14N-R3W
KB Elevation: 1133'
HARPER-TURNER OIL CO.
Erickson #1
NW NW
Sec. 24-T14N-R3W
KB Elevation: 1198'
LANCE RUFFEL OIL & GAS
Sec. 25-T14N-R3W
KB Elevation: 1211'
PETROCORP INCORPORATED
Marks #68-2
NW SE SW
Sec. 31-T14N-R2W
KB Elevation: 1081'
HARPER-TURNER OIL CO.
Jack #1
NE NE
Sec. 5-T13N-R2W
KB Elevation: 1114'
CITY OF EDMOND
Well #32
NW NW NW SE
Sec. 8-T13N-R2W
GL Elevation: 1090'
GULF OIL CORP.
Jesse #1
SW SE
Sec. 17-T13N-R2W
DF Elevation: 1108'
SKELLY OIL COMPANY
Adam #1
SW SE
Sec. 20-T13N-R2W
DF Elevation: 1046'
PAN AMERICAN PETROLEUM CORP.
N/2 NE SE
Sec. 31-T13N-R2W
GL Elevation: 1057 est.
ELEVATION (FEET)
1200'
1100'
1000'
900'
800'
700'
600'
500'
400'
300'
200'
100'
0'
-100'
-200'
-300'
-400'
SURFACE (GROUND LEVEL)
BASE GARBER
TOP UPPER WELLINGTON
UW-3
UW-2
UW-1
BASE UPPER WELLINGTON
TOP LOWER WELLINGTON
BASE LOWER WELLINGTON
TOP CHASE GROUP
BASE WELLINGTON LIME
?
ENERCON SERVICES, INC.
Oklahoma City, Oklahoma
PLATE V
GEOLOGIC CROSS SECTION Y-Y'
STRATIGRAPHIC RELATIONSHIPS OBSERVED
IN THE GARBER-WELLINGTON AQUIFER
NORTH-CENTRAL OKLAHOMA COUNTY
DATUM: SEA LEVEL
ES838

San Juan Basin Ground Water Modeling Study:

Ground Water – Surface Water Interactions

Between Fruitland Coalbed Methane

Development and Rivers

October, 2001

Prepared by:
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Matthew Janowiak, Bureau of Land Management – Durango Field Office

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Appendices

1.0 Executive Summary

The Ground Water Protection Research Foundation (GWPRF) has sponsored this project to model the surface water and ground water interactions associated with coal bed methane (CBM) development in the northern San Juan Basin of Colorado (Figures 1 and 2). Ground water production from coalbed aquifers is required for recovering CBM. By pumping water, the pressure in the CBM reservoir is reduced and methane then desorbs from the coal and flows through the natural cleat system to the pumping wells. This project was designed to quantify the maximum surface water depletion that may occur as a result of CBM development in the Fruitland Formation.

Previous work had shown that, prior to CBM development, approximately 194 acre-feet per year (ac-ft/yr) of water was discharging to the Animas, Florida, Pine (Los Piños), and Piedra Rivers from the Fruitland Formation subcrop. Regional reservoir modeling work also indicated that the artesian pressures in the Fruitland Formation were being reduced on a regional scale as a result of dewatering associated with CBM production, and that with future CBM development, a reversal of the hydraulic relationship between the rivers and the Fruitland aquifer might occur. However, the regional models were not adequate for predicting the maximum surface water depletion. Analytical solutions were insufficient for characterizing two-phase flow in the multi-layer aquifers, and more comprehensive numerical solutions were required to adequately define a reasonable maximum depletion term.

This study developed multi-layer models at the Animas, Florida, and Pine Rivers. The Piedra River area was not modeled due to lack of geologic and reservoir information. Each model area encompassed a river crossing, adjacent outcrop areas, and several square miles of active CBM producing regions within the basin (Figure 3). Coalbeds were modeled by grouping coals in up to 5 “packages” or layers. The intervening strata were also grouped and assigned to layers. The Pictured Cliffs Sandstone was modeled as a distinct layer, and finally the Lewis and Kirtland Shales were modeled as impermeable boundaries at the bottom and top of the model.

For each model area, MODFLOW was used to define the equilibrium conditions of ground water flow, recharge, discharge, and related potentiometric heads. These results were used as starting conditions in the reservoir model. The reservoir model was then used to simulate the effects of CBM development on the river/ground water interactions.

Supporting fieldwork associated with model development included:

1. The development of geologic cross-sections at each river cut along the outcrop,
2. Geologic mapping of the Fruitland and Pictured Cliffs Sandstone near the Piedra River, with stratigraphic sections and mapping of surface water features (springs and wetlands) and existing methane seeps.
3. An assessment of fracture density in the upper Pictured Cliffs Sandstone,
4. Stable isotope sampling from various CBM wells, and
5. An assessment of the hydraulic properties of non-coal or clastic sedimentary deposits of the Fruitland Formation.

This study shows that CBM development will deplete a maximum of 140 ac-ft/yr of surface flows from the Animas, Pine, and Florida rivers by the year 2050. A further depletion of 15 to 60 ac-ft/yr can be expected for the Piedra, given the similar hydrogeologic characteristics and assuming the future level of CBM development in the area near the Piedra River will be the same as that experienced in La Plata County. As of 2001, approximately 65 ac-ft/yr are being depleted from surface waters. Depletions will continue to increase as long as CBM production occurs, although most of the impacts will occur within the next 30 to 50 years.

2.0 Introduction

Coalbed methane (CBM) is rapidly becoming an important source of natural gas in the U.S.A. The San Juan Basin of New Mexico and Colorado was one of the first regional CBM developments in the world (Figures 1 and 2). The Fruitland Formation of the San Juan Basin contains approximately 50 trillion cubic feet of methane, with approximately 50% recoverable.

The state of knowledge relating to CBM has evolved over the past decade, and now it is understood that in the San Juan Basin, the Fruitland Formation is a regional aquifer with marginal to poor water quality (1,000 to >10,000 ppm Total Dissolved Solids) and low yields. Recharge occurs along the outcrop on the basin rim, and discharge occurs where the rivers cross the outcrop at lower elevations. The coalbeds subcrop into alluvium in the river valleys.

Artesian pressures in the Fruitland Formation are maintained by water recharging into the aquifer at high elevations around the northern basin rim. Because the structural basin is also a topographic basin, pressures remain artesian over most of the northern portion of the basin, as much as 20 miles basinward from the northern outcrops.

Development of CBM requires a reduction in the water pressure to allow methane to desorb and flow to a well. In effect, CBM recovery requires reducing the pressure in the coal beds to a point where gas will dominate the 2-phase flow system. Complete development of the Fruitland CBM resource induces a situation where the CBM wells are pumping considerably more water than can be recharged. As a result, CBM development intercepts ground water that would normally discharge to rivers, and may cause some of the surface water flows in the rivers to drain into the Fruitland Formation.

This study was performed to quantify the total potential depletions of surface waters that could be induced by CBM development in the northern San Juan Basin. It is intended to provide policy-makers with a reasonable maximum depletion amount.

2.1 3M Summary

In 1999, the Colorado Oil and Gas Conservation Commission (COGCC), Bureau of Land Management (BLM), and Southern Ute Indian Tribe (SUIT) sponsored a study to predict future impacts associated with basin-wide CBM development in Colorado. The primary thrust of the 3M (Mapping, Modeling, and Monitoring) study was to develop an understanding of the relationship between methane seepage at the outcrop and CBM development within the basin. The 3M study showed that with continued CBM production, methane seepage at the outcrop will increase 4 to 20 times over seepage rates seen today (Questa, 2000).

The 3M study did not address potential surface water depletions. However, the study calculated that approximately 194 ac-ft/yr of ground water was discharging from the Fruitland Formation to local rivers prior to any development. The 3M study also showed that there was localized hydraulic interconnection between the Fruitland Formation and the underlying Pictured Cliffs Sandstone.

Concern about maximum surface water depletions was raised when it became evident that the depletions might exceed the 194 ac-ft/yr by an unknown but potentially large amount.

The regional models were limited in their utility for fine-scale surface water/ground water interactions. The investigators recognized that finer-scale models were needed to assess maximum depletions of surface water. Furthermore, the investigative team recognized that CBM development is just beginning in other Western US coal basins, and that the technical approach to defining surface water depletions would be applicable to many other basins.

2.2 Project Scope

The San Juan Basin Ground water Modeling Study is made up of the following tasks:

- *Geologic sections at river crossings.* These sections were developed to provide a detailed assessment of alluvial fill aquifers overlying the Fruitland and Pictured Cliffs Sandstone subcrops in the river valleys.
- *Fracture density in Pictured Cliffs Sandstone.* These data were collected to better constrain the bulk permeability of the upper Pictured Cliffs Sandstone. If high fracture density was observed, then adjustments to the model parameters could be made to better simulate actual transport within the Pictured Cliffs.
- *Stable Isotope Sampling.* Extensive stable isotope sampling was performed as part of the 3M study. However, few samples were collected near the outcrop during the 3M study. Twenty-four

additional samples were collected as part of this project to refine the interpretations based on stable isotope data. Stable isotope (deuterium and oxygen-18) data may be used to make inferences on paleoclimatic conditions when the water fell as precipitation on the outcrop. From there, a rough estimate of ground water age dates may be made.

- *Estimates of Fruitland non-coal hydraulic parameters*. Because non-coal strata in the Fruitland would be modeled, estimates of hydraulic parameters for the Fruitland mudstone and sandstone beds were needed.
- *Hydrologic Model*. MODFLOW models were developed for three river crossings at the Florida, Pine and Animas rivers to simulate pre-CBM development conditions. These models provided input into the reservoir model.
- *Reservoir Model*. COALGAS™ and EXODUS™ models were developed using the same model grids as the MODFLOW models. The COALGAS™ and EXODUS™ models simulate 2-phase flow, so the model accounts for relative permeability changes as methane is desorbed from the coal. These models were used to predict reasonable maximum depletions of surface water.
- *Assessment of Depletion Potential at Piedra River*. The Fruitland Formation and Pictured Cliffs Sandstone were mapped along the Piedra River. Mapping focused on identifying surface water features, existing methane seeps, and preparing detailed stratigraphic sections of the Fruitland Formation. This information was used to determine if there were any key differences at the Piedra River that might lead greater or lesser surface water/ground water interconnection.

3.0 Methods

The methods used to conduct each task are described in the following sections. Only brief descriptions of methods are provided, with references to detailed methodologies made where applicable.

3.1 *Field Work and Geologic Characterization*

The following sections describe methods used when conducting field work and compiling data.

3.1.1 River/Subcrop Cross-Sections

Geologic sections were prepared where the Pine, Florida, and Animas Rivers cross the Fruitland and Pictured Cliffs Sandstone subcrops. These sections were prepared by compiling logs from water wells, geotechnical borings, and field visits. Water well logs were collected from the BLM's files. Twelve water well logs were available in the Pine River area, but none were available at the Florida and Animas River crossings. Monitoring well logs were also available at the Pine River crossing. The water well logs are very general, with descriptions of the soil and bedrock encountered during drilling (Appendix A). Monitoring well logs are more detailed.

Geotechnical logs were received from the Colorado Department of Transportation at the Animas River crossing. Most of the geotechnical work was done in support of bridge and road construction, and those logs are fairly detailed in their description of the encountered lithologies.

3.1.2 Pictured Cliffs Sandstone - Fracture Density

Fracture density was only characterized in the massive upper Pictured Cliffs Sandstone. The lower Pictured Cliffs Sandstone is interbedded siltstone and sandstone with bed thicknesses ranging from a couple centimeters to 0.75 meters. The fine-grained nature of the lower Pictured Cliffs Sandstone makes it less likely to be a major transport pathway for fluids. The upper Pictured Cliffs Sandstone is massively bedded, and over 40 feet thick in many areas. Although the primary permeability of the massive sandstone is fairly low, there is evidence that fractures are a secondary permeability feature capable of increasing the bulk permeability of the rock.

Fracture density was measured by laying a 100-ft long measuring tape across an exposed surface of the Pictured Cliffs Sandstone, near the contact with the Fruitland Formation. The tape was laid parallel to strike.

The number of fractures intercepted by the tape were tabulated in 5-ft increments and recorded. Characteristics of the fractures were noted, including iron stains, open or closed, etc.

The tape was then extended another 100 feet along strike and the process repeated.

3.1.3 Fruitland Shale/Sandstone – Hydraulic Parameters in Non-coal Strata

Non-coal strata within the Fruitland Formation were visually inspected at outcrop. These inspections were focused on evidence of fluid flow through these clastic strata, and gross field descriptions of non-coal strata. Photographs were taken along a representative Fruitland section to document the findings.

Visual clues for fluid transport included stained fractures, fracture density, thickness and geometry of sandstone beds, and the relationship between the sandstone and coal within the Fruitland.

Because the Fruitland shale strata have not been hydraulically tested, either by production tests or other methods, a default value of 1 microdarcy was used for shale hydraulic conductivity (Freeze and Cherry, 1979, Domenico and Schwartz, 1990, and Todd, 1980).

3.1.4 Stable Isotope Sampling

Water samples were collected from 21 producing coal bed methane wells. Samples were collected at the gas-water separator, which is part of a closed system that precludes fractionation of the water or contamination from atmospheric sources. Two water samples were collected from domestic water wells tapped into the Fruitland Formation on the outcrop, and one water sample was collected from a piezometer on the Fruitland outcrop. Domestic well samples were collected at a tap or by lowering a bailer down the well; the piezometer was sampled by bailer.

Samples were collected in 1 liter plastic bottles, packed in a box and shipped via FedEx to the laboratory for isotopic analysis.

All water samples were submitted to Isotech Labs in Champaign, Illinois for stable isotopic analysis (oxygen and hydrogen stable isotopes).

3.2 Modeling

Three model codes were used in this study. All codes used the same 3D model grids to model the detailed geology of the Fruitland Formation coal beds and other formations. Up to 11 layers were needed to effectively model the ground water/surface water interactions. Model layers were defined by numerous detailed geophysical logs from Fruitland CBM wells and from the work done by the Colorado Geological Survey (Wray, et al., 2000).

MODFLOW was used to define the conditions prior to CBM development in the Fruitland-Pictured Cliffs system and aquifer recharge-discharge relationships. MODFLOW is a public domain 3D ground water flow model developed by the USGS (McDonald and Harbaugh, 1988). VISUAL MODFLOW® is the interface and data processing package that was used to input and manage data and view model output.

For CBM reservoir modeling, commercially available two-phase, three-dimensional CBM reservoir simulation models were used. COALGAS™ (Schlumberger-Holditch Reservoir Technologies) was used to set up the initial model scoping runs. Because of scheduling difficulties, a second simulation program, EXODUS™ (T.T. and Associates, Inc.) was used to make the final history match and predictive runs. These programs perform very similarly, and simulate simultaneous gas and water flow with relative permeability effects associated with 2-phase flow as well as the unconventional characteristics of gas desorption. These models were set up to utilize the same model configuration as MODFLOW, including cell size, porosity, permeability, and layer geometry.

3.2.1 Model Domains (Hydrologic and Reservoir Model)

Model domains were selected to provide sufficient distance from the model boundaries and the rivers. The goal was to reduce boundary effects near the river cuts and nearby CBM wells. Figure 3 shows the model domains for the three river cuts.

3.2.2 Layer Definition (Hydrologic and Reservoir Model)

Model layers were defined based on the work by the Colorado Geological Survey (Wray, et al., 2000). The Fruitland Formation contains three to five distinct "packages" of coalbeds that can be correlated across nearly the entire northern San Juan Basin. Coalbed thicknesses were aggregated within each package. These packages defined each coal layer within the model domain. The thickness of each coal layer was developed from well logs within and adjacent to the model domain, and then the thicknesses were contoured to define layer thickness across the model domain. Coal was picked off the well logs based primarily on the density logs, with coal defined as material having less than 2.00 grams per cubic centimeter (gm/cm^3) density.

The intervening strata or non-coal materials were also summed up over the coal package. These non-coal strata were used to define the thickness of intervening layers between the coal layers. Again, these aggregate thicknesses were defined by well log analysis and the values were contoured across the entire model domain.

Finally, the upper Pictured Cliffs Sandstone was modeled as a separate layer. Only the uppermost massive sandstone was used to define this layer because the lower Pictured Cliffs Sandstone tends to become increasingly fine-grained and ultimately grades into the Lewis Shale. Fluid transport through the predominantly fine-grained lower Pictured Cliffs Sandstone is dominated by the lower permeability fine-grained material.

The Kirtland Shale, overlying the Fruitland Formation, was not assigned a layer with thickness and material properties. The Lewis Shale, underlying the Pictured Cliffs Sandstone, was also not assigned as a layer within the model. Both were represented as impermeable boundaries.

3.2.3 Grid Spacing (Hydrologic and Reservoir Model)

Model grids were 1/6 mile by 1/6 mile or 880 feet by 880 feet across each model domain. The same grid spacing was used for the MODFLOW, COALGAS™ and EXODUS™ models.

Grid dimensions for each model domain are:

1. Animas River - 50 x 43
2. Florida River - 35 x 21
3. Pine River - 30 x 24

Grid sizes were checked to ensure that the models could account for most of the surface water features within the model domain, particularly along the outcrop areas.

3.2.4 Hydrologic Model – Hydraulic Parameters, Boundary Conditions, Calibration

Permeability, storativity, and porosity for coal beds were well defined from previous work (Applied Hydrology, 2000). These parameters were not varied significantly for this study.

Permeability

There were no data for defining the hydraulic parameters for the non-coal strata and for the upper Pictured Cliffs. Permeabilities of the coal beds were determined in the previous 3M studies. The non-coal clastic materials interbedded with the coalbeds have permeabilities many times lower than the coals. Starting horizontal (k_h) permeability values for the non-coal strata were 0.01 times the coal permeability. Vertical permeability (k_z) was estimated to be one to two orders of magnitude less than k_h (Walton, 1988, Domenico and Schwartz, 1990).

Porosity

The porosity distribution determined from history matching production data for the COALGAS™ model was used in the hydrologic models.

Storativity

A constant specific storage of 1×10^{-5} /ft was assumed for all layers. For cells in the outcrop area where flow may be unconfined, a specific yield equal to the porosity was used.

Boundary Conditions

Within the basin, boundary conditions for all layers were constant head boundaries. This allowed the models to accept water flow through every model layer into and out of the model domains. For all layers, each boundary cell was assigned a head value based on the results from the 3M regional model (Applied Hydrology Associates, 2000).

Along the outcrop, boundary conditions were established to simulate deep recharge. An injection well was placed in each coal layer and the total amount of recharge estimated for each cell was apportioned as injection into the coal layers. Rivers and ditches crossing the outcrop were drain cells, allowing water to discharge or recharge, as needed.

Calibration

Because the hydrologic models were tightly constrained by boundary conditions, the calibration process was straightforward. Good matches were observed between potentiometric heads predicted by the previous regional-scale model and those predicted by the detailed multi-layer models. Surface water discharge rates were a similar order of magnitude, but varied to some extent from those predicted by the regional model. This is discussed in Section 3.2.1.4.

3.2.5 Reservoir Model – Hydraulic Parameters, Boundary Conditions, Coal Properties (Gas Content), Calibration

The same fundamental parameters were used for the CBM reservoir model as were used for the hydrologic model. Differences between the models included:

Initial Pressure

The initial pressures used for the CBM reservoir model were the final steady-state pressures or heads determined from the hydrologic model, which was run without any consideration of CBM development.

Relative Permeability Curves

Relative permeability curves were initially selected using the 3M results, and were adjusted as needed to obtain a general match to historic gas and water production levels.

Permeability and Porosity

The 3M results were used as a basis for other reservoir properties such as porosity and permeability. Because the multi-layer model had slightly different total coal thickness than the 3M model, the permeability was adjusted to obtain the same total transmissivity in the coal in both models.

Aquifer Connection

Aquifer connection was utilized in those areas where the 3M model indicated connection to the Pictured Cliffs Sandstone or sources of water other than the coal. The Pictured Cliffs Sandstone was included as a blanket layer 50 feet thick with 0.1 md horizontal permeability throughout most of the model areas. The intervening strata were assumed to have a permeability of 0.00001 md throughout most of the area. Where additional connection was indicated, the permeability of the Pictured Cliffs Sandstone was increased to a permeability level comparable to the coal permeability, and the confining layer permeability was increased to 1 to 10 md as needed in those areas.

Gas Content

Gas contents were computed using the Langmuir isotherm, with isotherm parameters of 545 scf/ton for the Langmuir volume and 315 psia for the Langmuir pressure, in accordance with the 3M model results.

Boundary Conditions

The locations of recharge and discharge points in the reservoir model were carried over from the original 3M CBM model. Generally, a recharge node was included every third block along the outcrop to reduce the number of recharge nodes needed. In the Pine River and Florida River models, small amounts of water were injected around the boundary of the model prior to production to better match the initial head distribution determined with MODFLOW. The reservoir models were allowed to equilibrate for 500 years prior to the start of production.

Calibration

Calibration targets were defined as reasonably matching the main producing phase in an area, with special emphasis on the large water producers. Detailed rematching was beyond the scope of this effort.

Final runs for each model area are discussed in the following section.

4.0 Results and Discussion

This section discusses the results from each task as they relate to the ground water – surface interactions along the Fruitland Formation and Pictured Cliffs Sandstone.

4.1 Field Work

Field work consisted of development of cross-sections at each river crossing, fracture density characterization in the upper Pictured Cliffs, visual investigation of fluid transport in non-coal strata within the Fruitland Formation, and stable isotope sampling.

4.1.1 Cross-Sections

The cross sections illustrate a near-direct connection between the rivers and the Fruitland/Pictured Cliffs subcrops. At the Animas River, there is an extremely thin mantling of very coarse-grained alluvium over the formations, indicating very strong hydraulic interconnection between the surface water and the aquifer system (Figures 4 through 8). Alluvial material is predominantly boulders, cobbles and gravel, with minor amounts of sand. It is essentially free of finer-grained sediments.

At the Pine River, the river valley is relatively broad as it crosses the formations, approximately 1 mile wide (Figures 9 and 10). The water well drillers' logs and other logs, along with surficial deposits, all indicate the alluvial fill aquifer is relatively thin, and has very high permeability.

The Florida River crossing had less information available, but field work indicated that the river is still downcutting where it crosses the formations (Figures 11 and 12). This downcutting shows up in relatively steep river gradients at the subcrops. The alluvial fill at the Florida River is very coarse grained. It is comprised of boulders, cobbles, and gravel with minor amounts of sand. Again, the degree of interconnection between the river and aquifer system is very high. The river valley is relatively narrow, limiting the aquifer area exposed to the alluvial fill aquifer.

At the Florida River, there are two unlined irrigation ditches that cross the outcrop. These large ditches have gravel and sand bottoms, and also are in direct hydraulic communication with the outcrop.

In summary, the Fruitland Formation and Pictured Cliffs Sandstone are in direct hydraulic communication with the river/alluvial fill aquifer system. This relationship justifies the use of open drain cells where the rivers and ditches cross the outcrop.

4.1.2 Pictured Cliffs Sandstone – Fracture Density

Fracture density in the upper Pictured Cliffs is variable (Appendix C). However, stained fractures, or those showing evidence of ground water transport prior to being exposed at the surface, had a very low occurrence. Stained fracture density was 1 per 100 feet in two transects, and 6 per 100 feet in another transect. These fractures were all less than 0.1 inch wide.

When these data are coupled with the numerous well logs and permeability measurements within the Pictured Cliffs Sandstone, it becomes evident that the dominant permeability is the primary permeability, and that secondary permeability resulting from fractures is highly localized. Therefore, there was no justification for modeling Pictured Cliffs Sandstone permeability to reflect secondary permeability features.

4.1.3 Fruitland Shale/Sandstone – Evidence of Hydraulic Parameters

Results of the field investigation of the Fruitland Formation exposed section at the Ridges Basin access road indicate no high permeability fluid flow pathways within the Fruitland non-coal strata. Non-coal strata consist of carbonaceous shale, mudstone, and lenses of friable, fine-grained sandstone. The sandstone lenses are bounded by mudstone at the upper and lower contacts. Sandstone bodies appear to be quite limited in their lateral continuity. Given the limited extent of the sandstone bodies, and the overall preponderance of fine-grained sediments in the section, it does not appear that significant fluid flow can be transported by the non-coal strata within the Fruitland.

4.1.4 Stable Isotopes

The 24 samples analyzed as part of this study were added to the 3M dataset, giving a total of 118 analyzed samples. All but four of the 118 samples analyzed had isotopic values on or near the global meteoric water line (Figure 14). This means that virtually all the produced water is recharge water, and does not display any evidence for water-rock interactions. The stable isotope data were plotted and contoured for δO^{18} and δD (Figures 15 and 16). These maps show a very strong trend of isotopically light water nearer the outcrop with a fairly rapid increase in isotopic weights basinward from the outcrop.

An initial attempt was made to infer dates of the water by using the paleotemperature transfer functions developed by Phillips, et al., (1986) in their study of the Ojo Alamo Sandstone in Northern New Mexico. However, the paleotemperature functions of Phillips, et al., 1986, do not appear valid for the isotope values measured in the Fruitland ground water (Phillips, personal communication). Ground water age dates cannot be inferred with any accuracy from the stable isotope data.

However, the isotope contour plots (Figures 15 and 16) show a regional flowpath from the outcrop along the axis of the Pine River. This is inferred from the deeper incursion of isotopically light (younger) water much deeper into the basin along this flowpath. It appears that there is a fairly high degree of separation between the near outcrop lighter water and the deep basin water in the region west of the Pine River Valley. This is displayed by the very steep gradients between lighter and heavier water.

The isotope contour plots (Figures 15 and 16) also support the concept that the majority of ground water flow in the Fruitland/Pictured Cliffs system in the San Juan Basin occurs in fairly direct, shallow paths from the recharge areas at higher elevations, to the major river cuts at the Pine, Florida, and Animas Rivers, and to a southwesterly discharge point at Soda Springs.

4.1.5 Piedra River Field Investigation

The Piedra River investigation results are in Appendix B. The field mapping along the Fruitland and Pictured Cliffs Sandstone outcrops shows that this area is similar to the other three rivers crossing the outcrop. There is a similar structure, stratigraphy, and topographic relationship between the Piedra River and the outcrop area. Surface water features (springs and wetlands) were identified that are similar to those in the Texas Creek and Edgemont Ranch springs areas (Appendix B). Some minor methane surface seeps were noted along the outcrop.

The isotope contour plots (Figures 15 and 16) suggest there is limited hydraulic connection between the Piedra River and the main CBM producing area of the San Juan Basin. If there were significant connection, there would be younger water flowing through to the Piedra River. Because of the limited degree of connection, existing CBM production is not anticipated to have a significant impact on ground water discharge into the Piedra River.

4.2 Modeling

This section describes the results of the hydrologic baseline modeling and predictive 2-phase flow modeling. Figure 17 is a schematic representation of the 3-dimensional model prepared for the Pine River area.

4.2.1 Baseline Hydrologic Model

Models of steady-state hydrologic systems are very sensitive to recharge. As part of the 3M Study, recharge rates for the Fruitland outcrop were evaluated through a combination of:

- Data from USGS-maintained precipitation monitoring station data for the entire San Juan Basin
- Analysis of the variability of precipitation with altitude, latitude, and longitude over the entire San Juan Basin
- National Atmospheric Deposition Program data for the entire San Juan Basin
- Chloride mass balance analysis using water chemistry data from 152 shallow ground water wells in La Plata County, to determine recharge as a percentage of precipitation for the Colorado Portion of the San Juan Basin

- Comparison with recharge estimates performed for other arid Western and Colorado Plateau basin studies
- Use of chloride as a recharge water tracer in conjunction with a single-layer ground water flow model to indicate ground water migration paths
- Use of stable isotope paleotemperature indicators in conjunction with a single-layer ground water flow model as a check on ground water migration rates
- Parameter optimization performed as part of the detailed ground water modeling program, to fine-tune the estimated recharge for individual portions of the outcrop within specified limits

The combination of these approaches provided a detailed and well-supported picture of recharge rates for the entire Fruitland outcrop. The appropriate rate was used for each of the three multi-layer detailed models presented in this report. A summary of the model runs is in Appendix D.

Pine River– Boundary conditions were set in the Pine River Area as constant head boundaries away from the outcrop, and recharge cells along the outcrop (Figures 18 and 19). The ground water flow patterns show there is primary pathway subparallel to the outcrop (Figure 20). This is due to the higher permeabilities of the shallower coalbeds. In the Pine River model, a recharge value of 0.10 in/yr was used. This resulted in 4,763 ft^3/d (39.5 ac-ft/yr) discharge from the coal packages to the Pine River, 2,320 ft^3/d (19.4 ac-ft/yr) discharge to Bear Creek, and 296 ft^3/d (2.5 ac-ft/yr) discharge to Pine River Ditch (Figure 21).

Florida River– Boundary conditions for all layers are shown in Figures 22 and 23. The potentiometric contours show a fairly strong discharge zone in the Florida River area (Figure 24). In the Florida River model, a recharge value of 0.11 in/yr was used. This resulted in 410 ft^3/d (3.4 ac-ft/yr) discharge from the coal packages to the Florida River and 536 ft^3/d (4.5 ac-ft/yr) discharge to Horse Gulch (Figure 25). Total discharge at the Florida River valley is 7.9 ac-ft/yr, which is significantly less than the 30 ac-ft/yr simulated in the single-layer 3M regional model (Applied Hydrology, 2000). The discrepancy between the single-layer 3M results and the multi-layer model of this study is discussed below.

Animas River – Boundary conditions for the Animas River model are shown in Figures 26 and 27. Similar to the other regions, the ground water flow is concentrated very near the outcrop areas (Figure 28). In the Animas River model, a recharge value of 0.085 in/yr was used. This resulted in 5,012 ft^3/d (42.0 ac-ft/yr) discharge from the coal packages to the Animas River and 2,631 ft^3/d (22.0 ac-ft/yr) discharge to Basin Creek (Figure 29).

The simulated pre-development Fruitland discharges at the three river crossings totaled 15,968 ft^3/d (134 ac-ft/yr), compared with predicted discharges for these three crossings in earlier single-layer modeling of 152 ac-ft/yr. This 12% reduction is a fairly minor difference, but it is considered to be a more realistic estimate of pre-development Fruitland discharge. The difference reflects the fact that the earlier single-layer model approximated the Fruitland coals by aggregating the coal packages together as one unit. This "net coal" unit was located at a mid-point elevation calculated as the thickness-weighted mid-point of all of the coal packages. The base of this artificial unit was therefore higher than the actual base of the lowermost coal package, and the top of the net coal unit was lower than the top of the uppermost coal package. In the more realistic representation provided by the current multi-layer models, the coal packages are set at the correct elevations. As a result, the uppermost coal packages are less likely to be fully saturated with ground water. Consequently, they contribute less to the overall transmissivity of the coal units as a whole, and contribute proportionally less to the overall ground water flow. This is particularly the case in the vicinity of the outcrop where a large part of the natural ground water flow occurs.

4.2.2 CBM Reservoir Model

The CBM reservoir model computes volumes of discharge to the rivers prior to CBM development that are slightly different than the hydrologic model, because of differences in the model inputs and the model methodologies. The results are sufficiently similar using the different models, however, to establish that the models perform in a similar fashion prior to development. All models were run with existing wells as the current state, and assumed that all open spacing units in the area would have a producing well by 2003 (Figure 30). Future production from currently undrilled spacing units was thereby accelerated in this model run, which should lead to a more conservative approach for modeling a reasonable maximum depletion value.

Florida River – Initial reservoir pressure in the Florida River is depicted in Figure 31. Reservoir pressures at year 2050 are shown in Figure 32. These figures show an overall decline in reservoir pressures resulting from historical and future water and gas production. Compared to other regions within the basin, pressure depletion in the Florida River area is much lower. An excellent match was obtained between simulated and historical production in the Florida River area (Figure 33). Using this characterization, current potential stream depletion as a result of CBM activities in this area was estimated at 2.9 ac-ft/yr from existing wells. If all approved infill wells could be drilled, completed, and hooked up for production by Jan. 1, 2003, the stream depletion in the model would increase to 4.5 ac-ft/yr by 2010. A reasonable maximum depletion rate of about 13 ac-ft/yr will occur in 2050, by which time reservoir pressures should near the minimum reservoir pressures for economic production (Figure 34).

The reservoir model had a simulated pre-development discharge rate of 17.5 ac-ft/yr at the Florida River and irrigation ditches. This is more that twice the discharge modeled in the MODFLOW baseline run, which simulated a discharge rate of 7.9 ac-ft/yr. This fairly large difference between the EXODUS model and the MODFLOW model is due to the different ways the boundary conditions are handled by each code. The MODFLOW model allows for flow into and out of the model domain with constant head boundary cells, whereas the EXODUS model requires that injection wells be placed along the boundaries to simulate inflow into the model domain.

The EXODUS model discharge rate of 17.5 ac-ft/yr falls between the 3M single layer results of 30 ac-ft/yr and the multi-layer MODFLOW results of 7.9 ac-ft/yr. Because the EXODUS model had a good match with initial pressures, and the production matches were also very good, the 17.5 ac-ft/yr discharge at the Florida River is an acceptable estimate of pre-development conditions.

Pine River – Initial pressures in the Pine River area are shown in Figure 35. A comparison with current pressures and simulated pressures at year 2050 show a much more marked decline in reservoir pressure compared to the Florida River area (Figures 36 and 37). A good match was achieved between simulated and historical gas production in the Pine River area (see Figure 38), although the model overestimates actual water production. Current depletions are on the order of 25 ac-ft/yr. The projected depletion rate in 2010 is 55 ac-ft/yr. Depletions from the Pine River asymptotically approach 61 ac-ft/yr (Figure 39). It appears that CBM production will deplete the discharge from the Fruitland and Pictured Cliffs Sandstone. However, the Pine River is not altered to a losing stream under the reasonable maximum depletion scenario.

The model results are considered to form a bounding case, wherein actual water production and stream depletion should be less than computed values. The model indicates that producing wells will capture the majority of recharge that formerly discharged to the river. However, it also indicates the formation of a high gas saturation would reduce the effective permeability to water near the outcrop to such low levels that some ground water flow would still discharge into the Pine River valley even after as much as 35 years of production (Figure 40).

Animas River - Initial pressures in the Animas River area are shown in Figure 41. A comparison with current pressures and simulated pressures at year 2050 show a much more marked decline in reservoir pressure compared to the Florida River area (Figures 35 and 42). A good match was achieved between simulated and historical gas production in the Animas River area (see Figure 43), although the model overestimates actual water production. Current depletions are on the order of 35 ac-ft/yr. The projected depletion rate in 2010 is 55 ac-ft/yr. Depletions from the Animas River asymptotically approach 66 ac-ft/yr (Figure 44). It appears that CBM production will deplete the discharge from the Fruitland and Pictured Cliffs Sandstone. However, the Animas River is not altered to a losing stream under the reasonable maximum depletion scenario.

As with the Pine River model, the overprediction of water production is due, in part, to an estimated leakance term over the model areas that may be too high. Higher leakance rates between the Pictured Cliffs Sandstone and the Fruitland Formation will permit a high simulated water production rate from the CBM wells. The overall effect on surface water depletions is minimal, as discussed in Section 4.4.2.

The model results are considered to form a bounding case, wherein actual water production and stream depletion should be less than computed values. The model indicates the majority of recharge that historically discharged to the river will be captured by producing wells. It further indicates the formation of a high gas saturation would reduce the effective permeability to water near the outcrop to such low levels that some ground water flow would still discharge into the Animas River valley even after as much as 35 years of production (Figure 44).

4.3 Depletions from Surface Water due to CBM Development

Maximum surface water flow depletion is comprised of intercepted ground water component where CBM wells effectively cut off the ground water that would have normally discharged to the rivers. The baseline hydrologic models indicate that the Fruitland and Pictured Cliffs Sandstone contributed approximately 145 ac-ft/yr to the Animas, Florida, and Pine Rivers. These contributions were part of the base flow component for the rivers (Table 1). For comparison, combined base flows for these rivers (based on data provided by COGCC) are 188,231 ac-ft/yr. Overall, the predicted base flow depletion is approximately 0.07% of combined base flow. The comparison for each of the streams is shown in the following table:

TABLE 1 Comparison of Fruitland/Pictured Cliffs Discharge with Measured Base Flows

Stream	Measurement location	Period	Measured Base Flow (ac-ft/yr)	Predicted Baseline Fruitland Discharge (ac-ft/yr)	Predicted Maximum Depletion from CBM (ac-ft/yr)
Pine River	Pine River near Bayfield	1975-1986	36,198	61	61
Florida River	Florida River near Durango	1950-1960	7,240	17.5	13
Animas River	Animas River at Durango	1987-1998	144,793	66	66

4.4 Uncertainties in Analyses

The computer simulations have underlying assumptions that have an uncertainty associated with them. Among other things, some uncertainty stems from untested geologic materials, some originates from the investigators' judgement as what constitutes a good match between the simulations at the data, and there are uncertainties tied to what may or may not occur in the future in terms of the development scenarios.

4.4.1 Match Errors

Although an excellent match was achieved in the Florida River area, the simulated water production rates in the Pine River and Animas River areas were nearly twice as large as the actual reported rates from the wells. These errors are attributed to the presence of additional flow restrictions that are probably related to the presence or absence of fracturing and fracture connection to the Pictured Cliffs in some areas, possible faulting in some areas, and/or stratigraphic discontinuities in some of the coal beds. The original 3M model, which the current models derive from, was formulated on the assumption of general continuity in the system. The results of this multi-layer run suggest that there are probably more barriers or flow restrictions in this area that restrict or prevent some of the water movement computed in the model. For bounding purposes, the existing model formulation should provide an upper limit on possible water production and therefore an upper limit on potential stream depletion.

4.4.2 Non-coal Strata Properties

The properties of the Pictured Cliffs Sandstone and the intervals between the coals have not been well-characterized in previous studies. Accordingly, commonly used ground water estimates have been applied to these intervals. The low water production rates in many of the wells was used to estimate a maximum vertical permeability of the confining strata as 0.0001 md. This is based on the observed water rates less than 10 bwpd in many wells, a total of 6 to 10 interfaces between the coals and the intervening layers, the nominal historical well spacing of 320 acres per well, and a hydraulic gradient of 1000 psi or more per 100 ft after the pressure in the coal drops. Additional model runs were made to evaluate the effect of vertical permeability of this level (Figures 45, 46, and 47). It was found that different values of confining layer permeability had virtually no effect on computed discharge rates into the streams. This probably relates to the fact that water production in the model is constrained by the observed water production rates. Flow in the model is mostly lateral rather than vertical, even at higher leakance levels, so the maximum stream depletion is primarily influenced by the level of water withdrawals.

4.4.3 Fracture Flow in the Pictured Cliffs Sandstone.

The presence of water flow through fractures in the Pictured Cliffs Sandstone in some areas has been inferred from geologic and hydrologic reasoning. In the Pine River area, for example, the lowermost coal in the Dulin D-1 well lies almost directly on the Pictured Cliffs, and water isolation experiments conducted by the operator demonstrated that the majority of that water entered the well in the basal coal. However, the degree of fracturing in the Pictured Cliffs is extremely localized, inasmuch as none of the other wells offsetting the Dulin D-1 experienced a similar connection.

4.4.4 Effects of Future Development

Additional CBM wells will probably be drilled in the future to recover a greater percentage of this large gas resource. Bounding limit simulation runs were prepared in the three areas to show the effect of potential future development. For modeling purposes, it was assumed that all permitted infill wells in these areas would be drilled, completed, and placed on production at the beginning of 2003. This unrealistically rapid development schedule should provide an upper limit to the potential effects of infill drilling on stream depletion. It was found that infill wells would have a negligible effect on stream depletion in the Pine River area (Figure 39) and Animas River area, but that infill drilling would increase predicted stream depletion by about 7.5 ac-ft/yr in the Florida River area (Figure 34).

5.0 Conclusions

The models in this study were purposely developed to err on the conservative side, to provide a reasonable upper limit for potential surface water depletions. Models were constrained by the available data, but when estimates were required or there was a range of potential values for a parameter, the investigators chose the value that might give a higher depletion value.

Maximum surface water depletions associated with full-field CBM development (at 160-acre well spacing) are predicted to be 140 ac-ft/yr for the Animas, Pine, and Florida Rivers. These depletions are broken down as follows: 66 ac-ft/yr in the Animas River, 13 ac-ft/yr in the Florida River, and 61 ac-ft/yr in the Pine River. Maximum depletions at the Pine and Animas Rivers will begin around year 2030.

Given that the Piedra River has a similar hydrogeologic character as the three rivers that were modeled, an estimated 15 to 60 ac-ft/yr of maximum surface water depletion can be expected (Appendix B).

Therefore, a reasonable maximum value for surface water depletions in northern San Juan Basin rivers is 155 to 200 ac-ft/yr. These numbers are significantly lower than previous estimates of potential stream depletion made by the BLM using analytical techniques.

The depletion values fall well within the 3,000 ac-ft/yr that are allowed for all Federal projects within the San Juan River Basin. Maximum depletion values are 5% to 8% of the total allowable depletions, and will not impact management of the San Juan River hydrology. BLM and the USFS will study mitigation actions for these depletions, given the long-term nature of the surface water losses due to CBM production. The mitigation study will be performed in support the ongoing Northern San Juan Basin Environmental Impact Statement.

6.0 Modeling Approach Applicability to Western US CBM Basins

There are many similarities between the areas modeled for this project and other Western US coal bed methane basins, including the Powder River, Uinta, Piceance, and Green River basins. These are all in semi-arid to arid environments with low precipitation, low and/or sporadic recharge, snowmelt recharge, and generally multiple-layered low permeability coal beds, with predominantly fracture-controlled permeability and porosity. They all have coal-bed methane potential and are at varying stages of development, with the San Juan Basin currently being at the most advanced stage. As water production is an intrinsic component of coal bed methane development, the comparable basins share similar potential environmental consequences, including depletion of adjacent ground water and surface water, and the physical and chemical effects of disposal of produced ground water.

7.0 Acknowledgements

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FIGURES

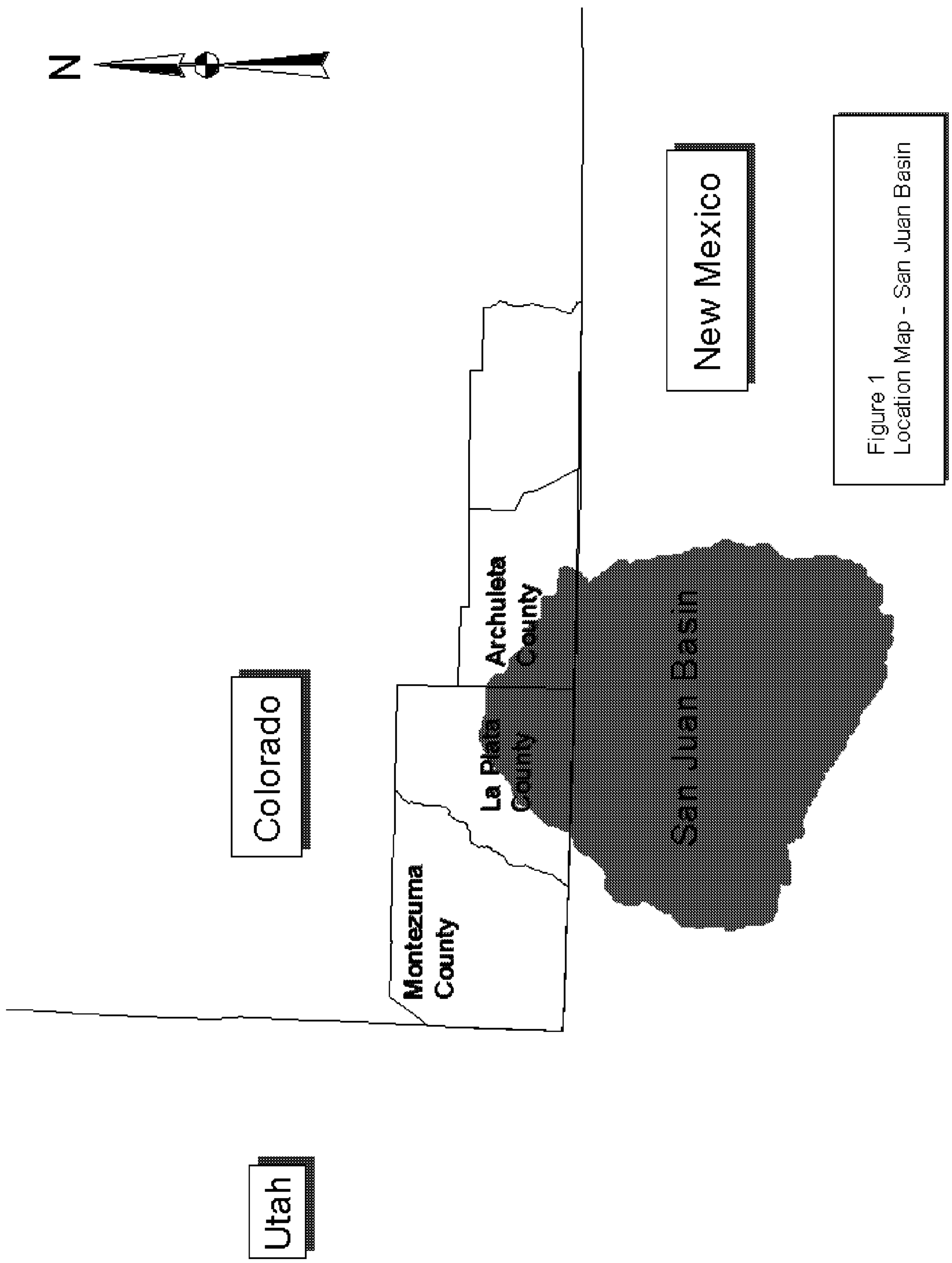


Figure 1
Location Map - San Juan Basin

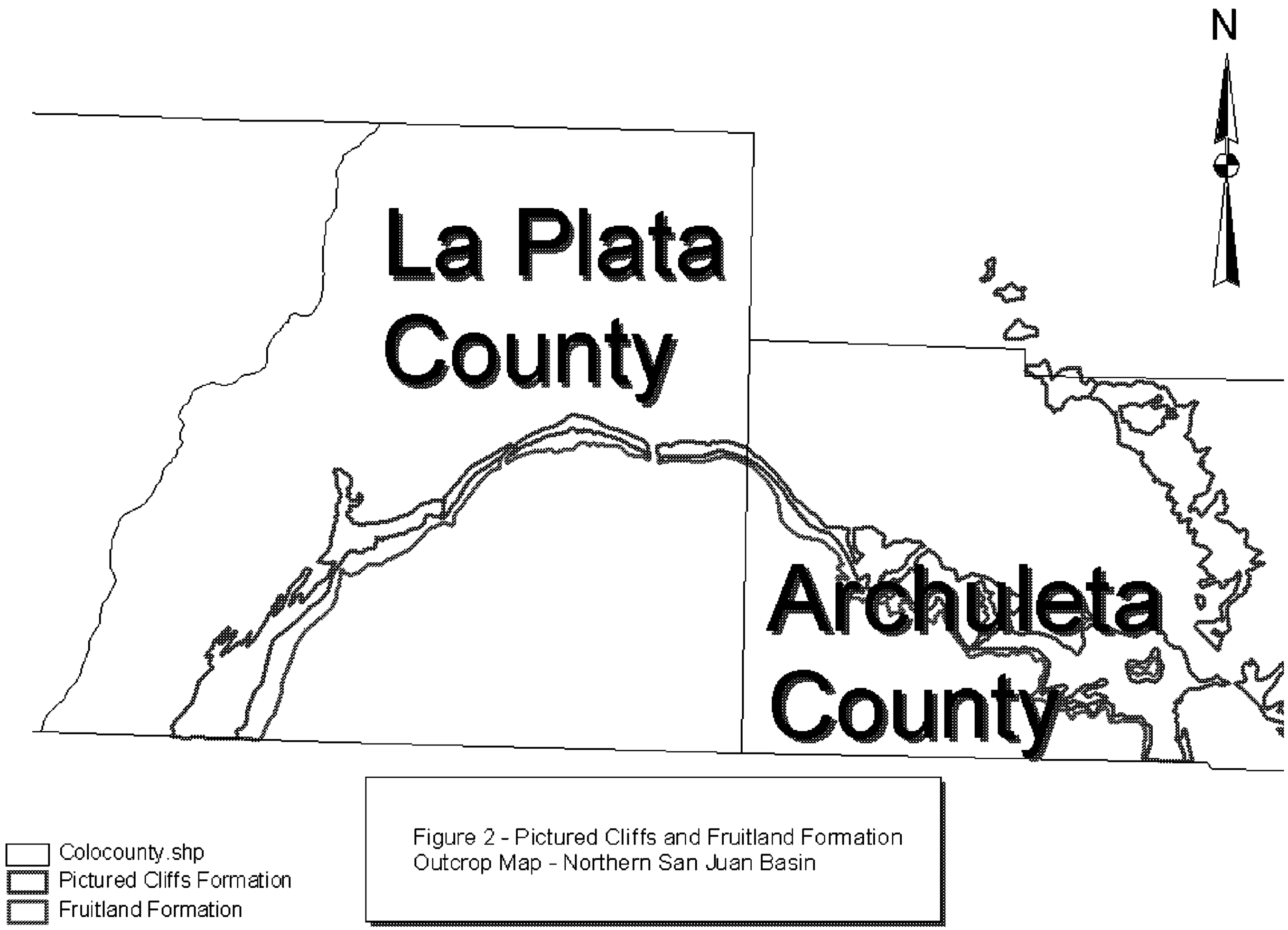


Figure 2 - Pictured Cliffs and Fruitland Formation Outcrop Map - Northern San Juan Basin

Figure 3 – Location of Modeled Areas

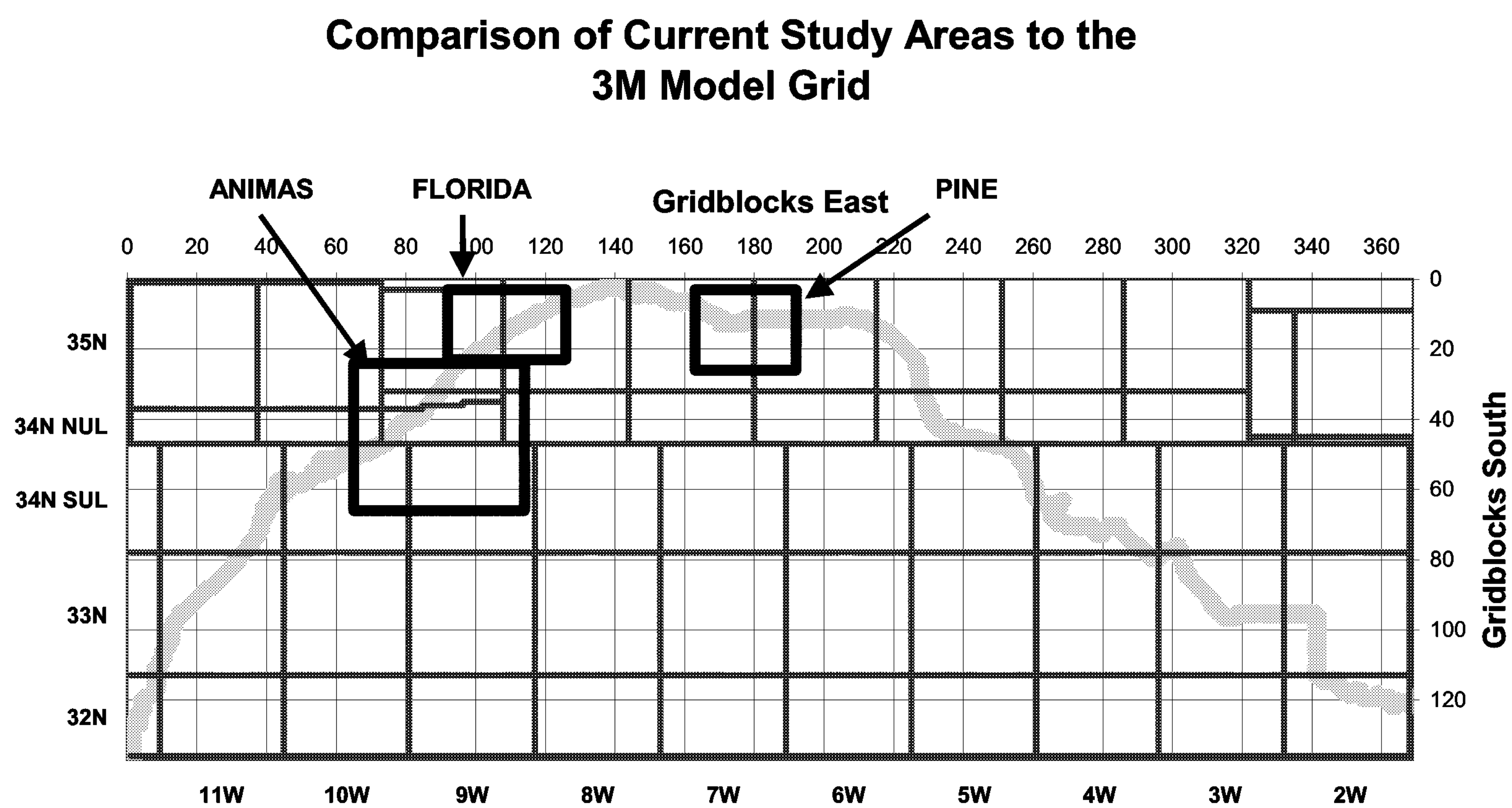


Figure 3a – Model Grids Used in This Study Compared to 3M Model Grids

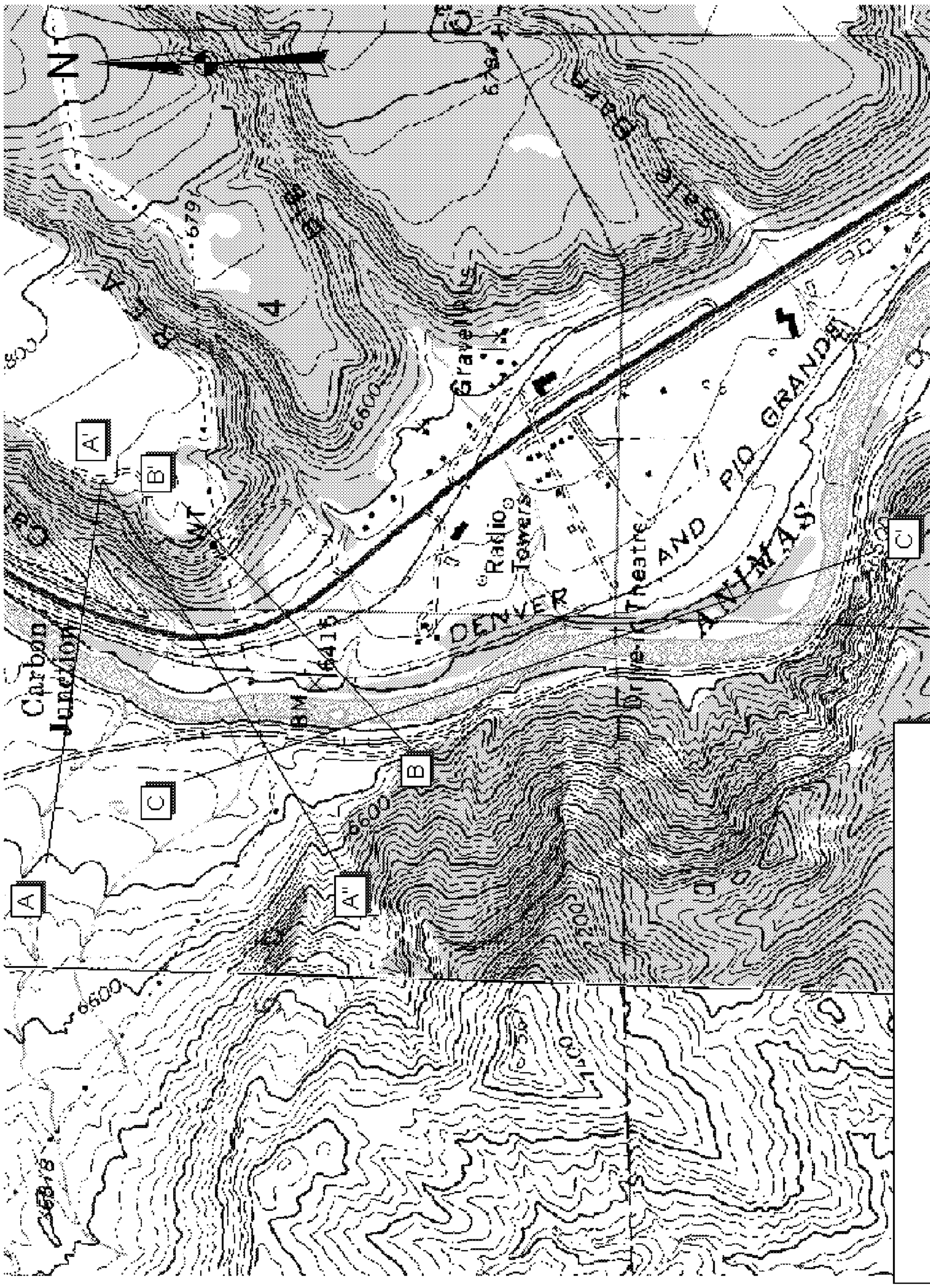


Figure 4 - Cross Section Lines at Animas River

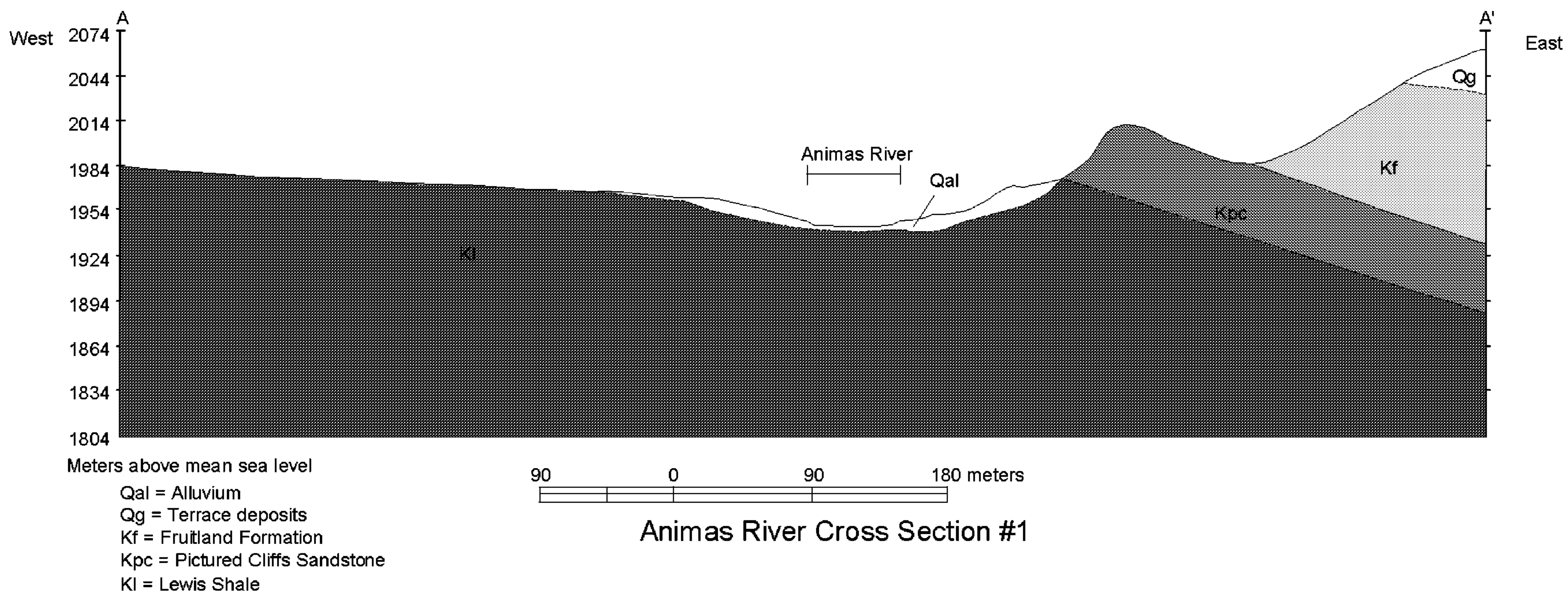


Figure 5 – Animas River Cross Section A to A'

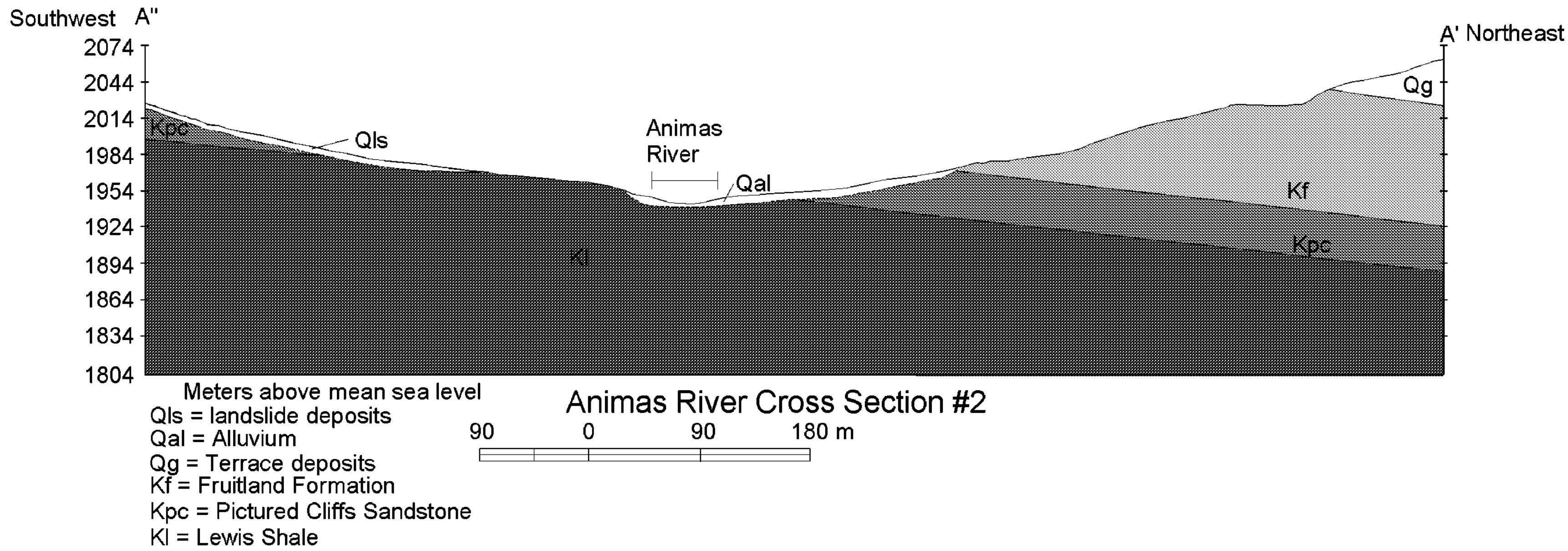


Figure 6 – Animas River Cross Section A" to A'

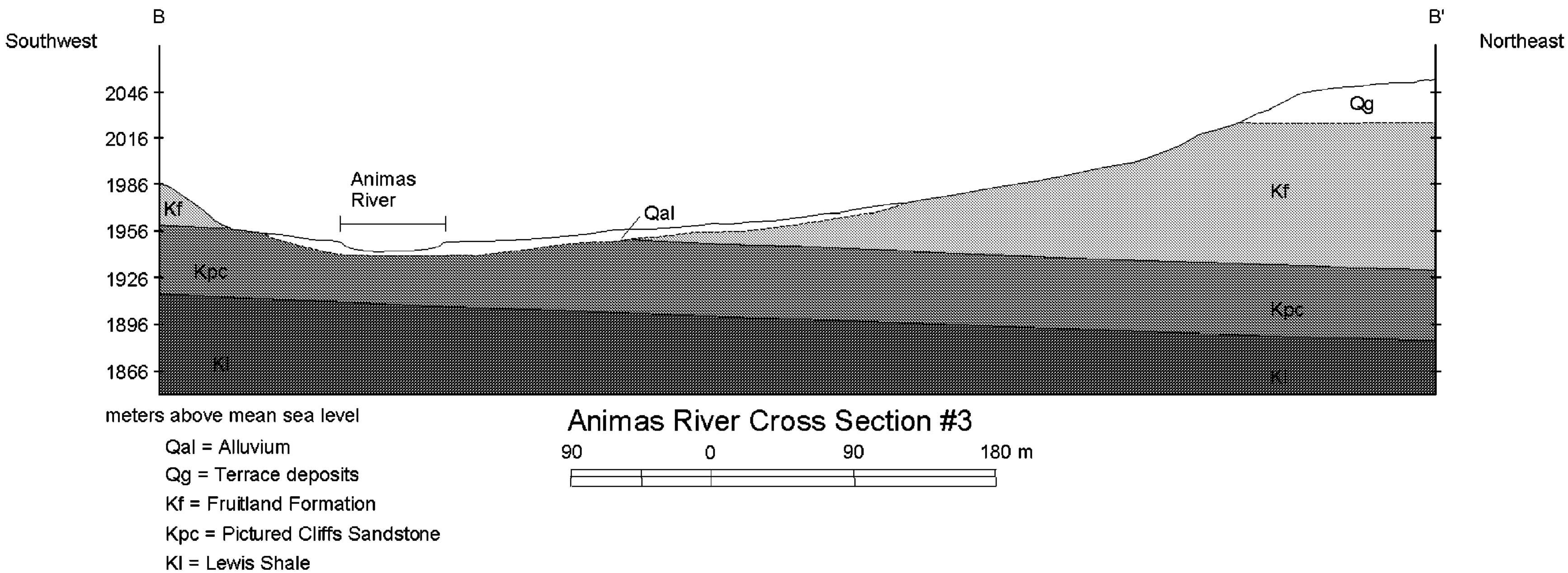
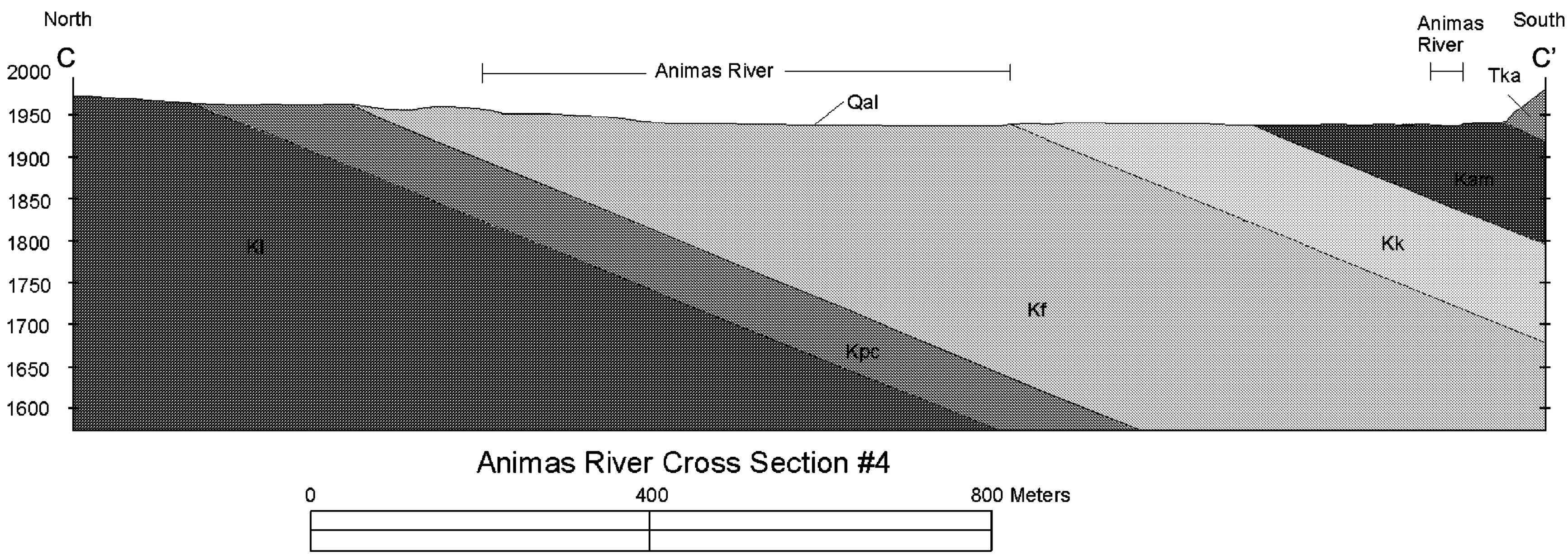


Figure 7 – Animas River Cross Section B to B'



Qal = Alluvium (approximately 1.3 m)
Tka = Animas Formation
Kam = McDermott Formation
Kk = Kirtland Formation
Kf = Fruitland Formation
Kpc = Pictured Cliffs Sandstone
Kl = Lewis Shale

Figure 8 – Animas River Cross Section C to C’

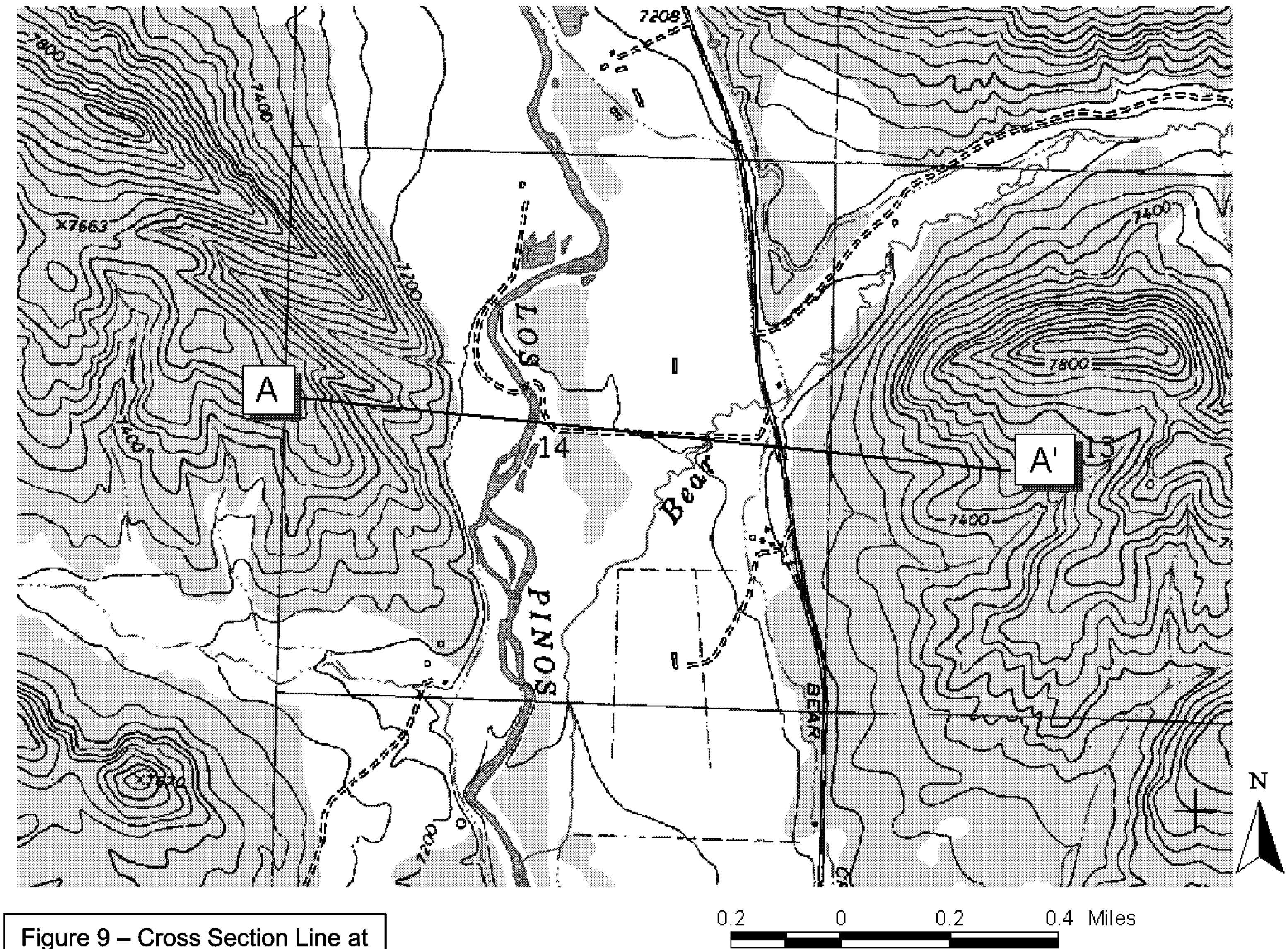


Figure 9 – Cross Section Line at Pine River

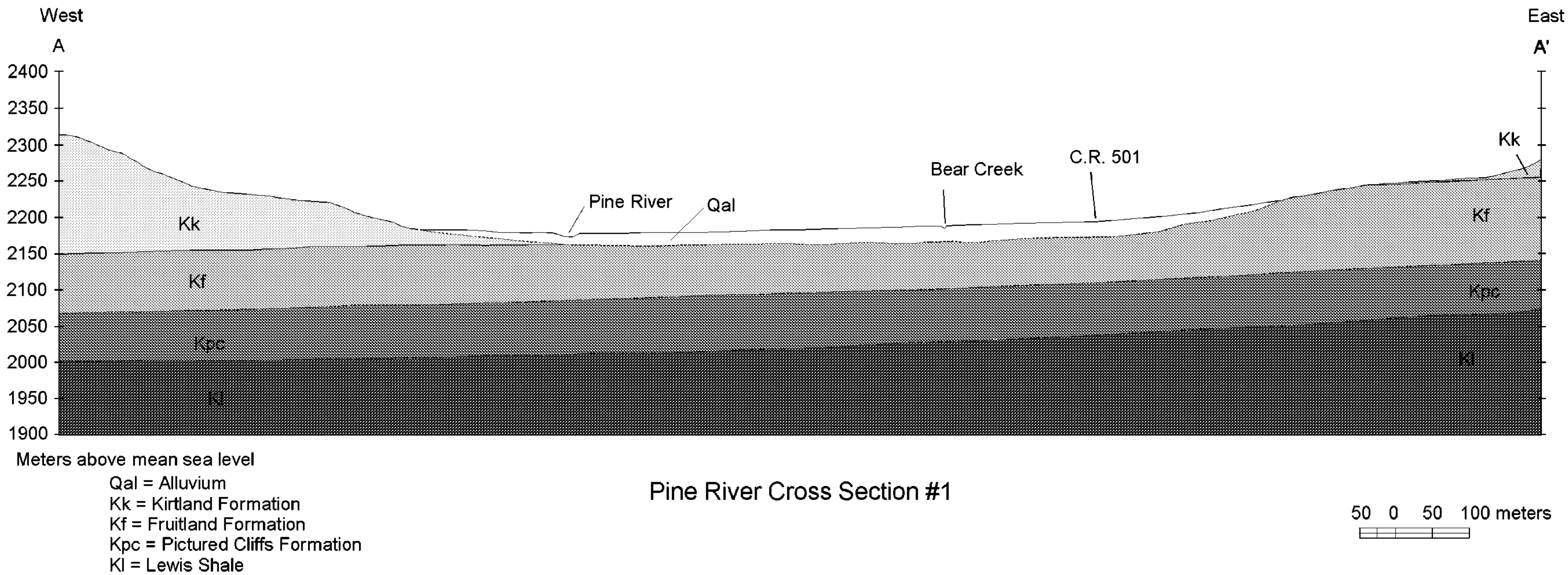


Figure 10 – Pine River Cross Section A to A'

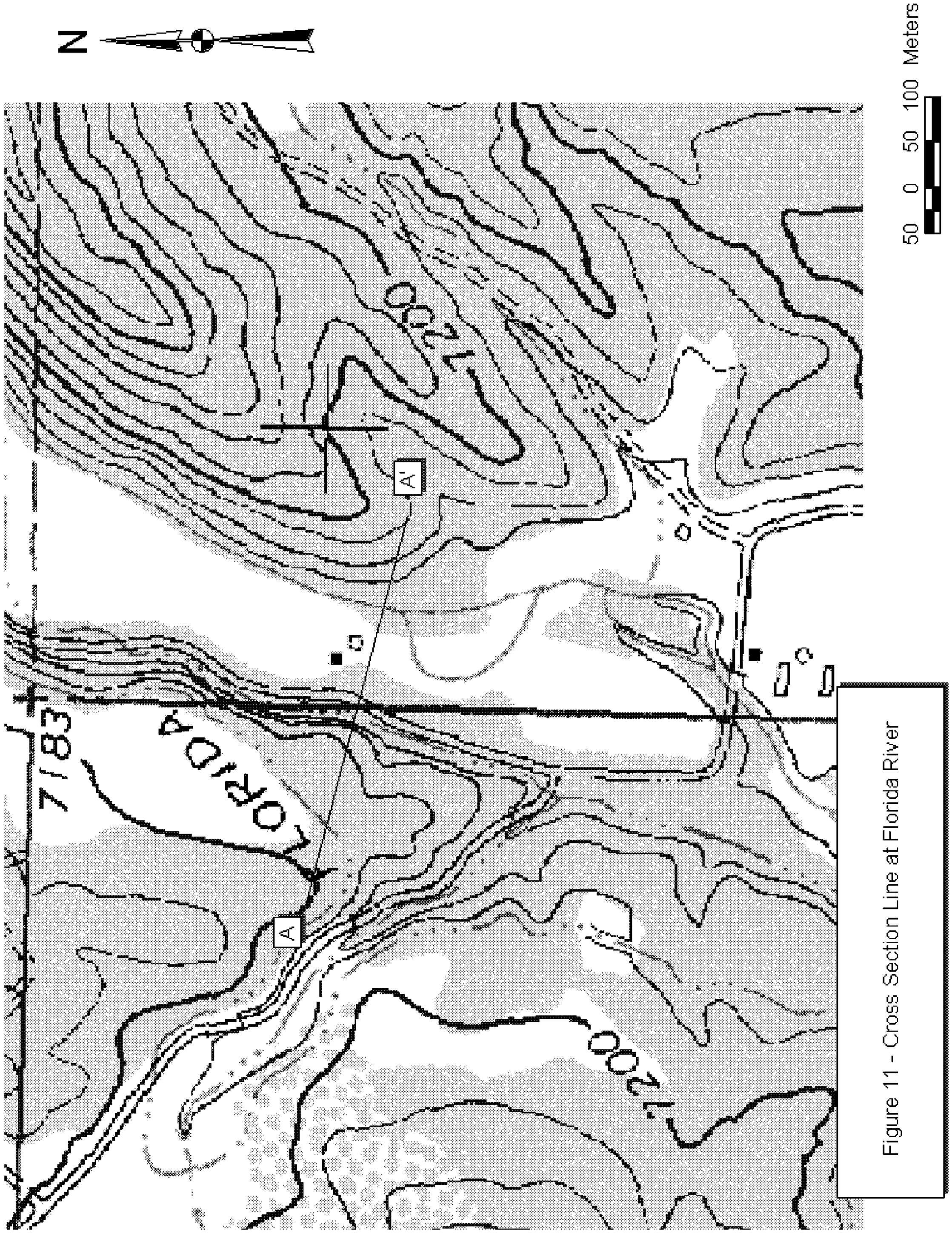


Figure 11 - Cross Section Line at Florida River

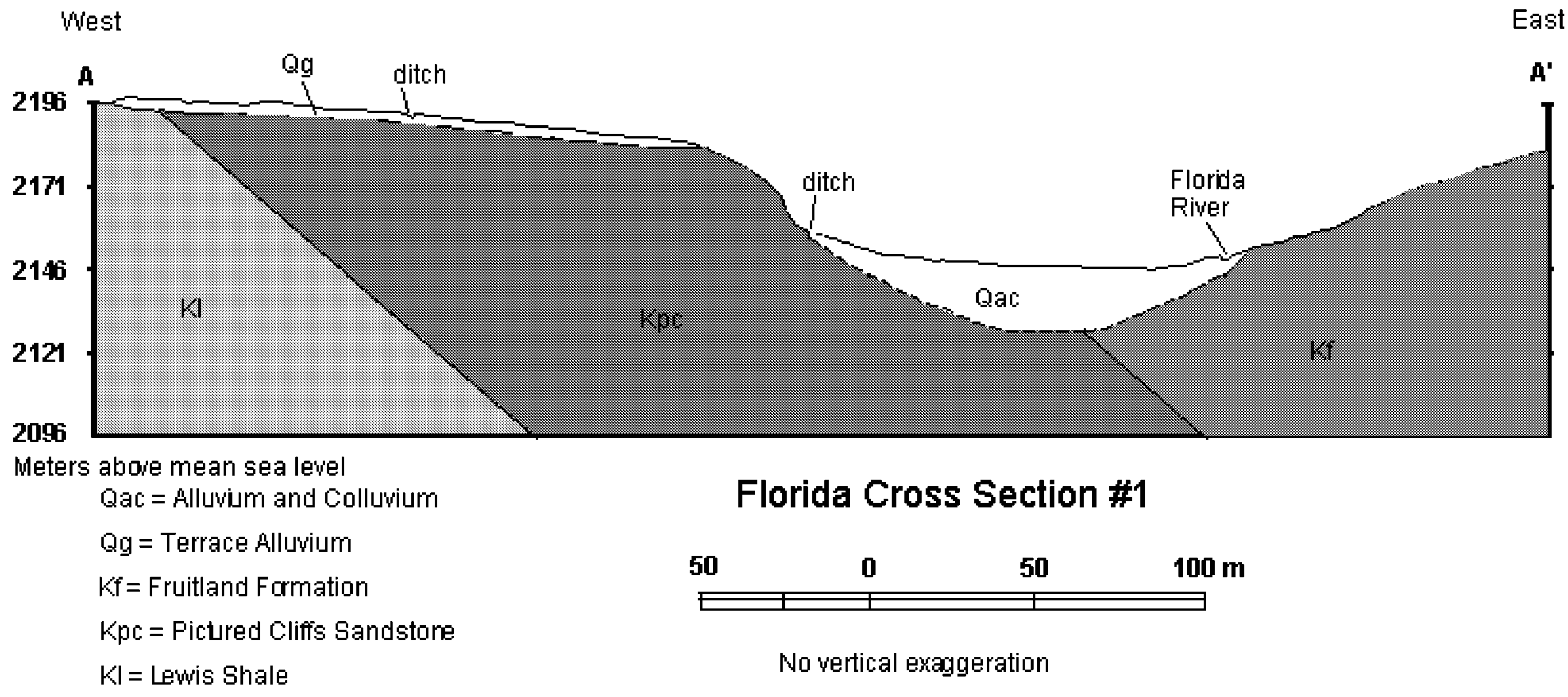


Figure 12 – Florida River Cross Section A to A'

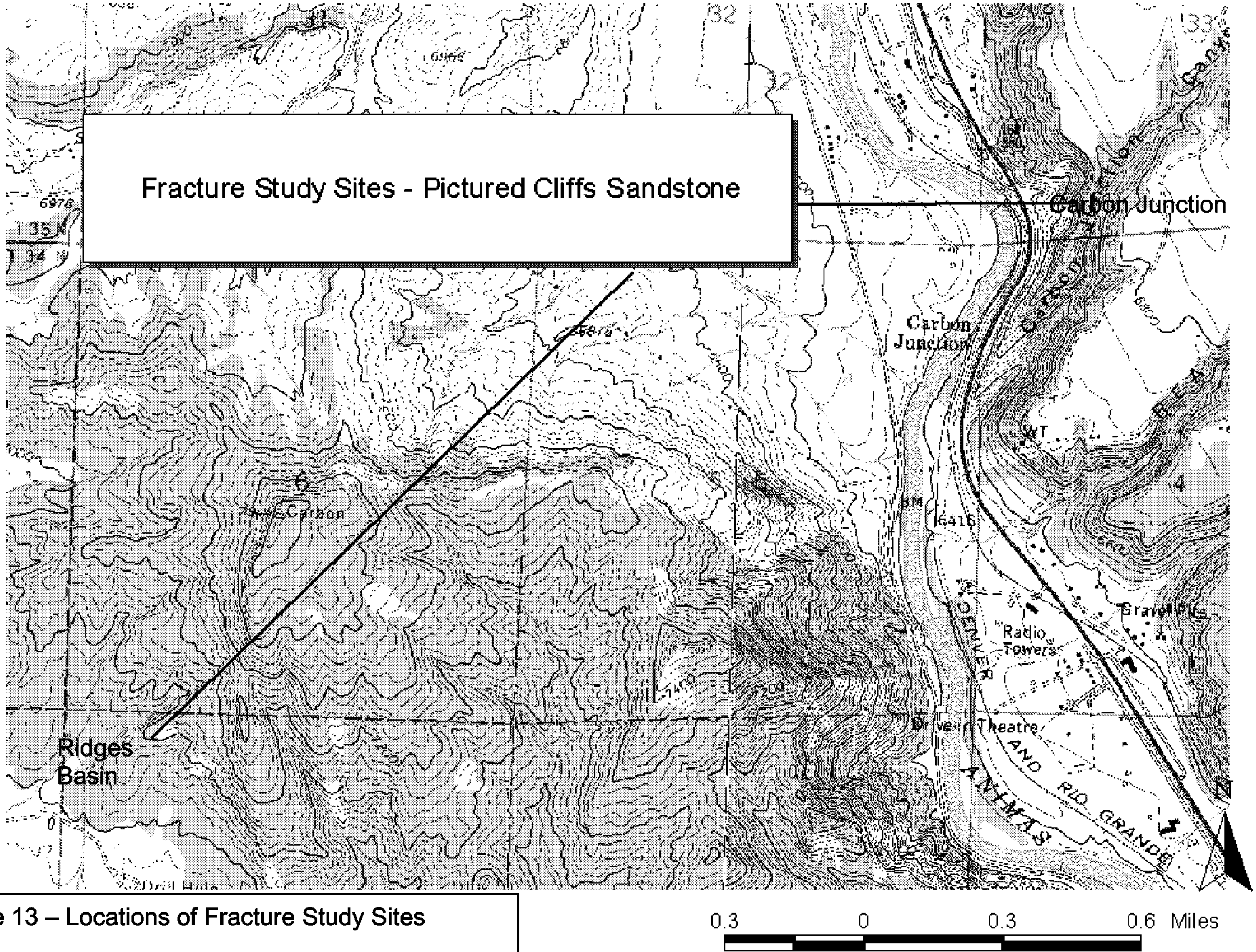


Figure 13 – Locations of Fracture Study Sites

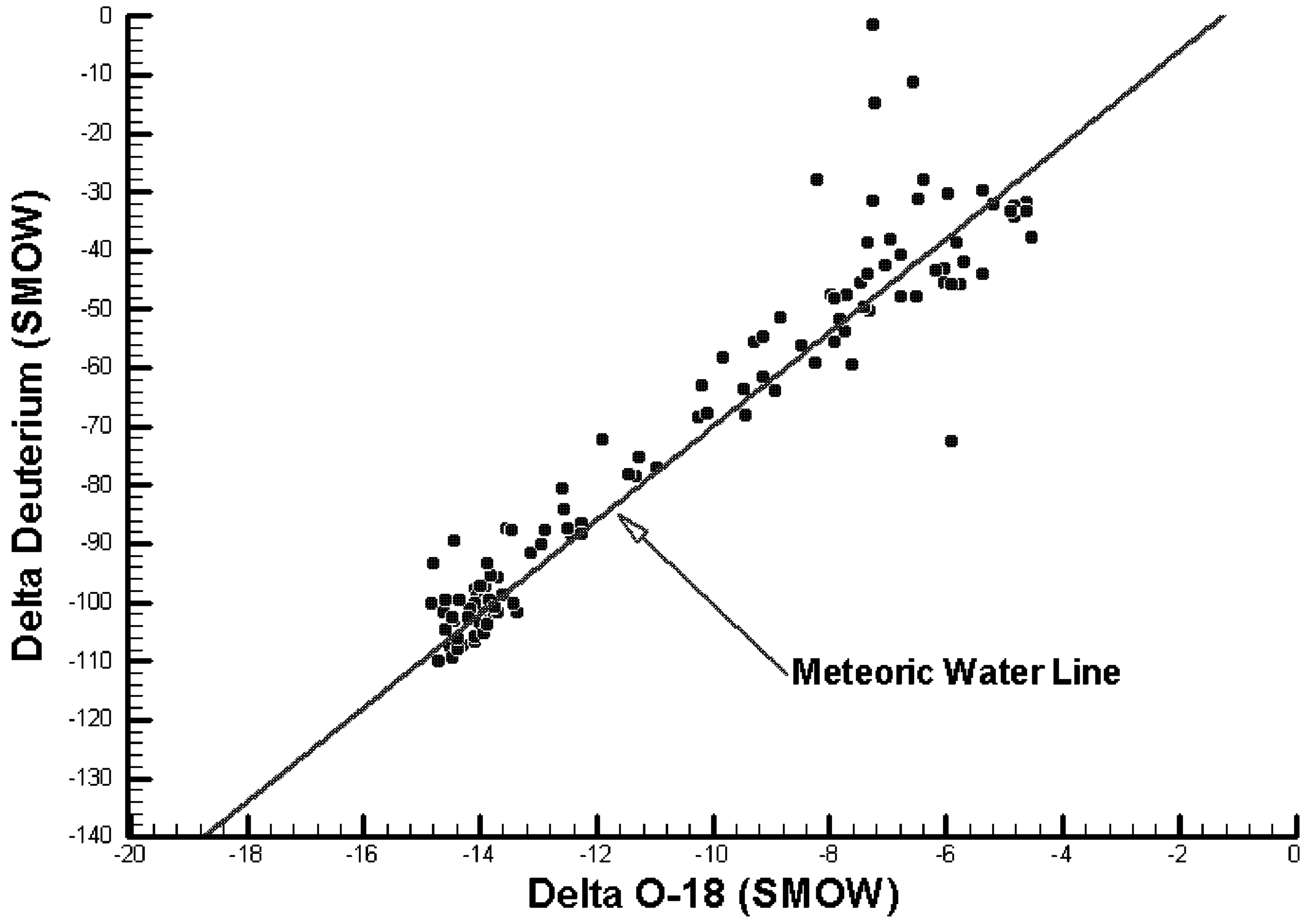


Figure 14 – Plot of Stable Isotopes in Fruitland Produced Water

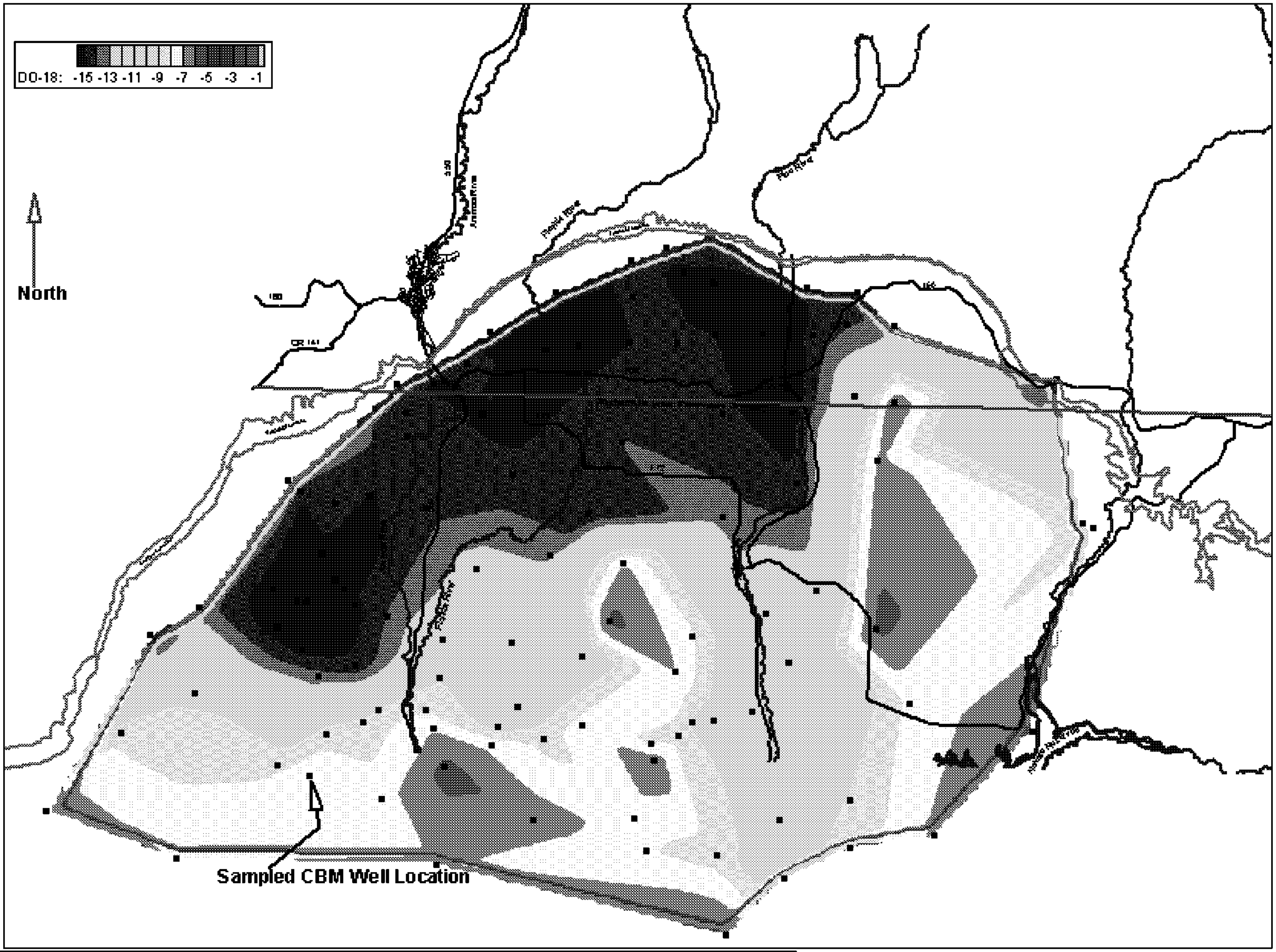


Figure 15 – Contour Plot of O-18 in Fruitland Produced Water

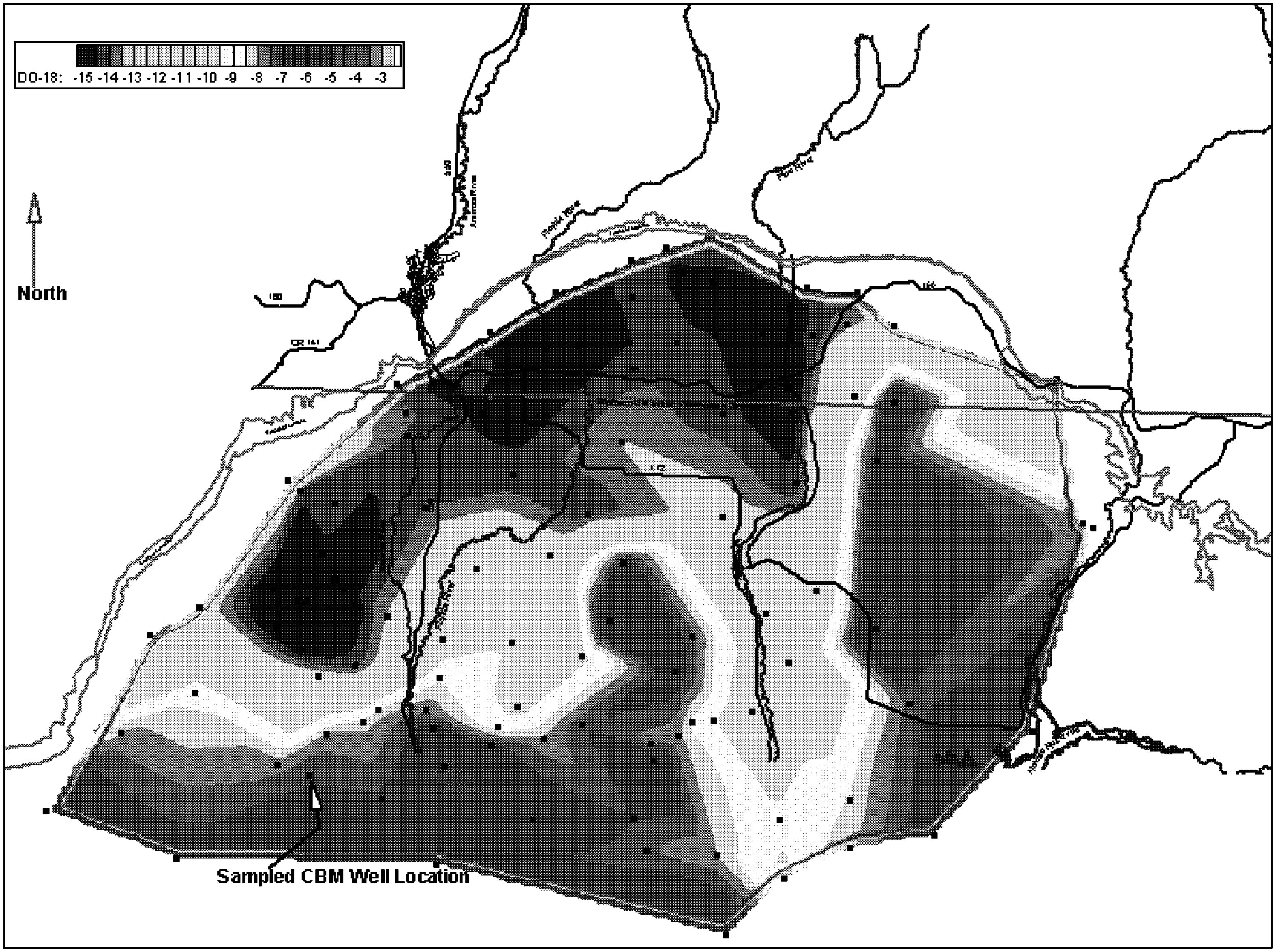


Figure 16 – Contour Plot of Deuterium in Fruitland Produced Water

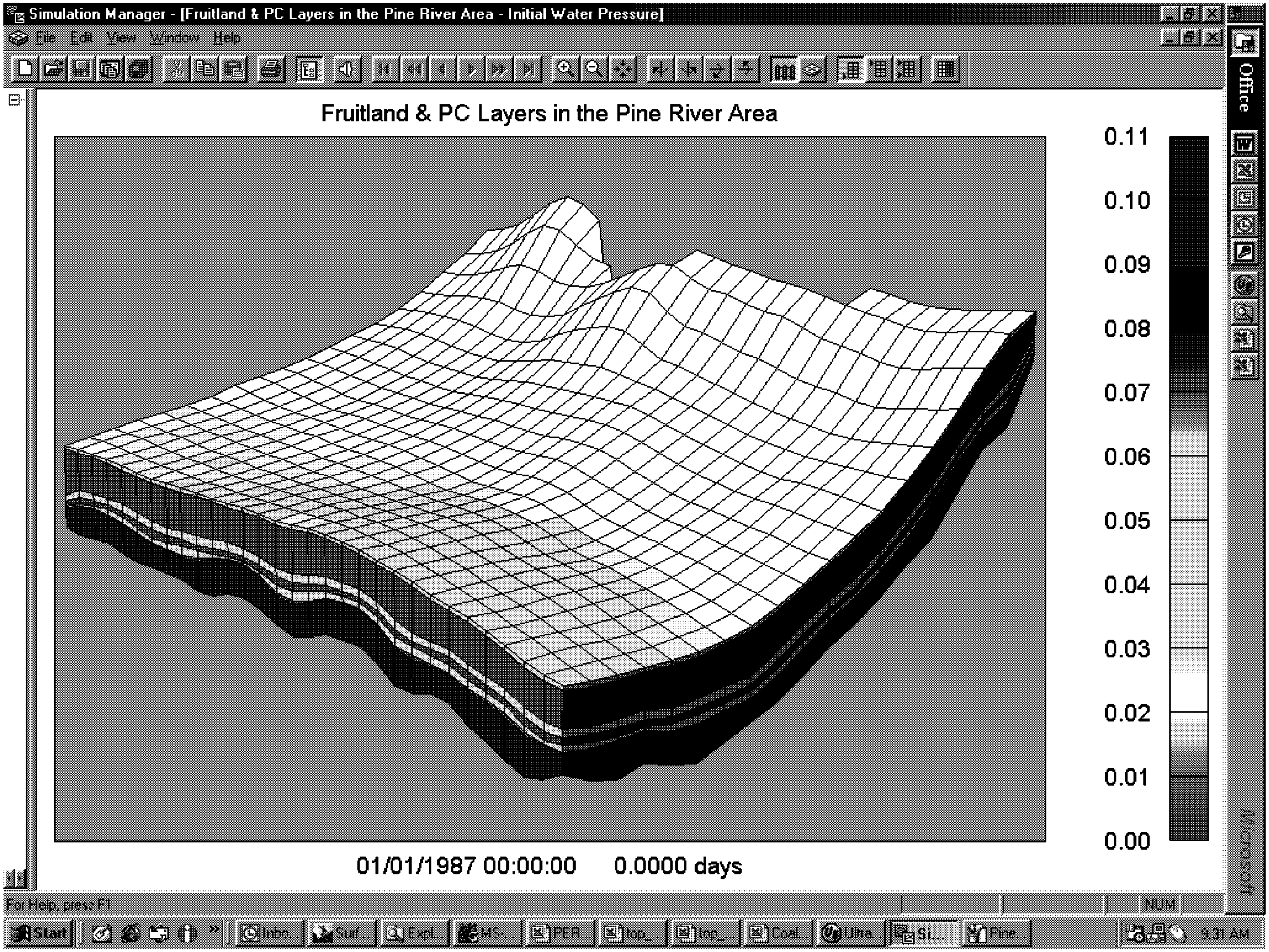


Figure 17 – Schematic of Model in Pine River Area; Blue is Pictured Cliffs, Yellow is Fruitland Coal Packages, Red is Fruitland Non-Coal Strata

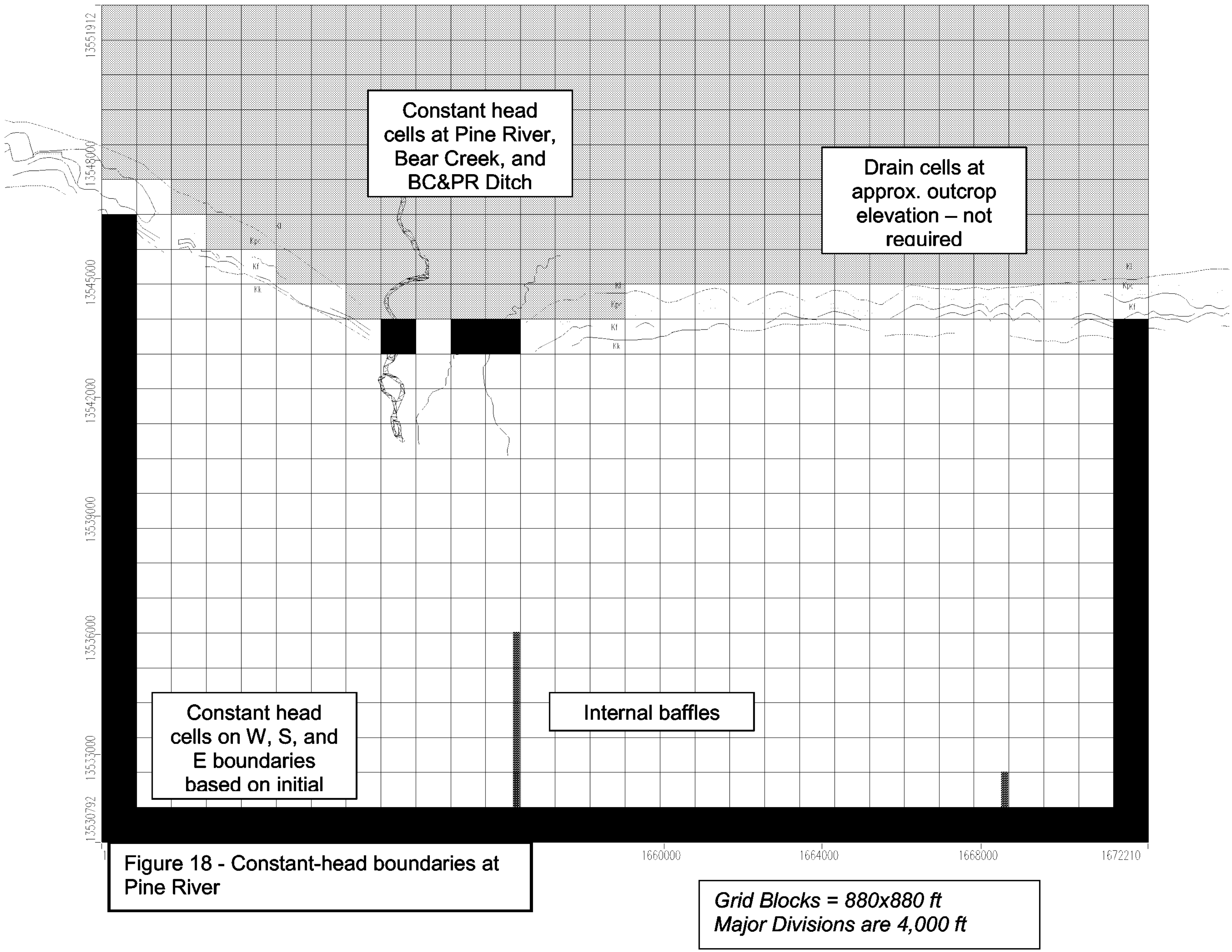


Figure 18 - Constant-head boundaries at Pine River

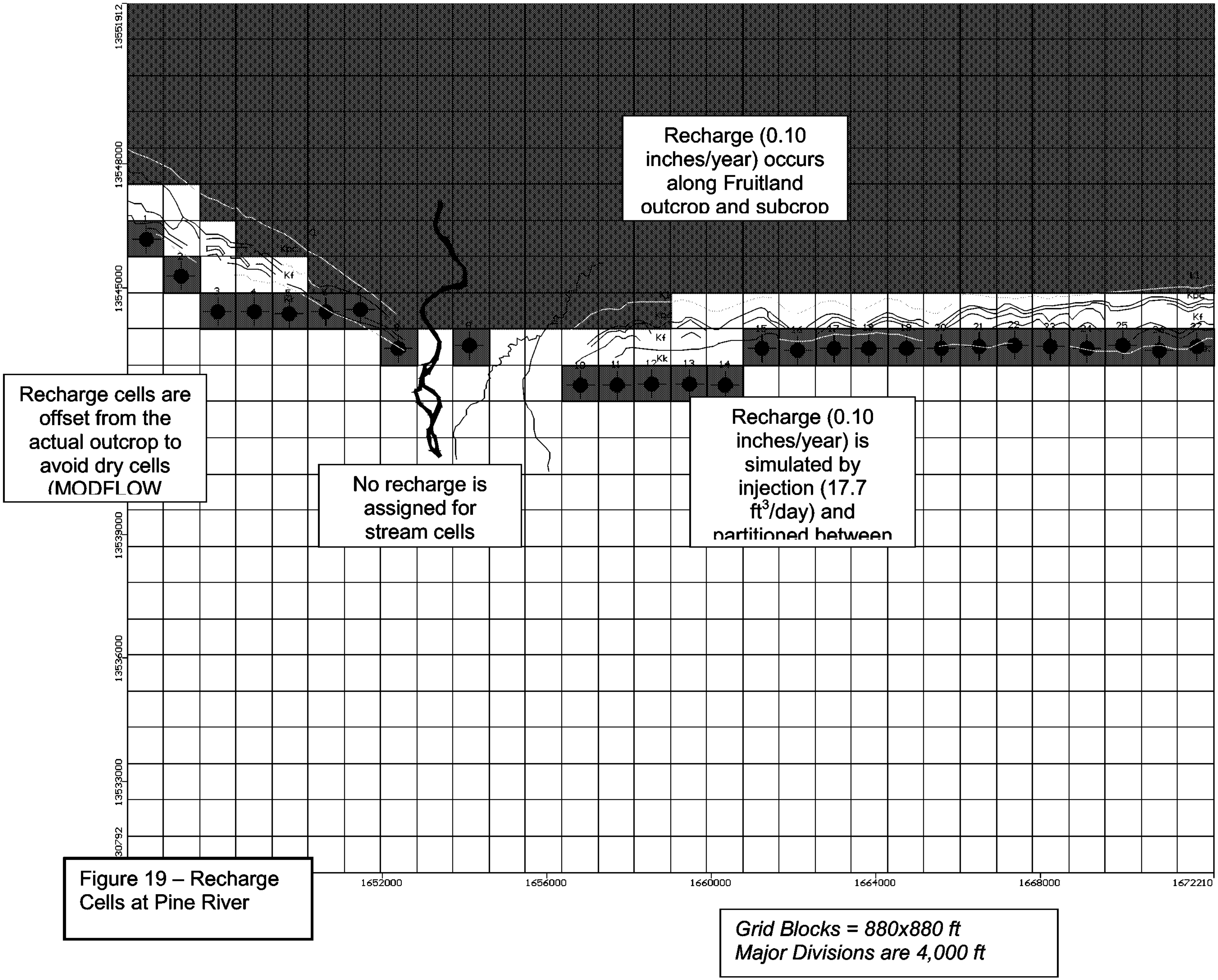


Figure 19 – Recharge Cells at Pine River

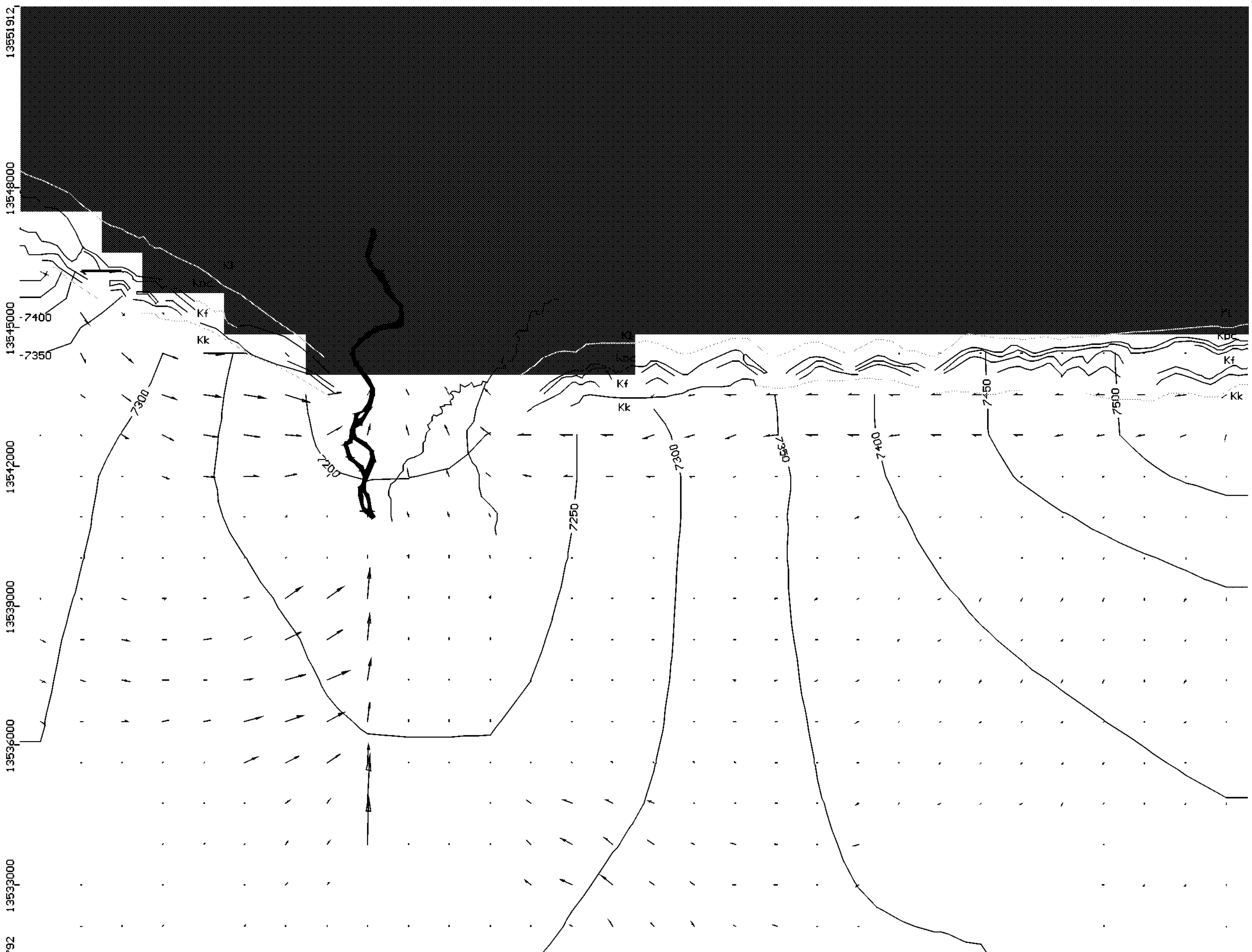


Figure 20 – Flow Velocity Vectors and Potentiometric Contours in Coal Layer at Pine River

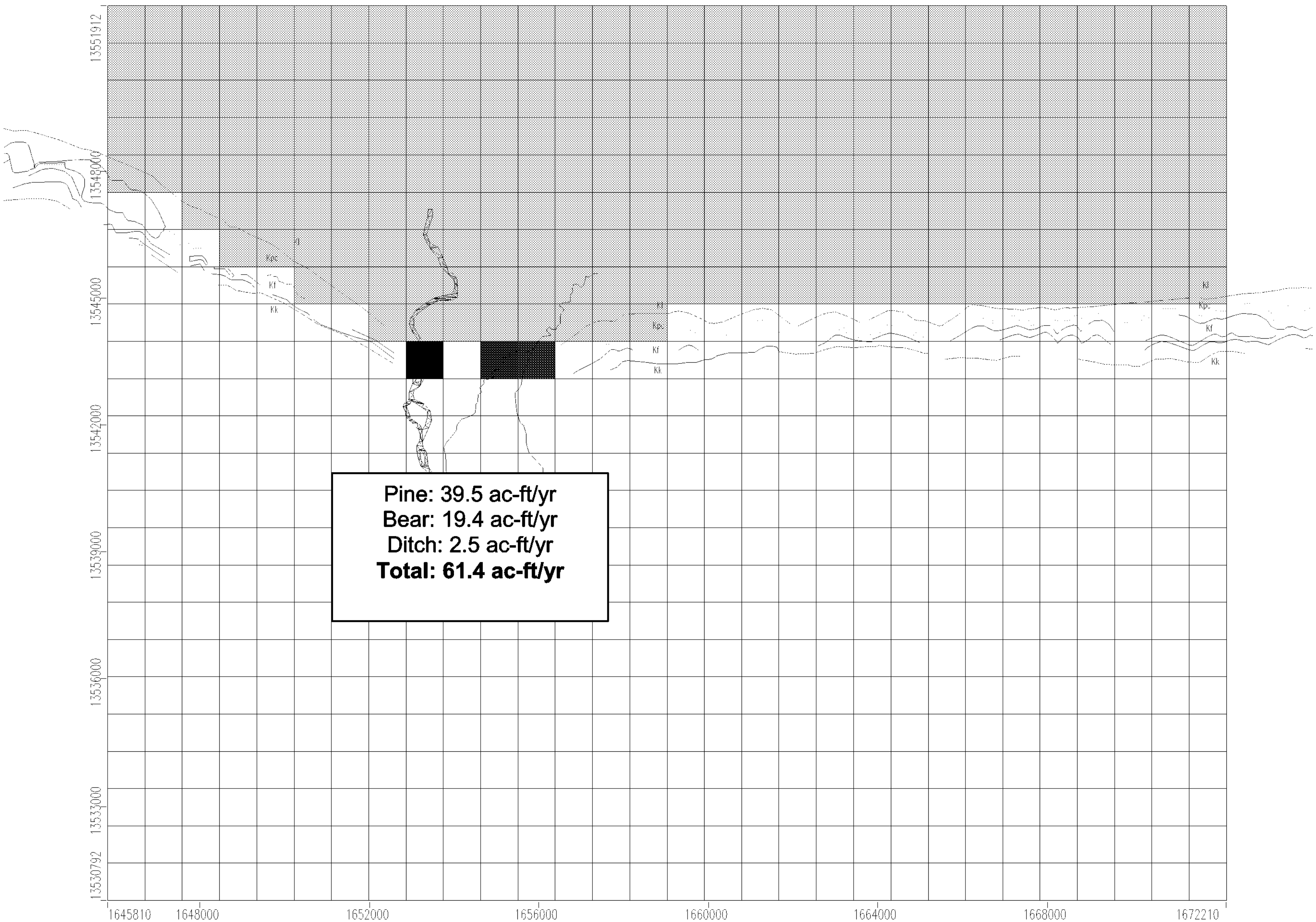


Figure 21 – Ground Water Discharge Rates at Pine River

Grid Blocks = 880x880 ft
Major Divisions are 4,000 ft

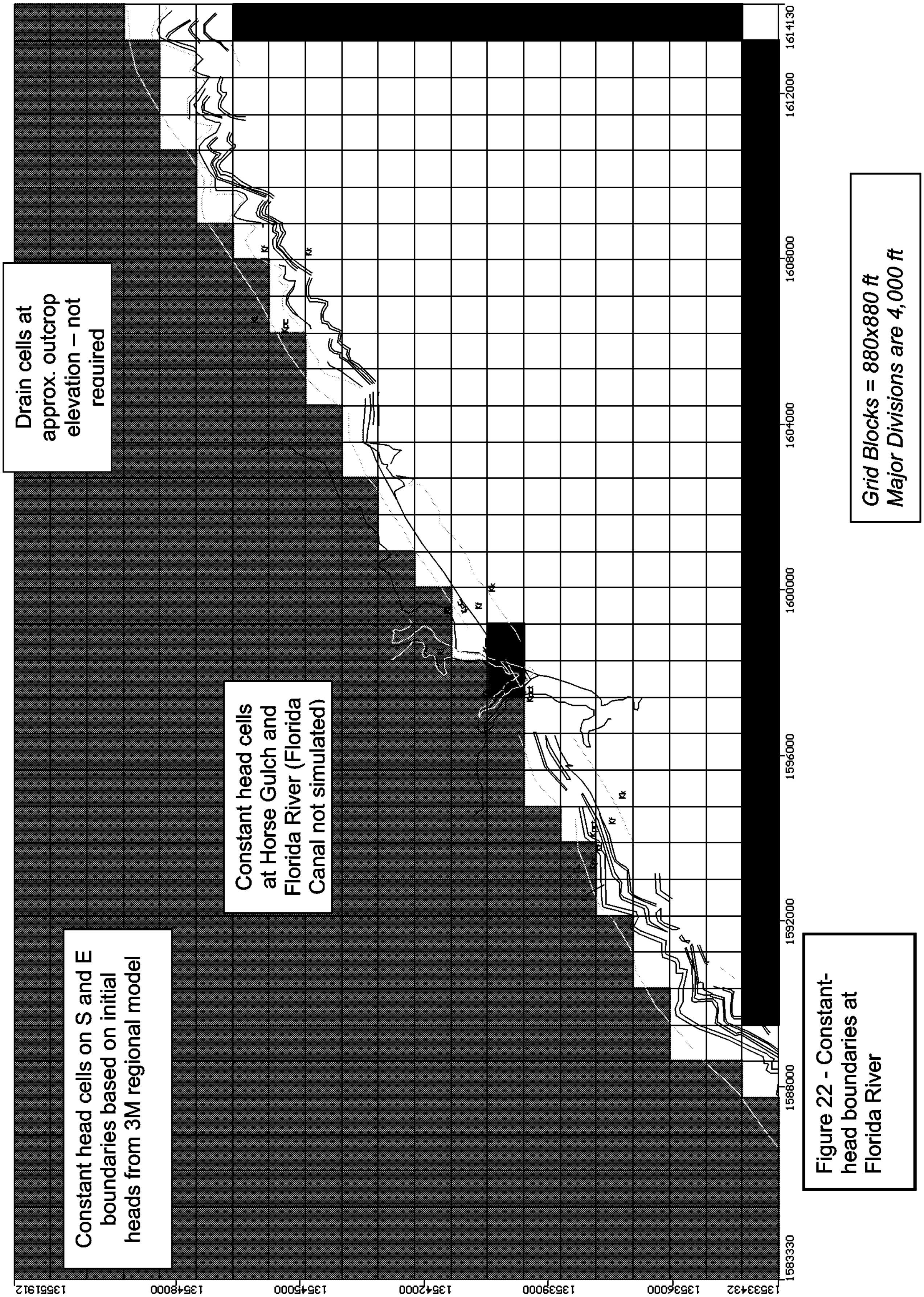


Figure 22 - Constant-head boundaries at Florida River

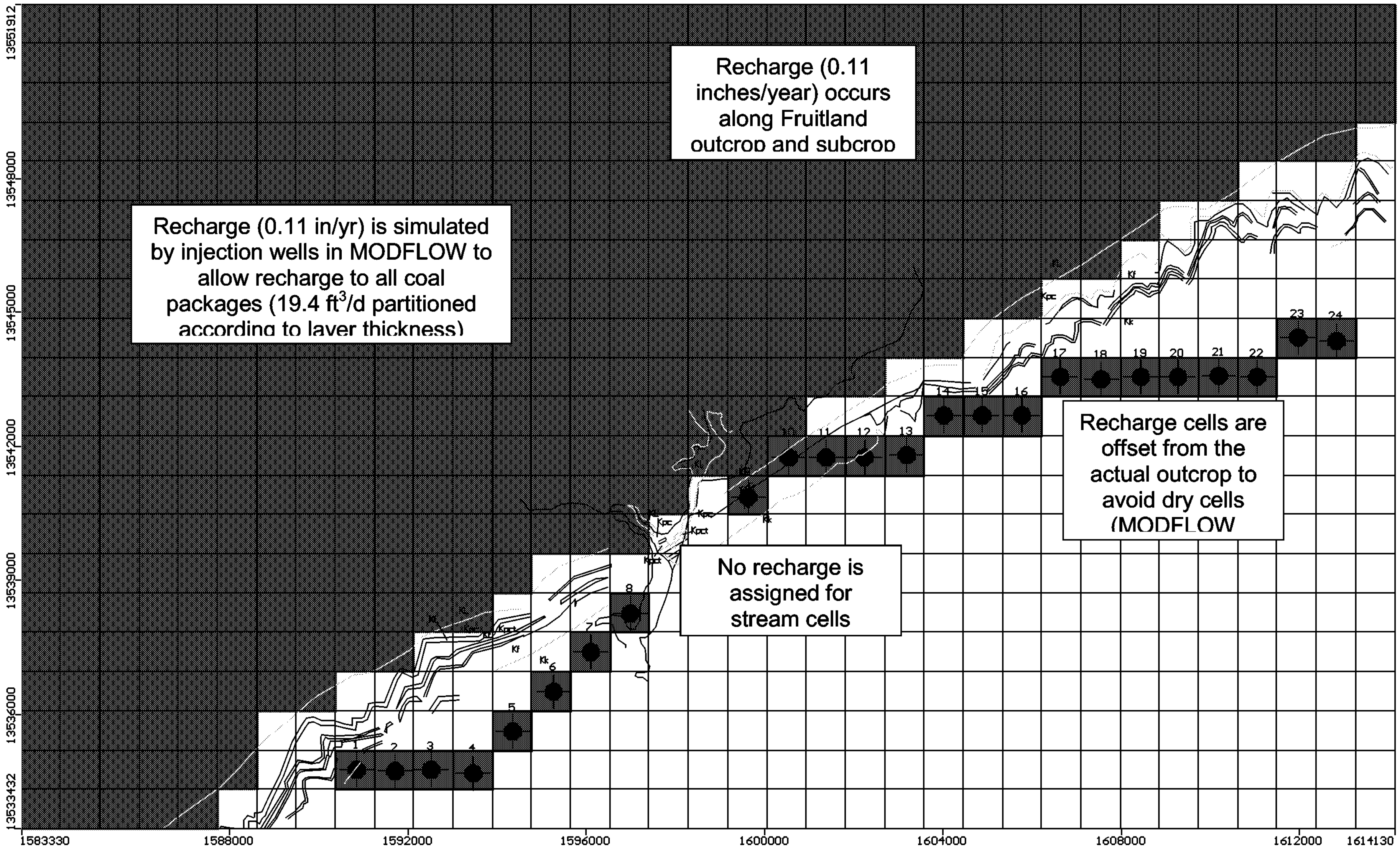


Figure 23 – Recharge Cells at Florida River

Grid Blocks = 880x880 ft
Major Divisions are 4,000 ft

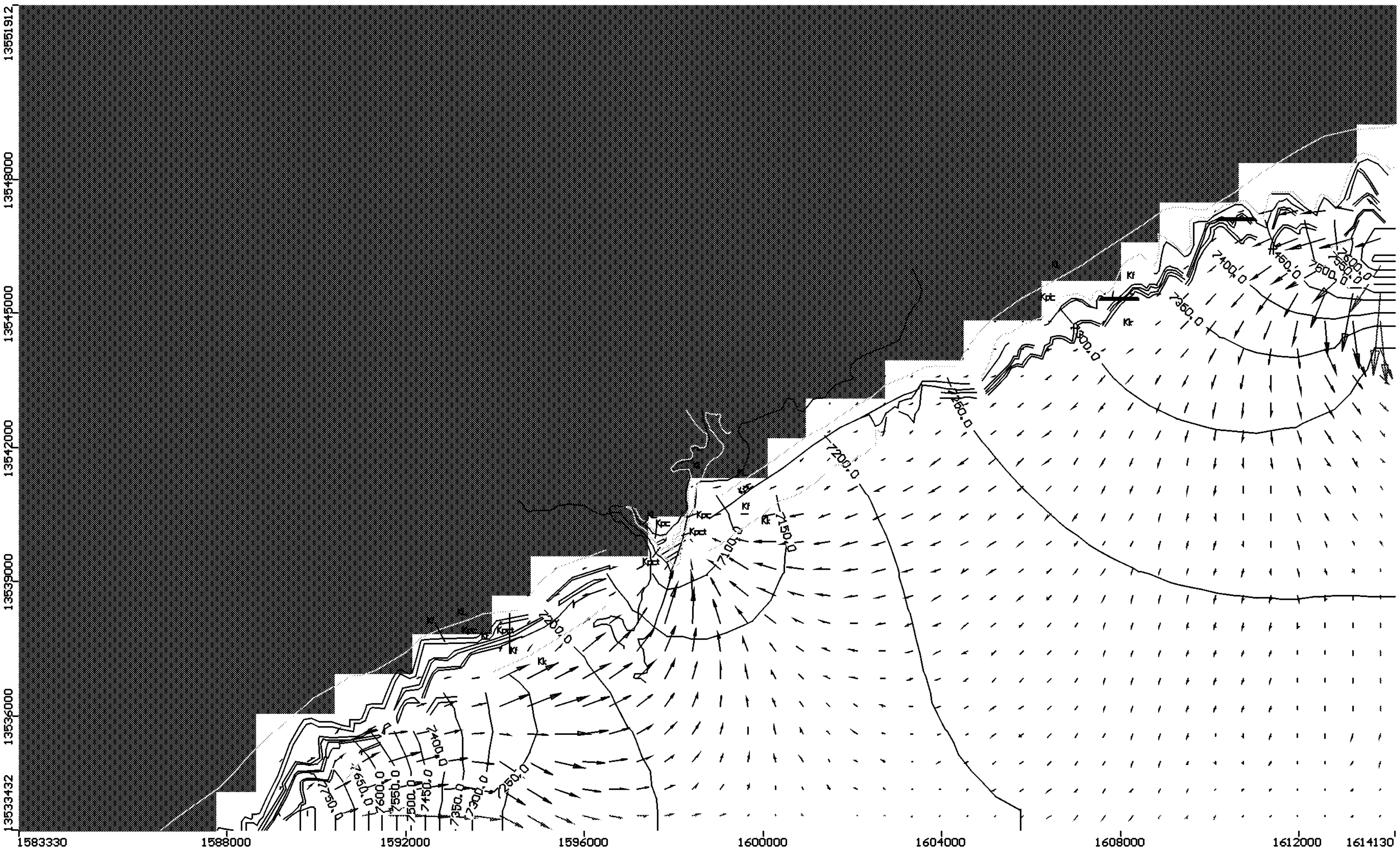


Figure 24 – Ground Water Velocity Vectors and Potentiometric Contours in Coal Layer; Florida River

Major Divisions are 4,000 ft

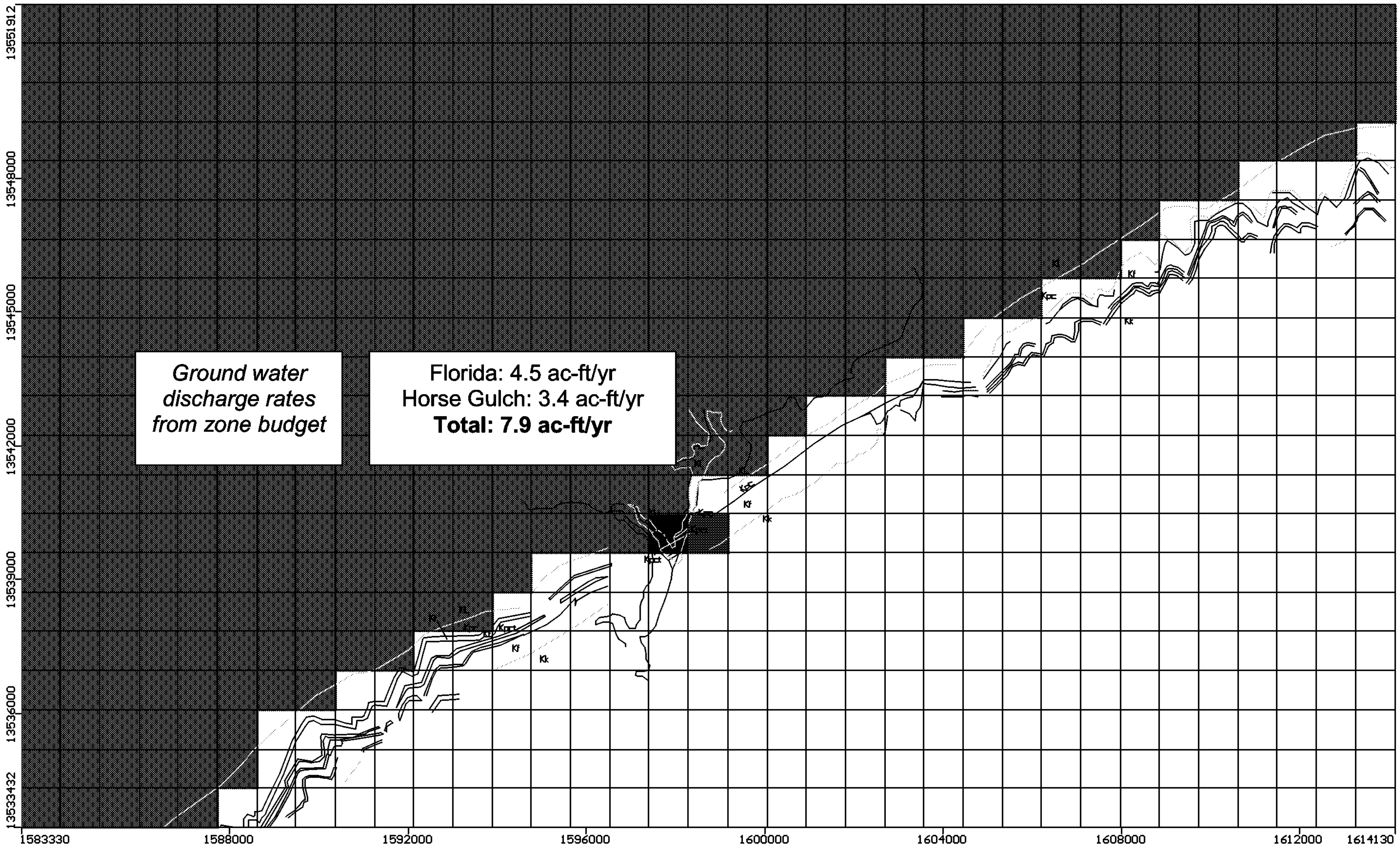


Figure 25 – Ground Water Discharge Rates at Florida River

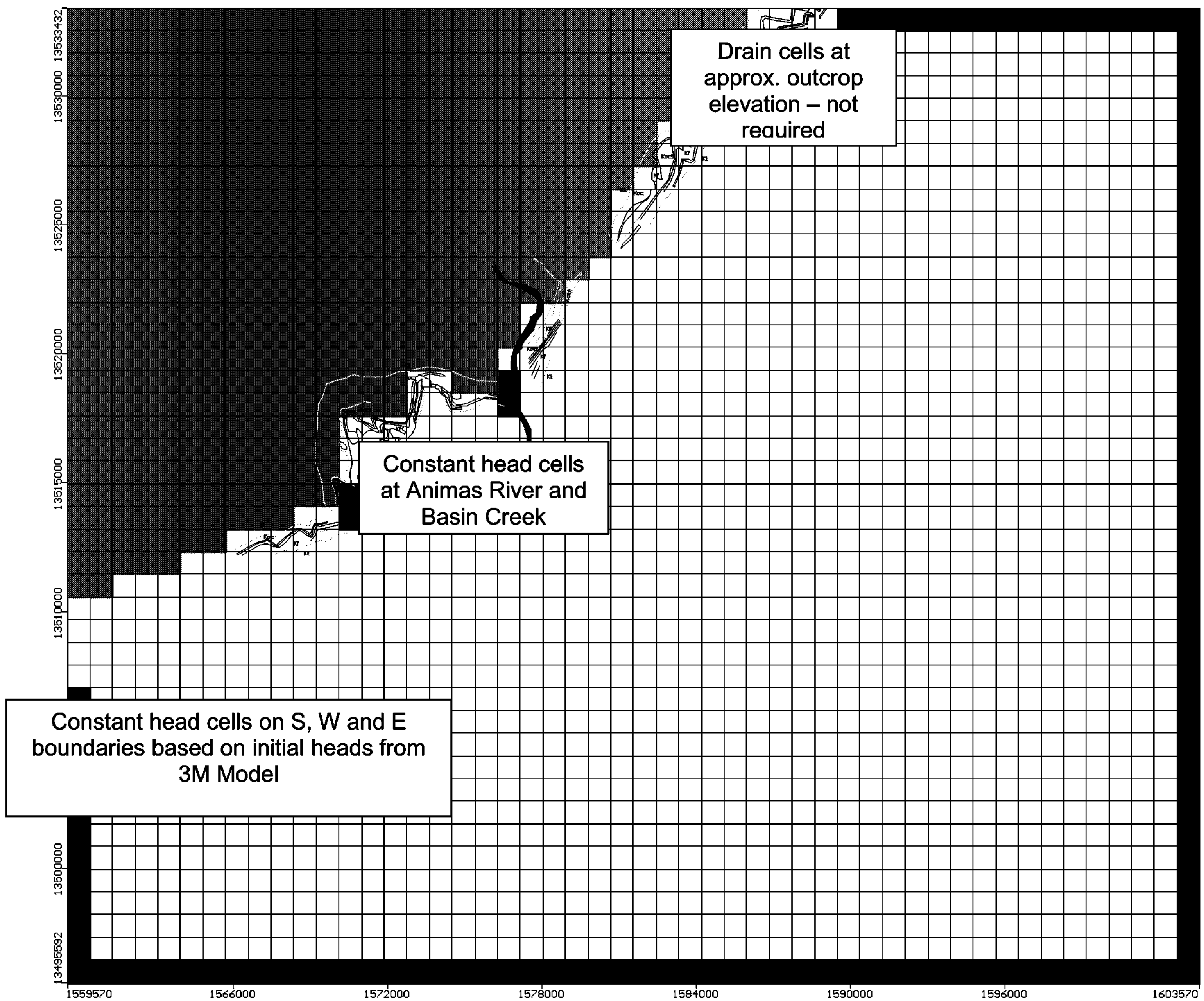


Figure 26 – Constant-head Boundaries at Animas River

Grid Blocks = 880x880 ft
Major Divisions are 4,000 ft

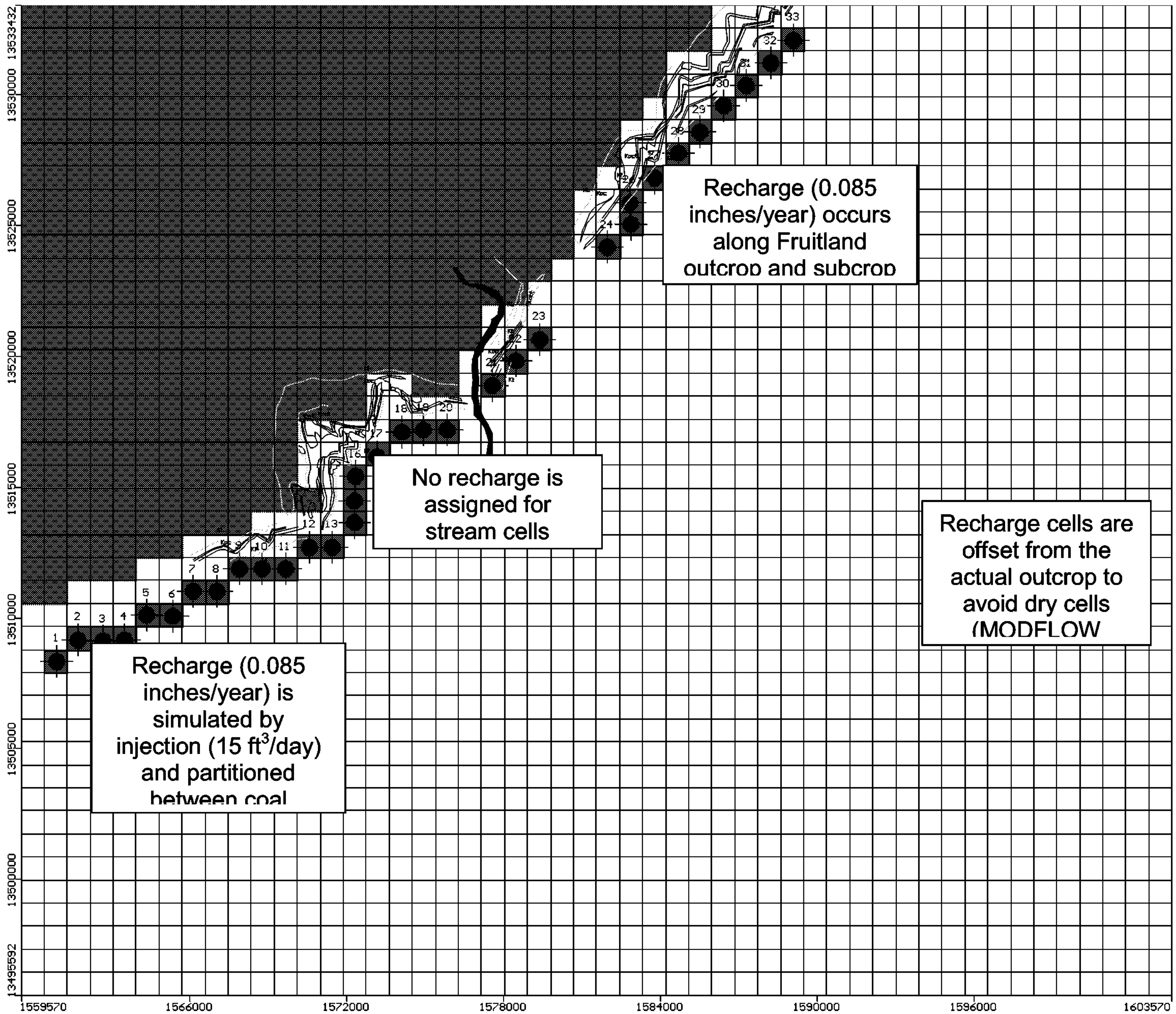


Figure 27 – Recharge Cells at Animas River

Grid Blocks = 880x880 ft
Major Divisions are 4,000 ft

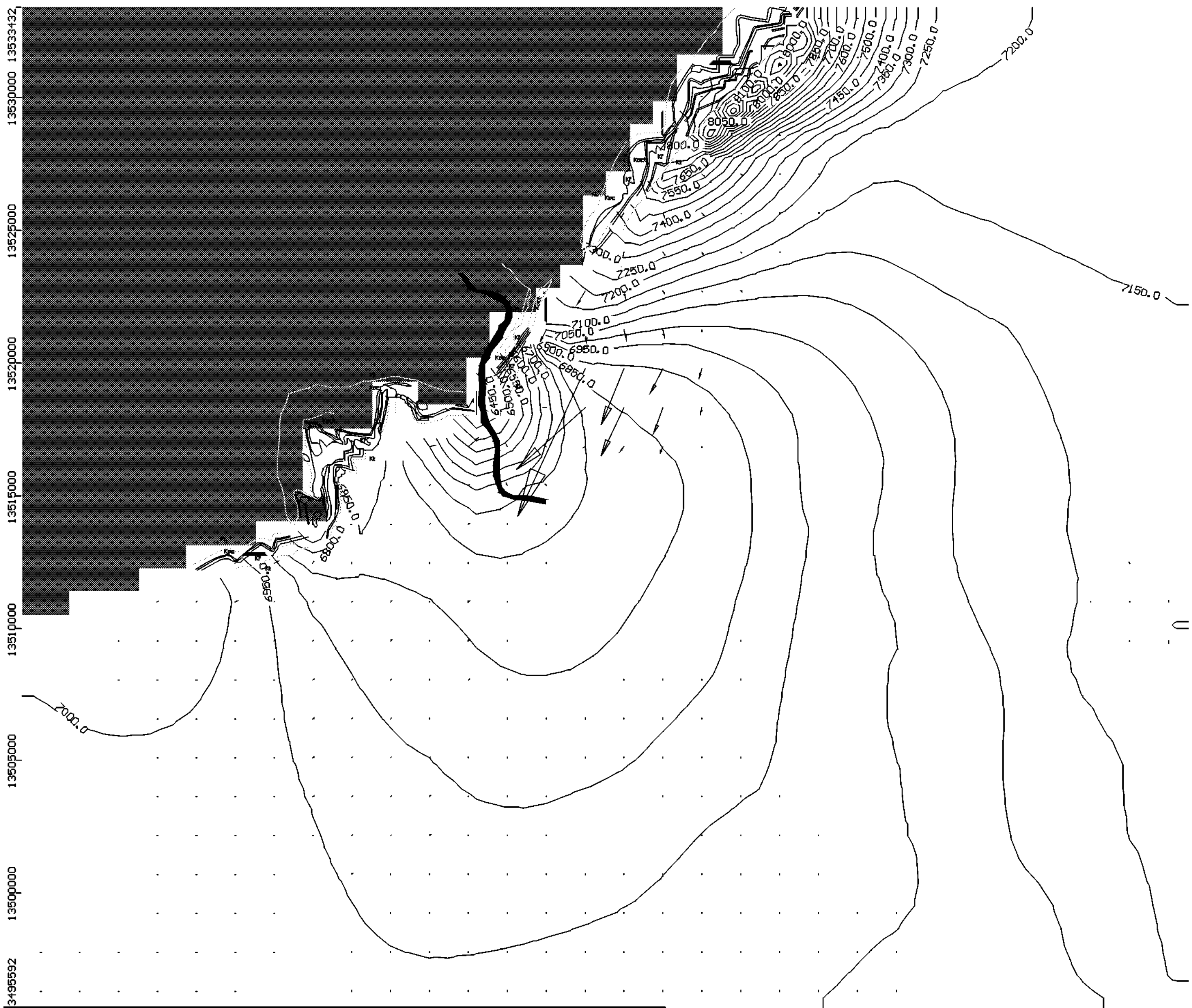


Figure 28 – Ground Water Velocity Vectors and Potentiometric Contours at Animas River

Major Divisions are 4,000 ft

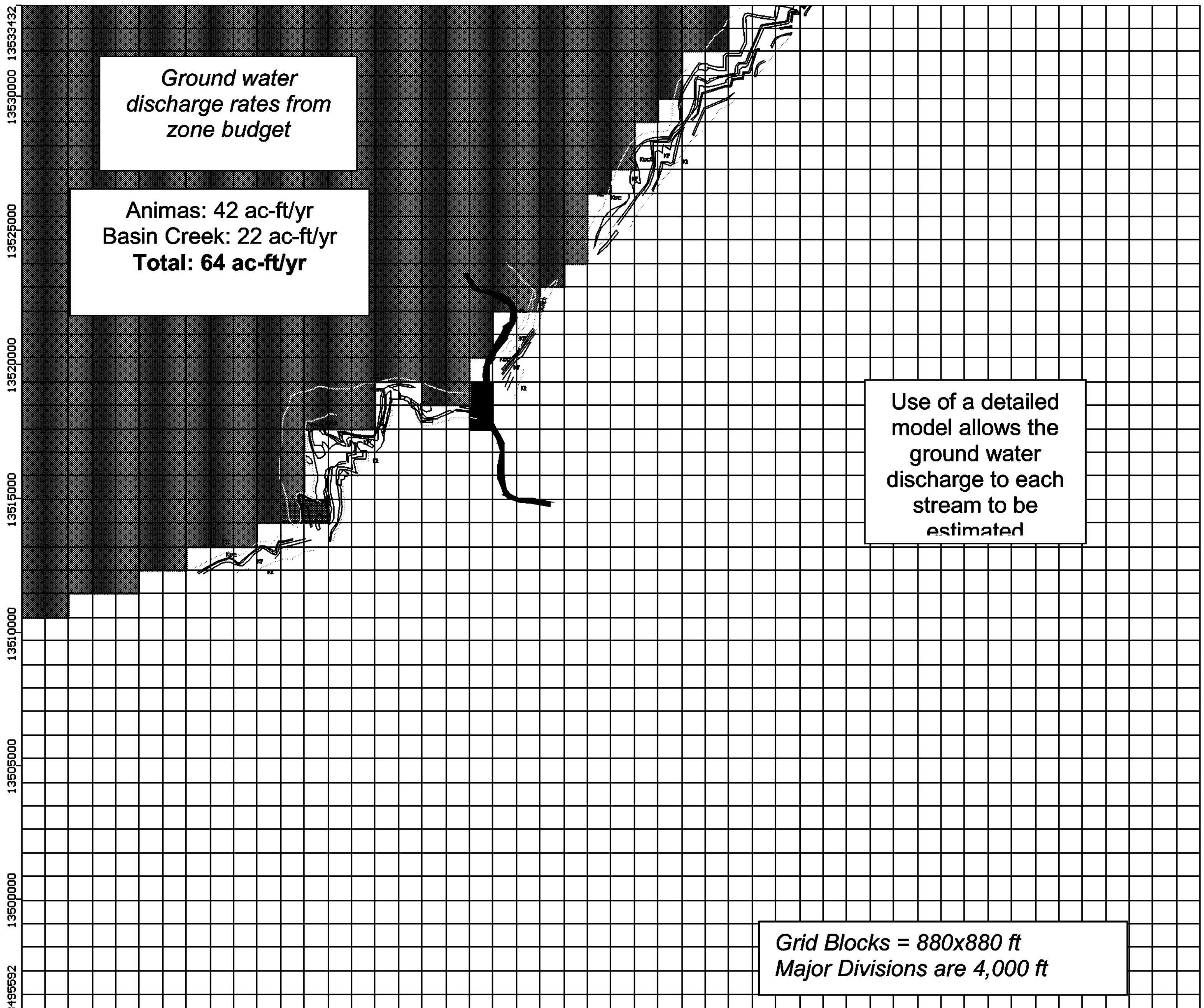


Figure 29 – Ground Water Discharge Rates at Animas River

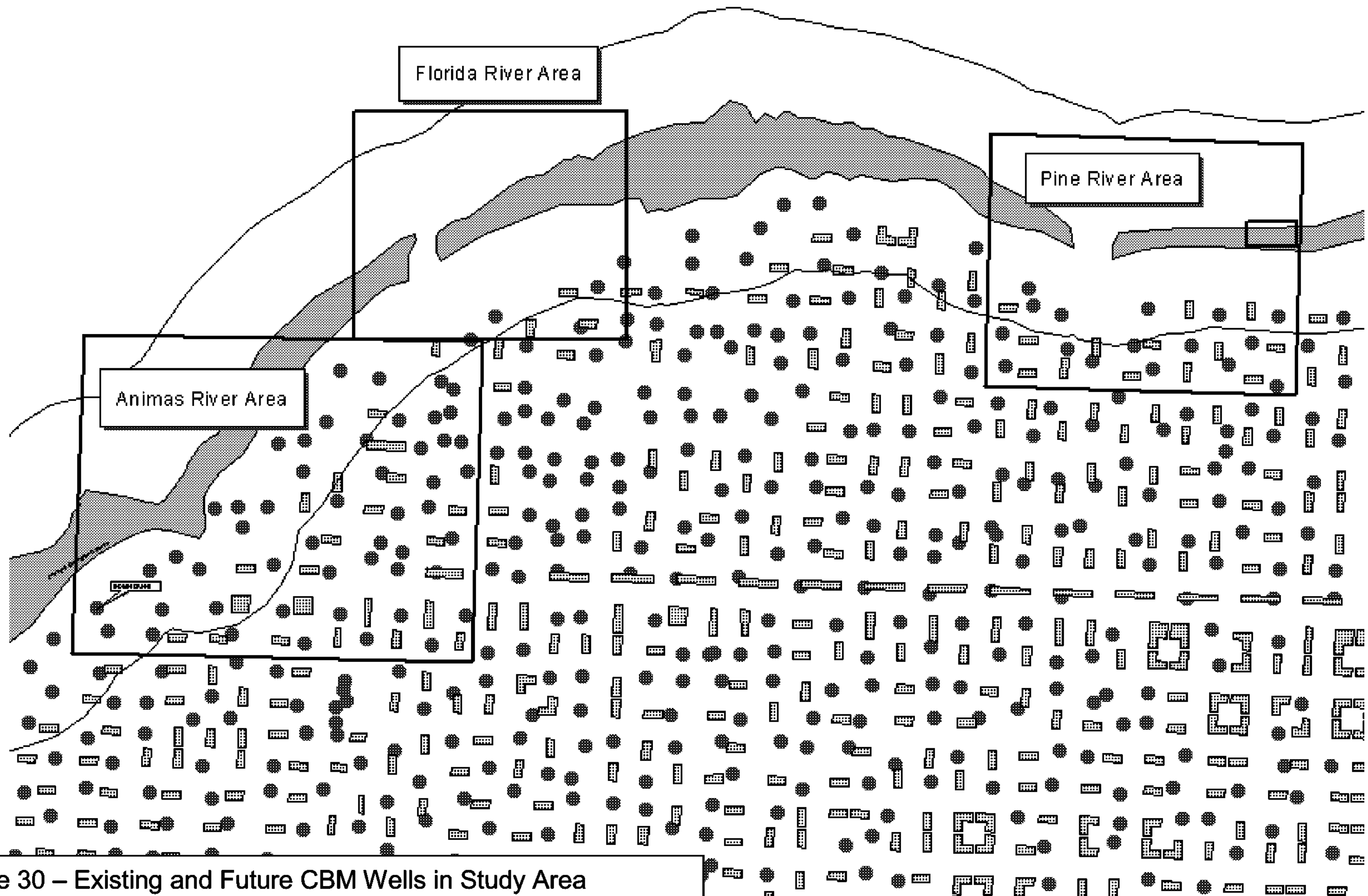


Figure 30 – Existing and Future CBM Wells in Study Area
(Existing wells are red points, future wells are rectangles)

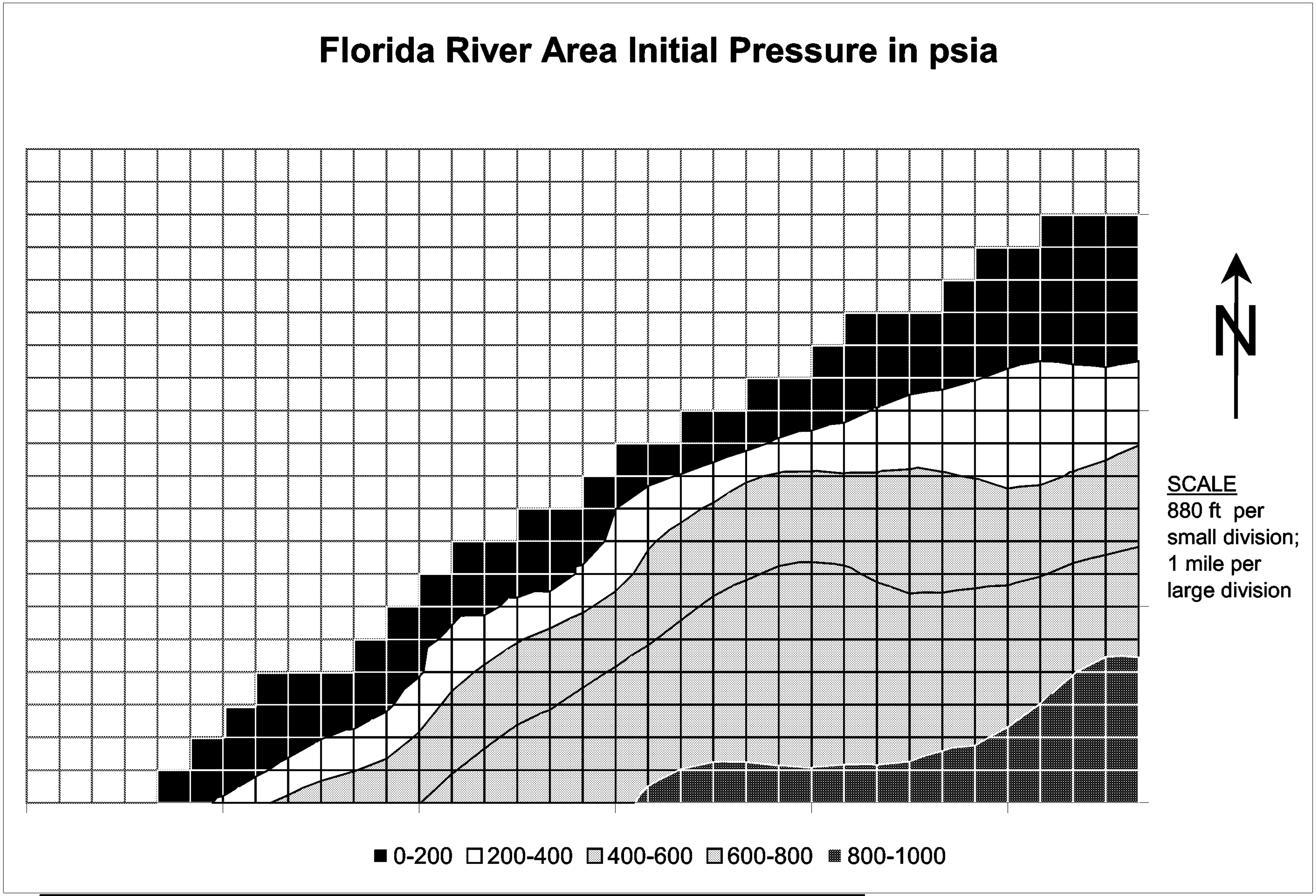


Figure 31 – Initial CBM Reservoir Pressures; Florida River Area

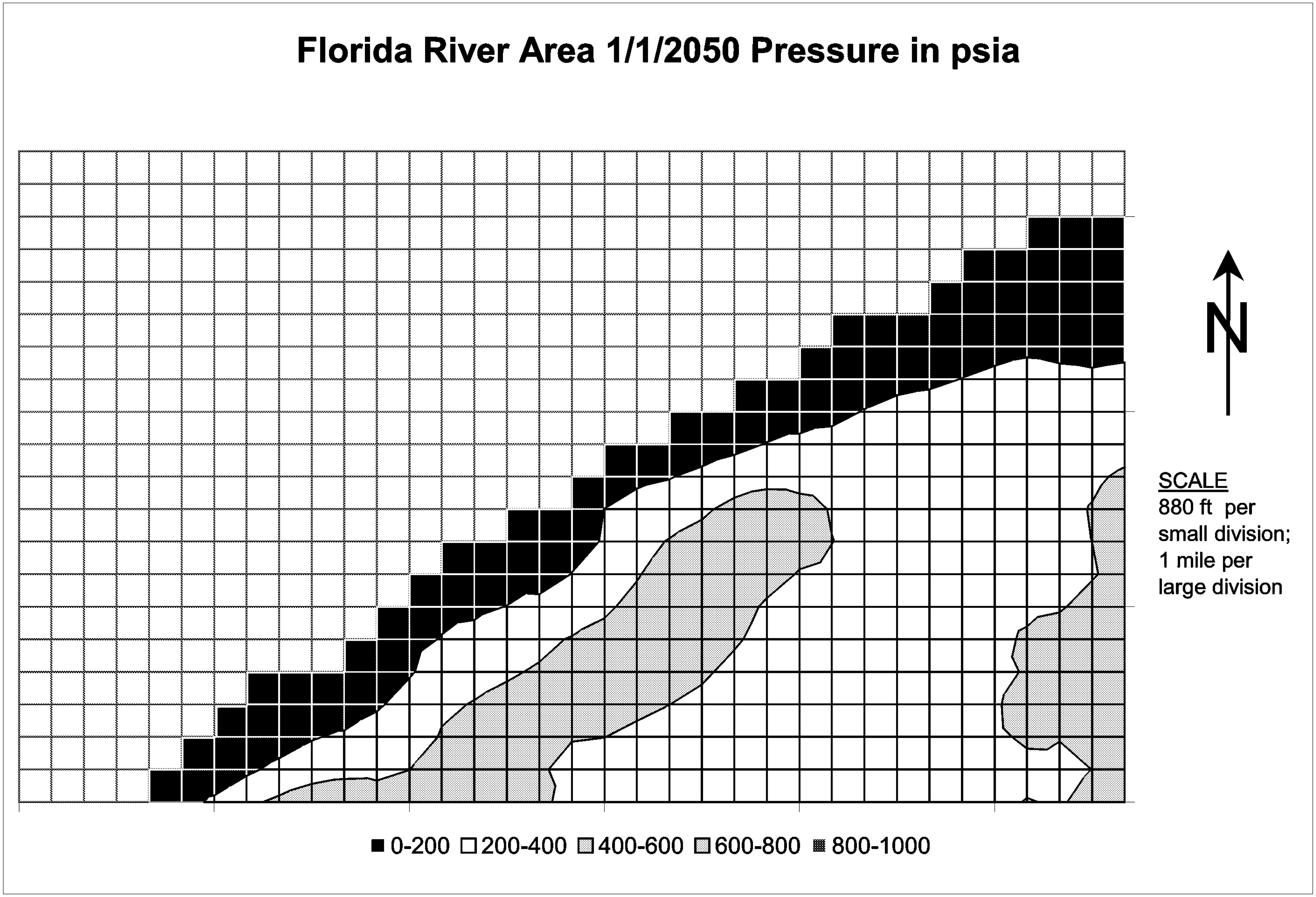


Figure 32 – Reservoir Pressures, Year 2050; Florida River Area

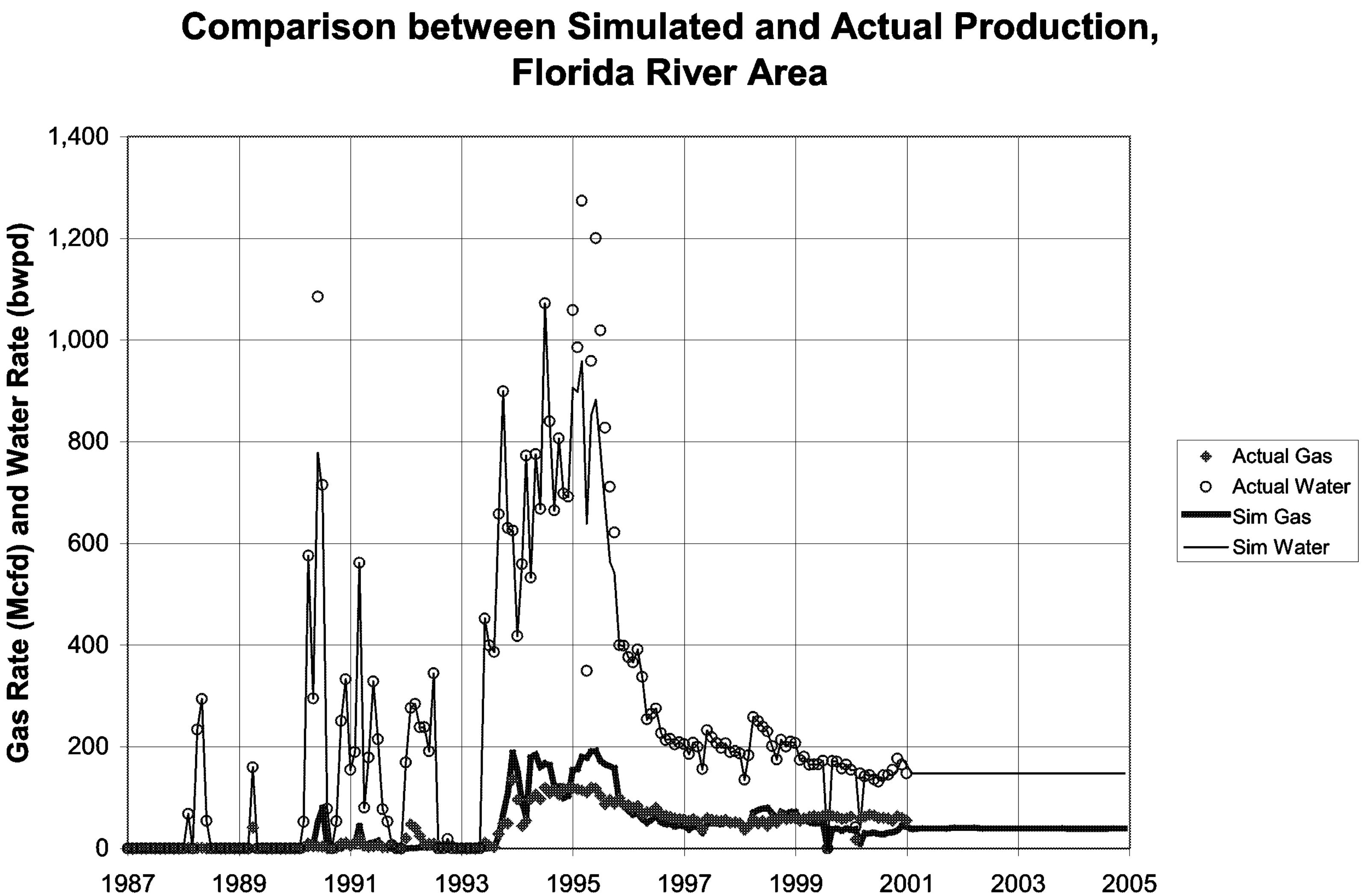


Figure 33 – Simulated vs. Actual Cumulative Gas and Water Production for Florida River Model

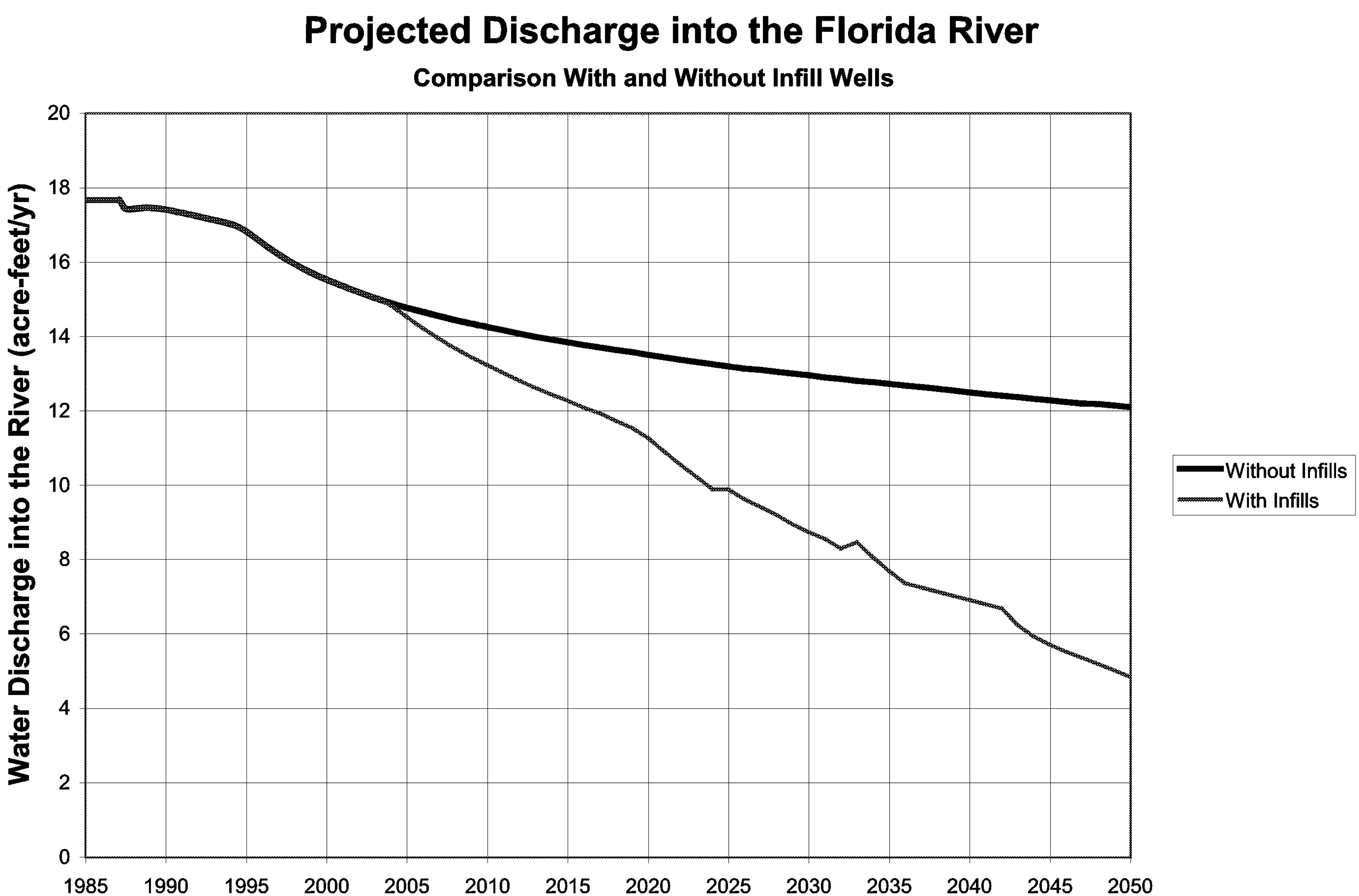


Figure 34 – Water Discharge Rates From Fruitland and Pictured Cliffs Formations into Florida River (Infills refers to future wells)

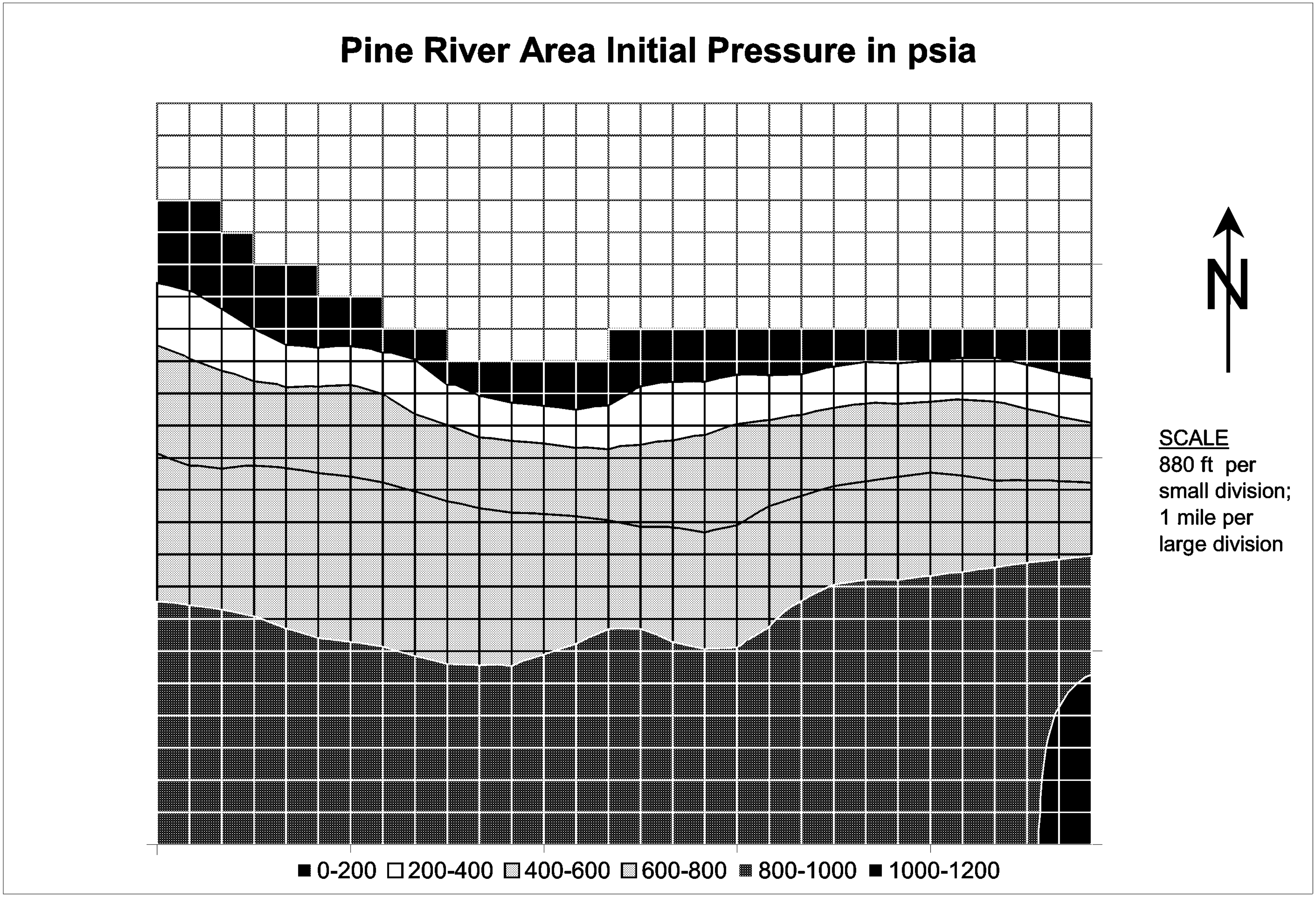


Figure 35 – Initial Reservoir Pressures; Pine River Area

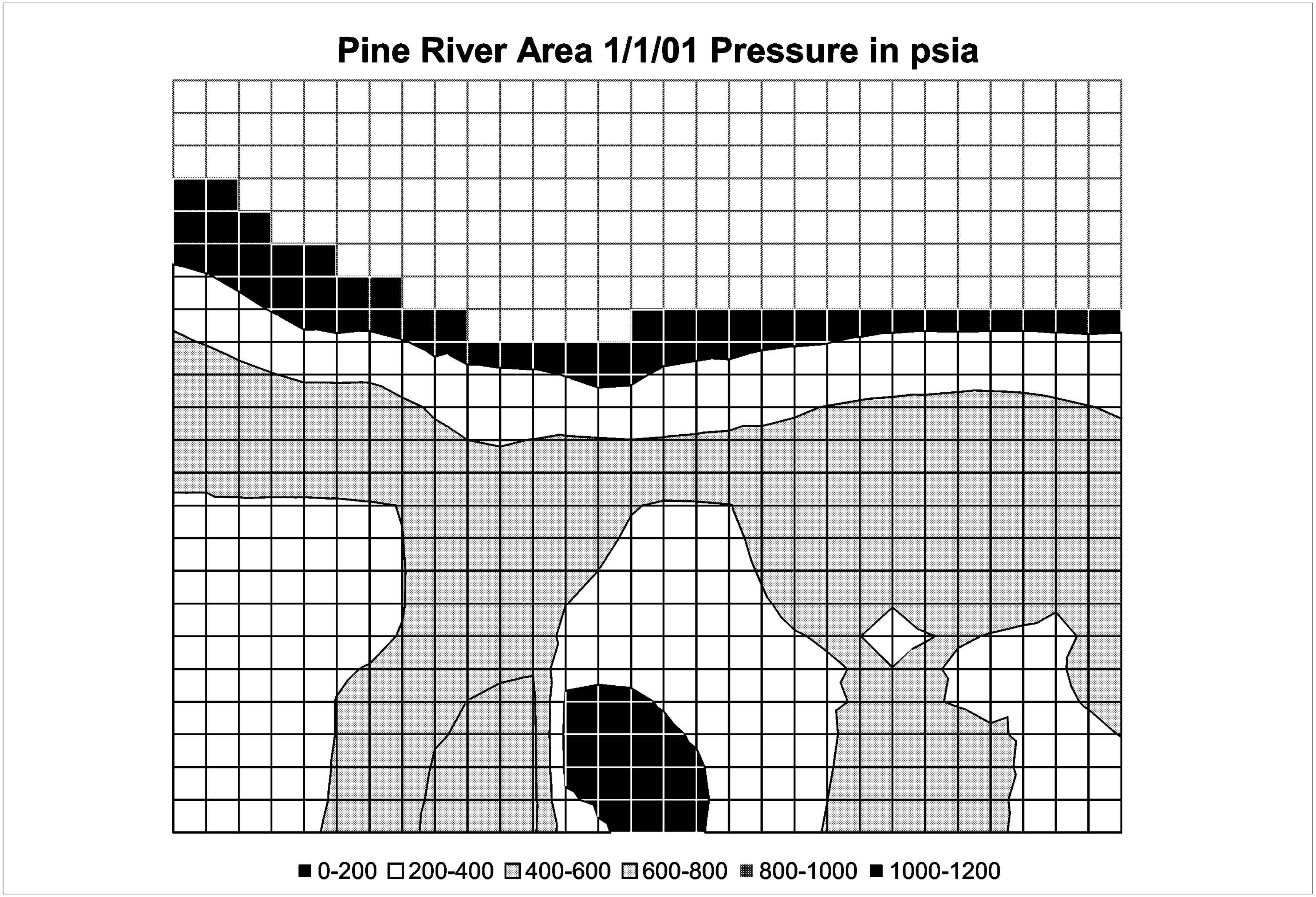


Figure 36 – Current Reservoir Pressures; Pine River Area

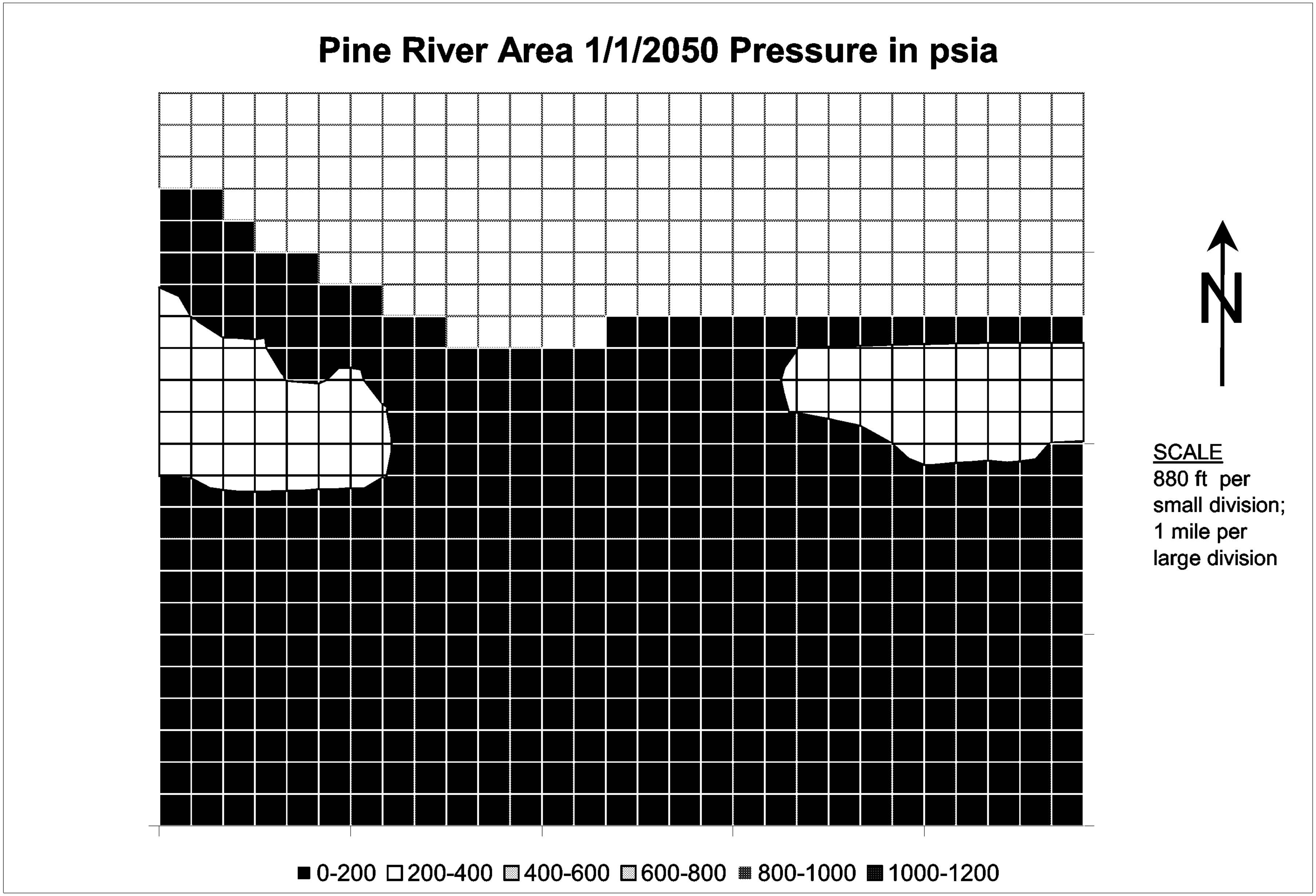


Figure 37 – Reservoir Pressures, Year 2050; Pine River Area

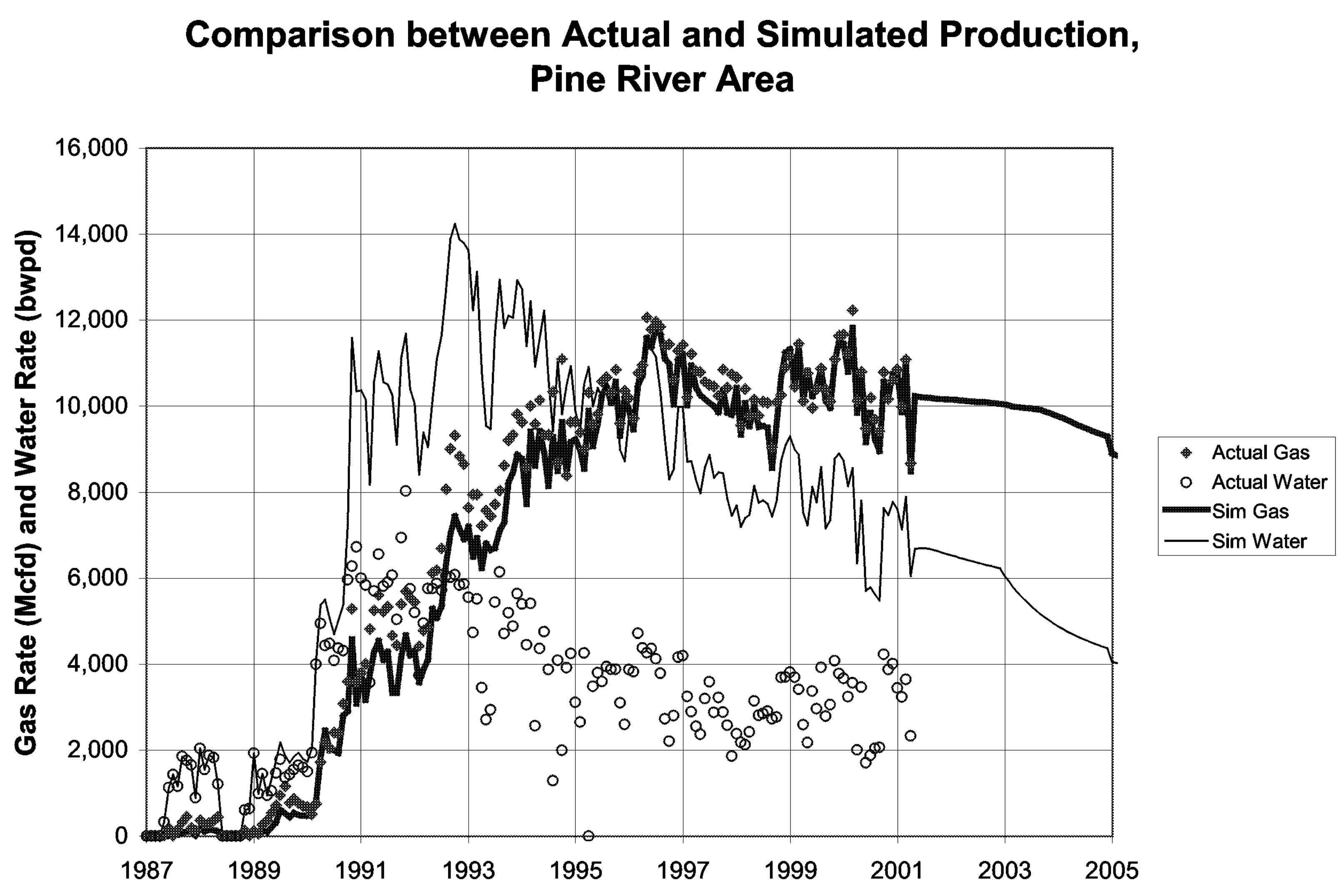


Figure 38 – Simulated vs. Actual Gas and Water Production Rates for Pine River Model

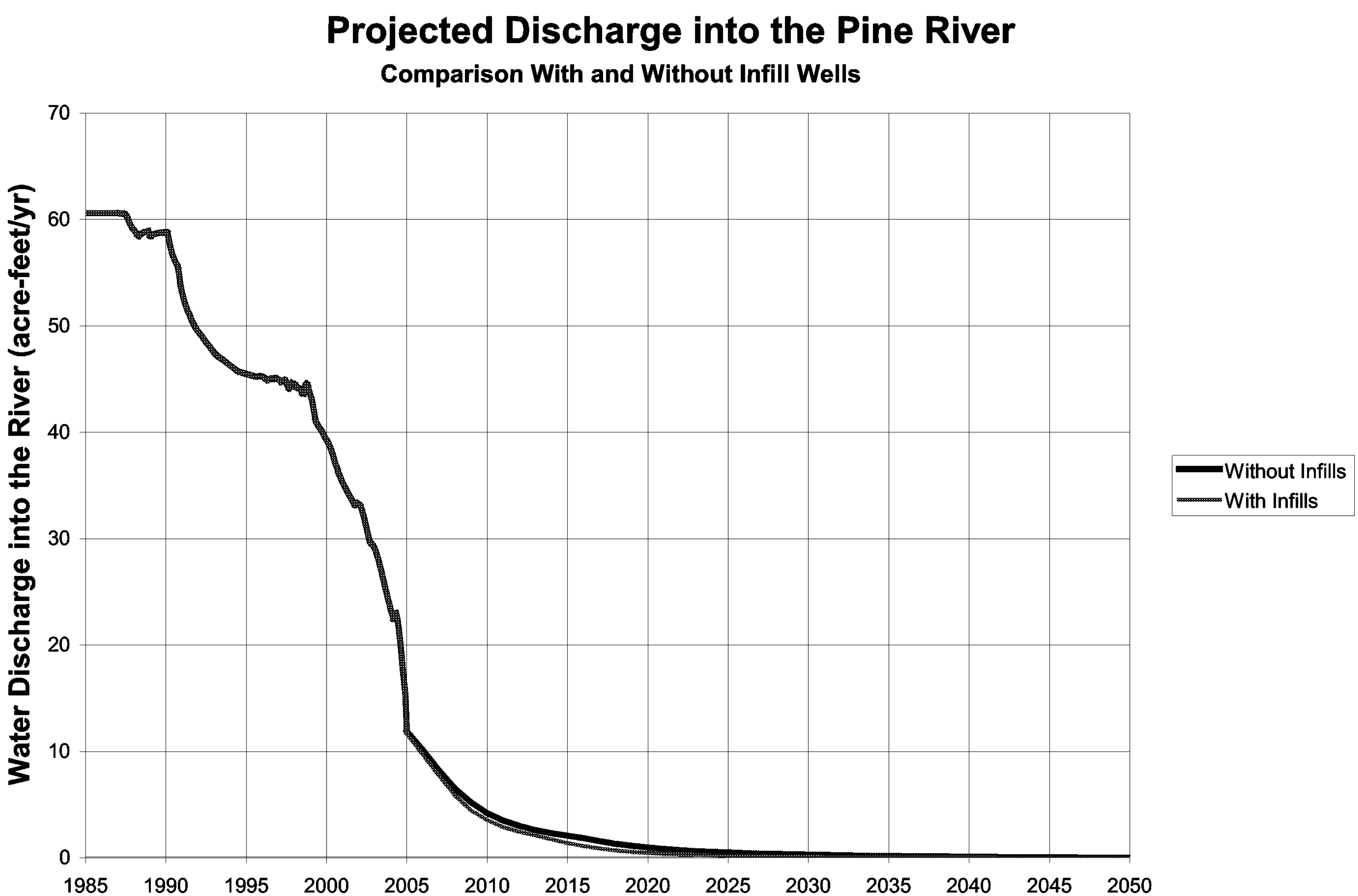


Figure 39 – Water Discharge Rates From Fruitland and Pictured Cliffs Sandstone into Pine River

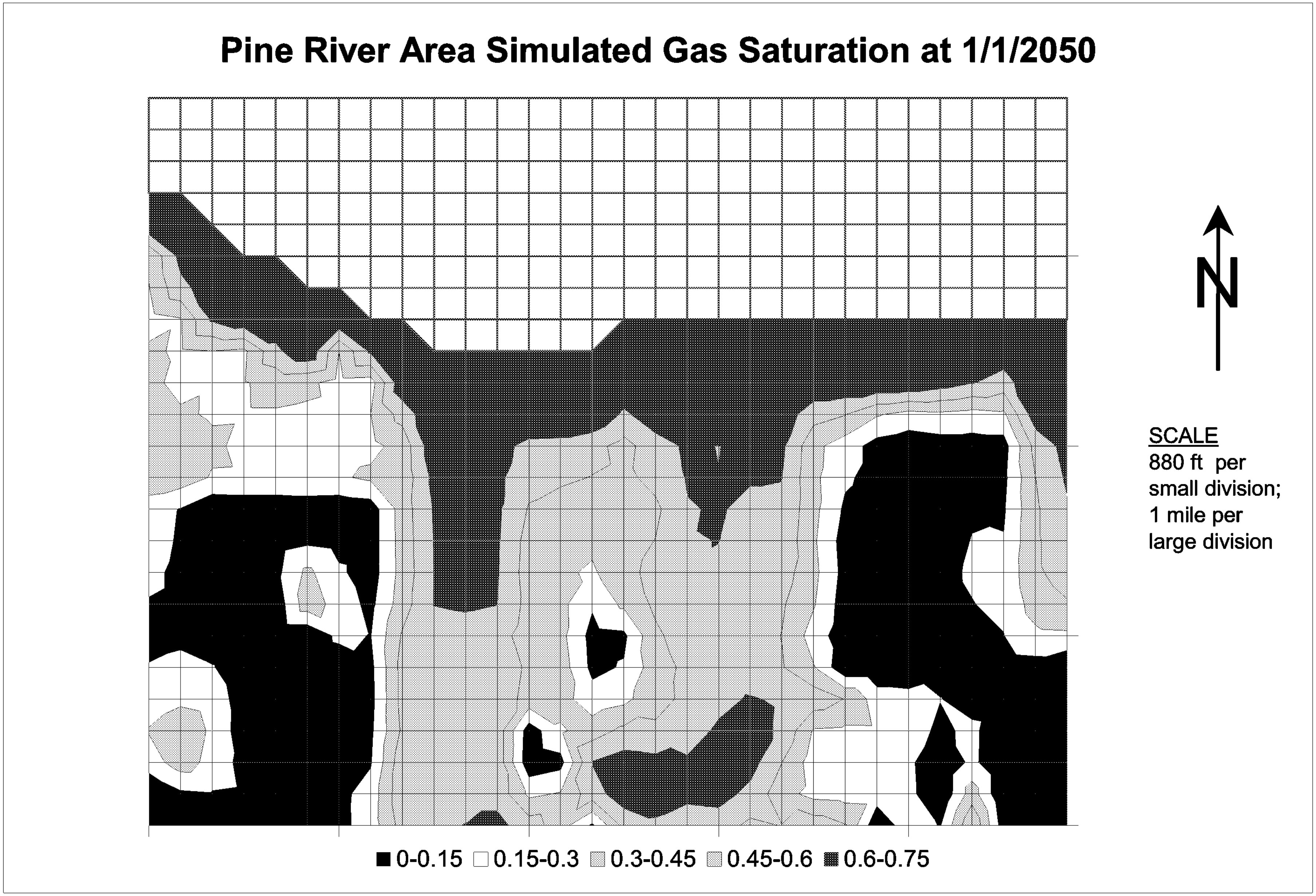


Figure 40 – Gas Saturation Fraction in Pine River at Year 2050

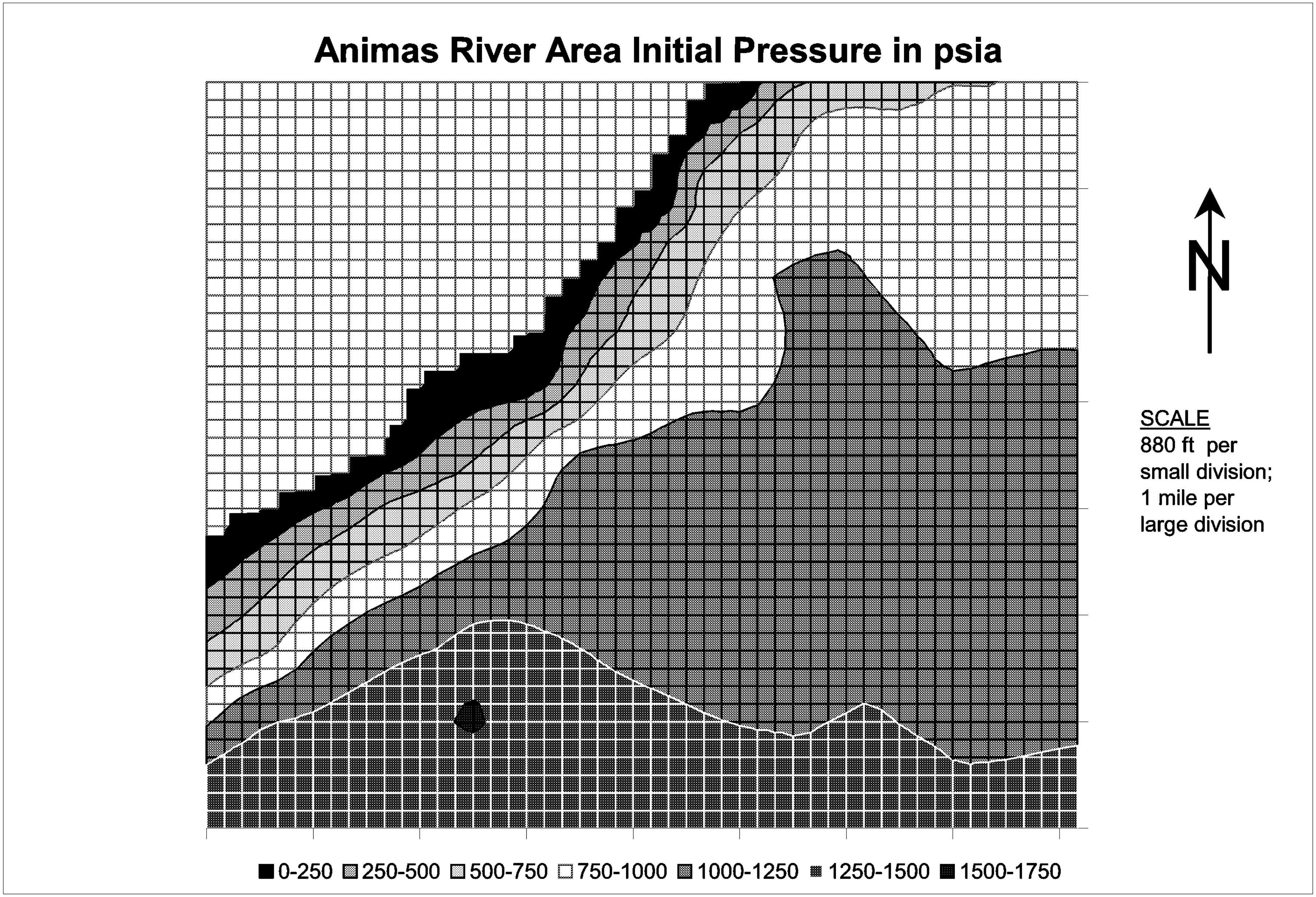


Figure 41 – Initial CBM Reservoir Pressures:
Animas River

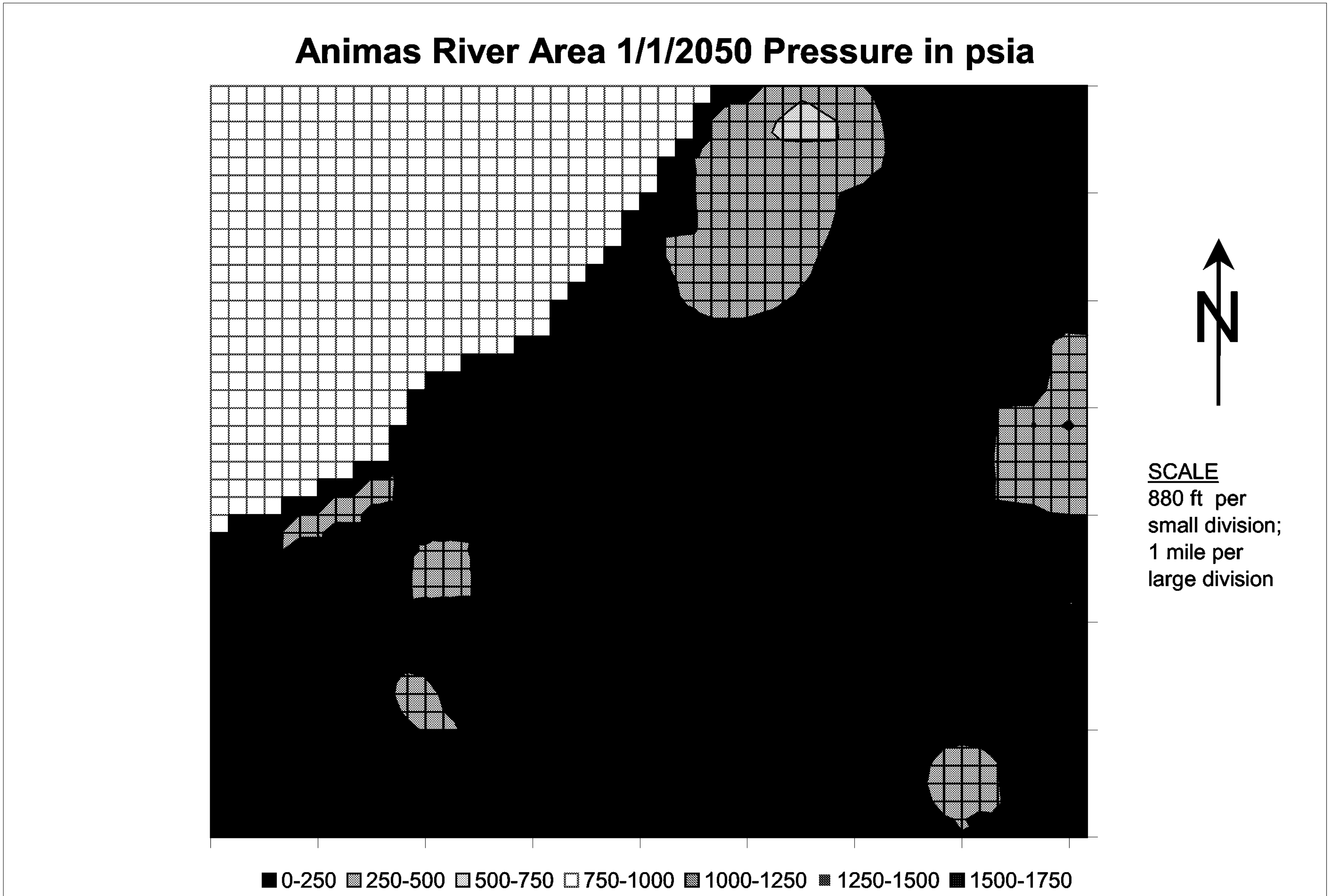


Figure 42 – Reservoir Pressures, Year 2050: Animas River

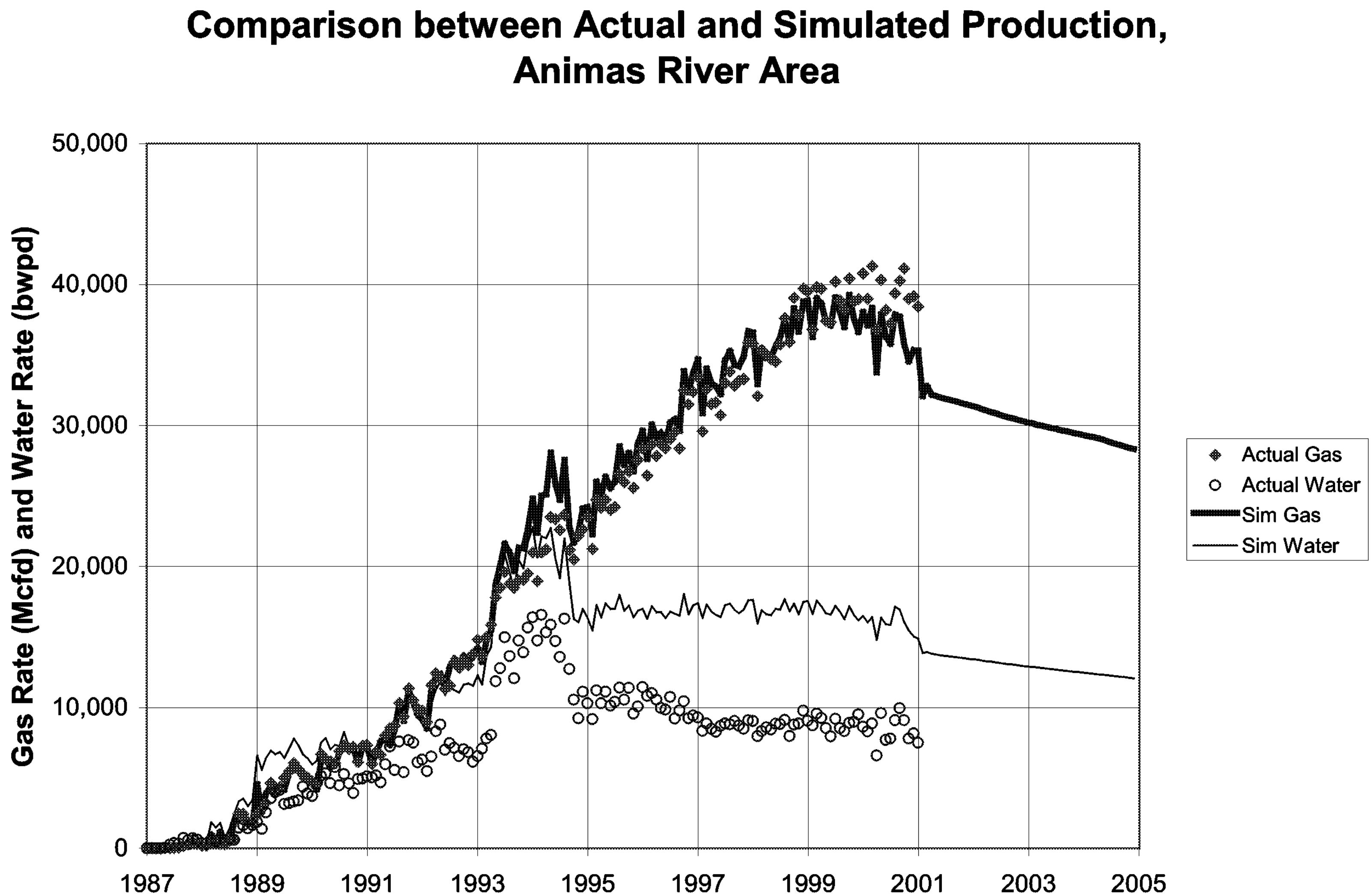


Figure 43 – Simulated vs. Actual Gas and Water Production Rates for Animas River Model

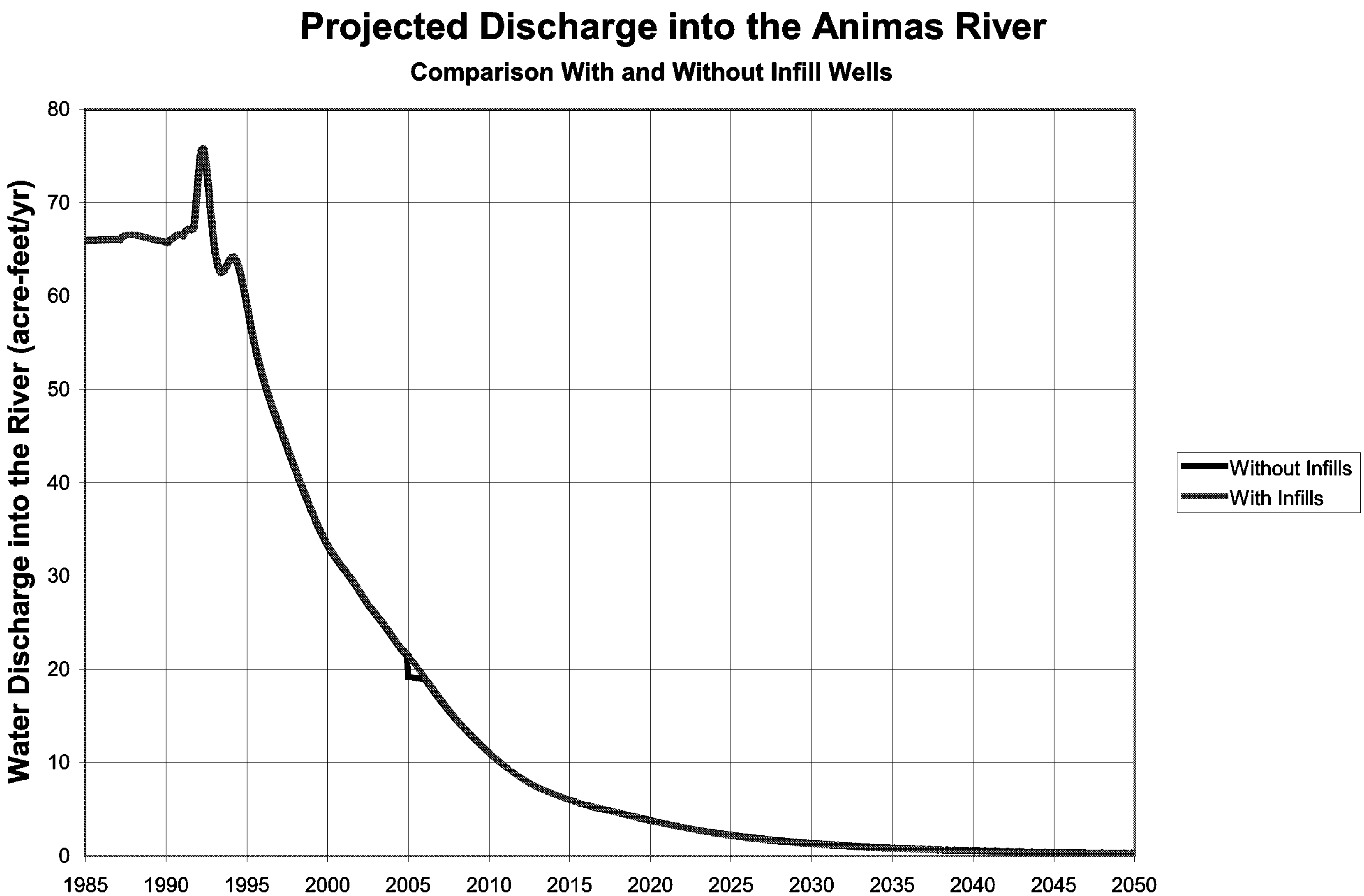


Figure 44 – Water Discharge Rates from Fruitland and Pictured Cliffs Sandstone into Animas River

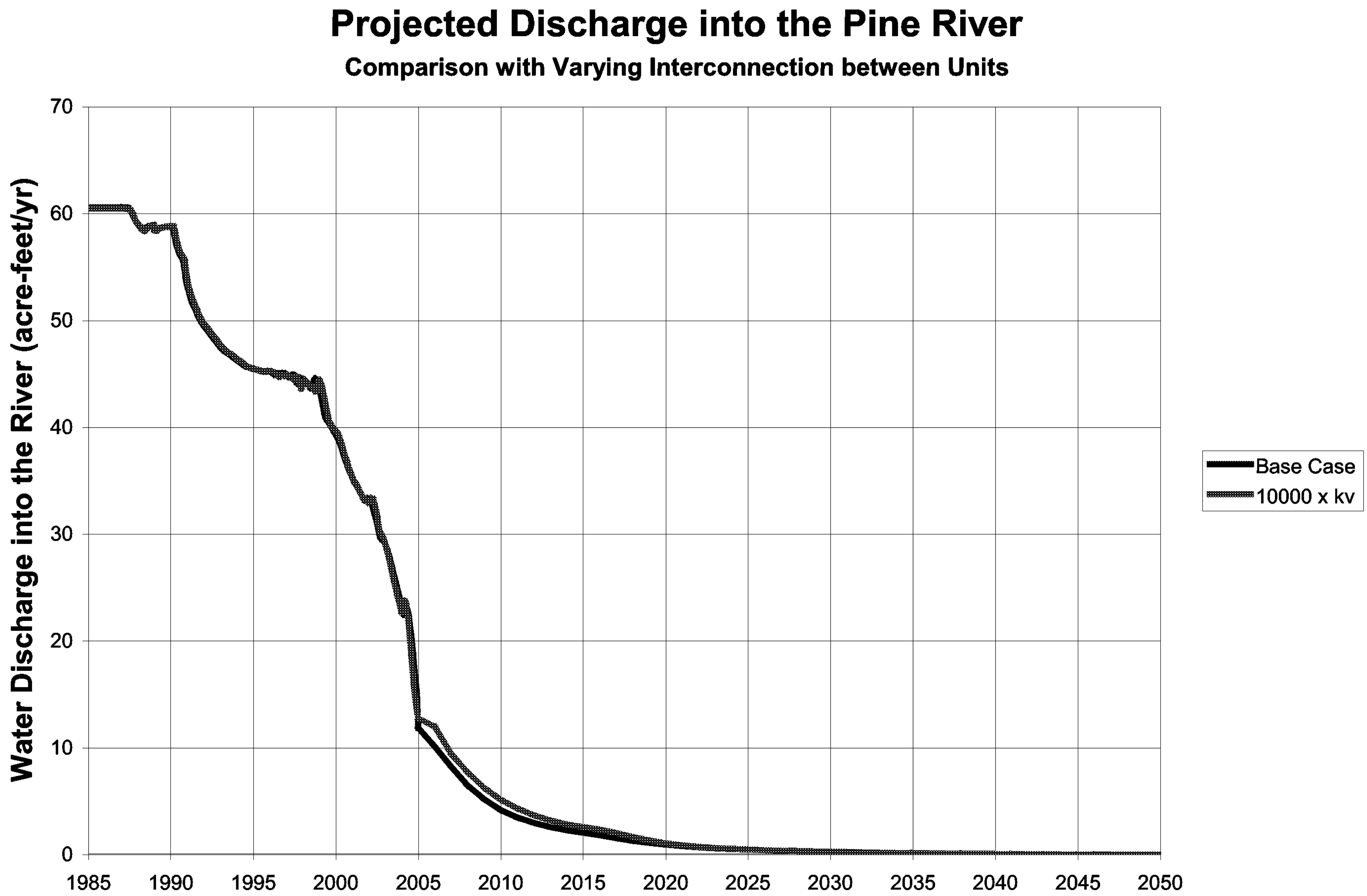


Figure 45 – Vertical Permeability
Sensitivity Case: Pine River Model

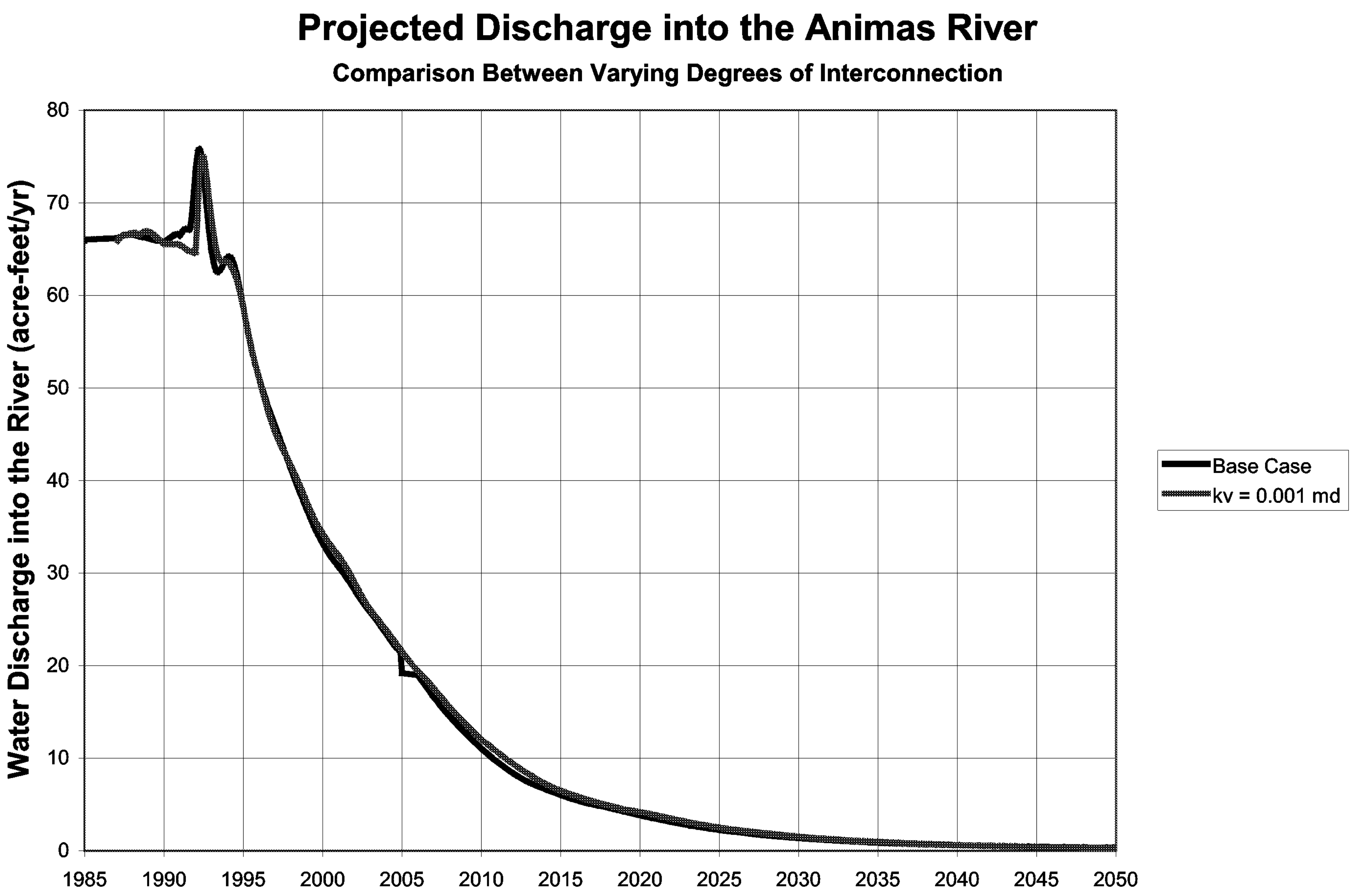


Figure 46 – Vertical Permeability Sensitivity Case: Animas River Model

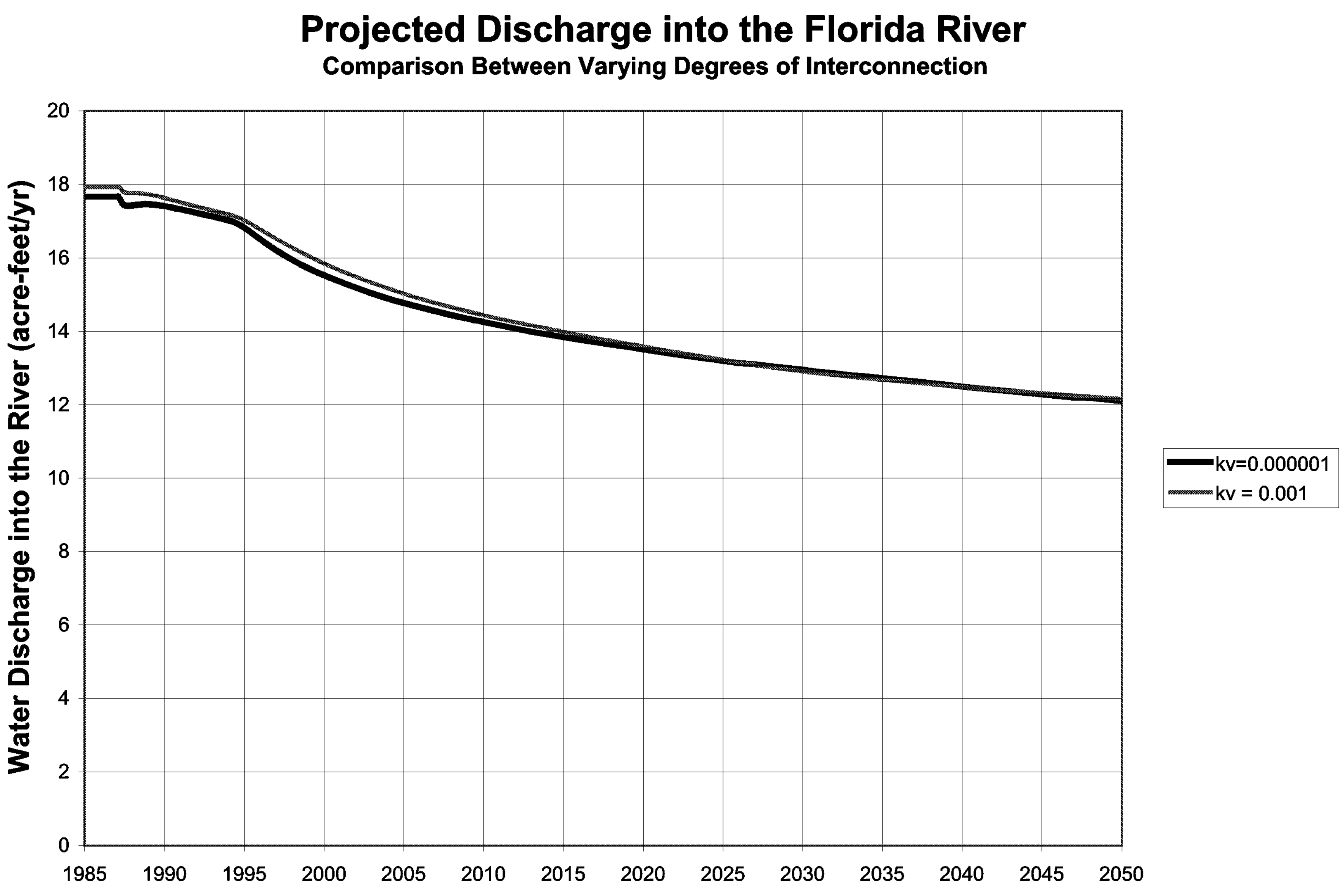


Figure 47– Vertical Permeability
Sensitivity Case: Florida River Model

Appendix A

Water Well Driller Logs
Pine River Area

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HERE-IN, TYPE OR PRINT IN BLACK INK.

COLORADO DIVISION OF WATER RESOURCES
1313 Sherman Street - Room 818
Denver, Colorado 80203

RECEIVED
JUL 0 2 1984
WATER RESOURCES
STATE ENGINEER
COLO.

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 135362

WELL OWNER Pick Bar Ranch

ADDRESS PO Box 337 Bayfield, Colo. 81122

DATE COMPLETED May 10, 1984

NE ¼ of the SW ¼ of Sec. 14
T. 35 N, R. 7 W NM P.M.

HOLE DIAMETER
9 in. from 0 to 10 ft.
7 in. from 10 to 32 ft.
in. from to ft.

WELL LOG

From	To	Type and Color of Material	Water Loc.
0	14	Brown sand, rock, gravel	
14	26	Red sand & gravel	15
26	32	gray sand & gravel	
32		gray shale	

RECEIVED
JAN 1 2 1994
Bureau of Land Management
Durango, Colorado

TOTAL DEPTH 32

Use additional pages necessary to complete log.

DRILLING METHOD Cabletool

CASING RECORD: Plain Casing
Size 7 & kind Steel from 0 to 21 ft.
Size & kind from to ft.
Size & kind from to ft.

Perforated Casing
Size 7 & kind Steel from 21 to 32 ft.
Size & kind from to ft.
Size & kind from to ft.

GROUTING RECORD
Material Cement
Intervals 0-10
Placement Method Poured

GRAVEL PACK: Size
Interval

TEST DATA
Date Tested May 10, 1984
Static Water Level Prior to Test 10 ft.
Type of Test Pump Bailed
Length of Test 4
Sustained Yield (Metered) 18
Final Pumping Water Level 20

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HERE. TYPE OR PRINT IN BLACK

COLORADO DIVISION OF WATER RESOURCES
1313 Sherman Street - Room 818
Denver, Colorado 80203

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 26533-F

JUL 13 1983
WATER RESOURCES STATE ENGINEER

E

WELL OWNER Darlene Brinley   SE ¼ of the NW ¼ of Sec. 14
ADDRESS 1013 C.R. 300 Durango, Colo 81301   T. 35 N, R. 7 W, N.M. P.M.
DATE COMPLETED June 3, 1983

WELL LOG

From	To	Type and Color of Material	Water Loc.
0	10	Brown dirt, rocks	
10	20	Brown sand, gravel	14
20	34	gray sand, gravel	
34		shale	

RECEIVED
JAN 12 1984
Bureau of Land Management
Durango, Colorado

TOTAL DEPTH 34

Use additional pages necessary to complete log.

HOLE DIAMETER
10 in. from 0 to 10 ft.
7 in. from 10 to 34 ft.
___ in. from ___ to ___ ft.

DRILLING METHOD Cabletool

CASING RECORD: Plain Casing
Size 7 & kind Steel from 0 to 24 ft.
Size ___ & kind ___ from ___ to ___ ft.
Size ___ & kind ___ from ___ to ___ ft.

Perforated Casing
Size 7 & kind Steel from 24 to 34 ft.
Size ___ & kind ___ from ___ to ___ ft.
Size ___ & kind ___ from ___ to ___ ft.

GROUTING RECORD
Material Cement
Intervals 0-10
Placement Method Poured

GRAVEL PACK: Size ___
Interval ___

TEST DATA
Date Tested June 3, 1983
Static Water Level Prior to Test 5 ft.
Type of Test Pump Bailed
Length of Test 4
Sustained Yield (Metered) 20
Final Pumping Water Level 20

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HEREON. TYPE OR PRINT IN BLACK INK.

COLORADO DIVISION OF WATER RESOURCES
300 Columbine Bldg., 1845 Sherman St.
Denver, Colorado 80203

JAN 21 1977

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 86349

WELL OWNER Mason P. Castin

ADDRESS Box 76 Bayfield Colo. 81122

DATE COMPLETED 12-02-, 1976

SE ¼ of the NE ¼ of Sec. 14

T. 35 N, R. 7 W, NM P.M.

WELL LOG

From	To	Type and Color of Material	Water Loc.
0	37	Clay	
37	64	Boulders	132
64	148	shale	

RECEIVED
JAN 1 2 1984
Bureau of Land Management
Durango, Colorado

TOTAL DEPTH 148

Use additional pages necessary to complete log.

HOLE DIAMETER

8 in. from 0 to 64 ft.

7⅞ in. from 64 to 148 ft.

____ in. from ____ to ____ ft.

DRILLING METHOD Rotary air & Cable Tool

CASING RECORD: Plain Casing

Size 5" & kind P.V.C from 0 to 120 ft.

Size 5" & kind P.V.C from 140 to 148 ft.

Size ____ & kind ____ from ____ to ____ ft.

Perforated Casing

Size 5" & kind P.V.C from 120 to 140 ft.

Size ____ & kind ____ from ____ to ____ ft.

Size ____ & kind ____ from ____ to ____ ft.

GROUTING RECORD

Material Cement & Sand

Intervals 0-15'

Placement Method Shovel

GRAVEL PACK: Size Chips

Interval 15-148

TEST DATA

Date Tested 12-2-, 197

Static Water Level Prior to Test 60

Type of Test Pump Bail & Air

Length of Test One hour

Sustained Yield (Metered) 7 gal. min.

Final Pumping Water Level ____

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HERE. O... E OR PRINT IN BLACK I...

COLORADO DIVISION OF WATER RESOURCES
300 Columbine Bldg., 1845 Sherman St.
Denver, Colorado 80203

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 102918

RECEIVED
NOV 13 1978
WATER RESOURCES
STATE ENGINEER
COLO.

WELL OWNER Harve T. Peterson

ADDRESS PO Box 222 Igo Colo

DATE COMPLETED Nov 1, 1978

SW ¼ of the NW ¼ of Sec. 14

T. 35 N., R. 7 W., NM P.M.

HOLE DIAMETER

6 in. from 1 to 125 ft.

____ in. from ____ to ____ ft.

____ in. from ____ to ____ ft.

DRILLING METHOD Rotary

CASING RECORD: Plain Casing

Size 6" & kind steel from 1 to 25 ft.

Size ____ & kind ____ from ____ to ____ ft.

Size ____ & kind ____ from ____ to ____ ft.

Perforated Casing

Size ____ & kind ____ from ____ to ____ ft.

Size ____ & kind ____ from ____ to ____ ft.

Size ____ & kind ____ from ____ to ____ ft.

GROUTING RECORD

Material Neat Cement

Intervals 10' below

Placement Method ——

GRAVEL PACK: Size ——

Interval ____

TEST DATA

Date Tested Nov 1, 1978

Static Water Level Prior to Test 60' ft.

Type of Test Pump LMR

Length of Test Air Lift

Sustained Yield (Metered) 2gal/min

Final Pumping Water Level ——

WELL LOG

From	To	Type and Color of Material	Water Loc.
1'	20'	Gravel Top Soil	
20'	80'	Shale	
80'	82'	coal	80'
82'	125'	Shale, Sandstone	

RECEIVED
JAN 12 1994
Bureau of Land Management
Durango, Colorado

TOTAL DEPTH 125'

Use additional pages necessary to complete log.

WELL CONSTRUCTION AND TEST REPORT

1. STATE OF COLORADO, OFFICE OF THE STATE ENGINEER

For Office Use Only

RECEIVED DEC 21 '92

RECEIVED JAN 12 1994 WATER RESOURCES STATE ENGINEER COLO.

Bureau of Land Management Durango, Colorado

WELL PERMIT NUMBER 157425

2. OWNER NAME(S) O. D. Perry
Mailing Address 70 Cedar Dr. [illegible]
City, St. Zip Durango, CO 81301
Phone ( )

3. WELL LOCATION AS DRILLED: SE 1/4 NW 1/4, Sec. 14 Twp. 35 N, Range 7W NMPM
DISTANCES FROM SEC. LINES:
1930 ft. from N (north or south) Sec. line, and 2290 ft. from W (east or west) Sec. line, OR
SUBDIVISION: River Reaches #2 LOT 83 BLOCK ___ FILING(UNIT) ___
STREET ADDRESS AT WELL LOCATION:

4. GROUND SURFACE ELEVATION ___ ft. DRILLING METHOD air rotary
DATE COMPLETED 12/27/90, TOTAL DEPTH 46' ft. DEPTH COMPLETED 46' ft.

5. GEOLOGIC LOG:

Depth	Description of Material (Type, Size, Color, Water Location)
0-3	soil
3-28	gravel
28-46	shale
	H_2O @ 31'

6. HOLE DIAM. (in.)

HOLE DIAM. (in.)	From (ft)	To (ft)
10	0	20
7	20	28
6 1/4	28	46

7. PLAIN CASING

OD (in)	Kind	Wall Size	From(ft)	To(ft)
7	steel	3/8	0	20
4 1/2	pvc	sch 40	20	28

PERF. CASING: Screen Slot Size: .010

OD (in)	Kind	Wall Size	From(ft)	To(ft)
4 1/2	pvc	sch 40	28	46

8. FILTER PACK:
Material none
Size
Interval

9. PACKER PLACEMENT:
Type
Depth

10. GROUTING RECORD:

Material	Amount	Density	Interval	Placement
Cement	15 sks	12.5 #	0-20	poured

REMARKS:

11. DISINFECTION: Type HTH Amt. Used 6 oz

12. WELL TEST DATA: ☐ Check box if Test Data is submitted on Supplemental Form.
TESTING METHOD air lift
Static Level 12' ft. Date/Time measured 12/27/90, Production Rate 20 gpm.
Pumping level 18' ft. Date/Time measured 12/27/90, Test length (hrs.) 1 hr
Remarks

13. I have read the statements made herein and know the contents thereof, and that they are true to my knowledge. [Pursuant to Section 24-4-104 (13)(a) C.R.S., the making of false statements herein constitutes perjury in the second degree and is punishable as a class 1 misdemeanor.]
CONTRACTOR BEEMAN BROS. DRILLING 31502 Hiway 160
Mailing Address DURANGO, COLO. 81301 Phone (303) 259 1195 Lic. No. 871
Name/Title (Please type or print) J L BEEMAN, PRES
Signature [illegible]
Date

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HERE. TYPE OR PRINT IN BLACK

COLORADO DIVISION OF WATER RESOURCES
1313 Sherman Street - Room 818
Denver, Colorado 80203

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 035551-F

WELL OWNER R.B. Billings

ADDRESS 144 Ponderosa Dr.
Bayfield, CO 81122

DATE COMPLETED 9-18, 1989

SE ¼ of the NW ¼ of Sec. 14

T. 35 N, R. 7 W, N.M. P.M.

WELL LOG

From	To	Type and Color of Material	Water Loc.
0	42	sand and gravel	

TOTAL DEPTH 42'

Use additional pages necessary to complete log.

HOLE DIAMETER

6¾" in. from 0 to 42 ft.

in. from to ft.

in. from to ft.

DRILLING METHOD air rotary

CASING RECORD: Plain Casing

Size 7" & kind steel from 0 to 25 ft.

Size & kind from to ft.

Size & kind from to ft.

Perforated Casing

Size 7" & kind steel from 25 to 33 ft.

Size & kind from to ft.

Size & kind from to ft.

GROUTING RECORD

Material cement

Intervals 0-20'

Placement Method and

GRAVEL PACK: Size none

Interval

TEST DATA

Date Tested 9-18-, 1989

Static Water Level Prior to Test 7' ft.

Type of Test Pump air lift

Length of Test 1 r.

Sustained Yield (Metered) 20 gpm

Final Pumping Water Level not known

THIS FORM MUST BE SUBMITTED WITHIN 60 DAYS OF COMPLETION OF THE WORK DESCRIBED HERE-ON. TYPE OR PRINT IN BLACK INK.

COLORADO DIVISION OF WATER RESOURCES
1313 Sherman Street - Room 818
Denver, Colorado 80203

WELL COMPLETION AND PUMP INSTALLATION REPORT

PERMIT NUMBER 154238

JAN 5 '90
WATER RESOURCES
STATE ENGINEER
COLO.

WELL OWNER Thomas A. Morgan

ADDRESS 2414 Co. Rd. 505 Bayfield Colo 81122

DATE COMPLETED 7-11, 19 89

SE ¼ of the SW ¼ of Sec. 14

T. 35 N., R. 7 W, NM P.M.

WELL LOG

From	To	Type and Color of Material	Water Loc.
0	32	overburden	
32	168	Shale & Sandstone	142

RECEIVED
JAN 1 2 1994
Bureau of Land Management
Durango, Colorado

TOTAL DEPTH 168

Use additional pages necessary to complete log.

HOLE DIAMETER

8 5/8 in. from 0 to 32 ft.

7 7/8 in. from 32 to 168 ft.

in. from ___ to ___ ft.

DRILLING METHOD Cable tool Rotary air

CASING RECORD: Plain Casing

Size 5 & kind Steel from 0 to 20 ft.

Size 5 & kind P.V.C. from 20 to 140 ft.

Size ___ & kind ___ from ___ to ___ ft.

Perforated Casing

Size 5 & kind P.V.C. from 140 to 168 ft.

Size ___ & kind ___ from ___ to ___ ft.

Size ___ & kind ___ from ___ to ___ ft.

GROUTING RECORD

Material Cement

Intervals 6-15

Placement Method Shovel

GRAVEL PACK: Size Pea gravel

Interval 15'-168'

TEST DATA

Date Tested 7-11, 1989

Static Water Level Prior to Test 35 ft.

Type of Test Pump Bail & Air

Length of Test 1 hour

Sustained Yield (Metered) 60 g.P.M.

Final Pumping Water Level ———

1. WELL PERMIT NUMBER 161011

RECEIVED

JAN 1 2 1994

Bureau of Land Management
Durango, Colorado

2. OWNER NAME(S) M Yolanda Avalos
[redacted]ing Address P.O. Box 860
[redacted], St. Zip Bayfield Co 81122
Phone ( )

3. WELL LOCATION AS DRILLED: NE 1/4 NW 1/4, Sec. 14 Twp. 35 N, Range 7 W N PM
DISTANCES FROM SEC. LINES:
300 ft. from North (north or south) Sec. line, and 2070 ft. from West (east or west) Sec. line. OR
SUBDIVISION: Pine River Ranches LOT ___ BLOCK ___ FILING(UNIT) ___
STREET ADDRESS AT WELL LOCATION:

4. GROUND SURFACE ELEVATION 6800 ft. DRILLING METHOD Cable Tool
DATE COMPLETED 9-25-91. TOTAL DEPTH 35 ft. DEPTH COMPLETED 35 ft.

5. GEOLOGIC LOG:

Depth	Description of Material (Type, Size, Color, Water Location)
1-4	topsoil
4-25	Large rocks and sands
25-35	gravel + sands
	Water Location 12'

[redacted]

6. HOLE DIAM. (in.)

HOLE DIAM. (in.)	From (ft)	To (ft)
9 5/8	0	15
7"	15	35'

7. PLAIN CASING

OD (in)	Kind	Wall Size	From(ft)	To(ft)
7	Steel	.375	0	25

PERF. CASING: Screen Slot Size: .060

OD (in)	Kind	Wall Size	From(ft)	To(ft)
7	Steel	.375	25	35

8. FILTER PACK:
Material ___
Size ___
Interval ___

9. PACKER PLACEMENT:
Type ___
Depth ___

10. GROUTING RECORD:

Material	Amount	Density	Interval	Placement
neat cement	4 bags	6 gal	5-15'	Pumped

REMARKS:

11. DISINFECTION: Type Liquid bleach Amt. Used 1 gal.

12. WELL TEST DATA: ☐ Check box if Test Data is submitted on Supplemental Form.
TESTING METHOD Bailing
Static Level 6 ft. Date/Time measured 9-25-91 9: Am, Production Rate 30 gpm.
Pumping level 10 ft. Date/Time measured 9-25-91 11: Am, Test length (hrs.) 2 hrs
Remarks

13. I have read the statements made herein and know the contents thereof, and that they are true to my knowledge. [Pursuant to Section 24-4-104 (13)(a) C.R.S., the making of false statements herein constitutes perjury in the second degree and is punishable as a class 1 misdemeanor.]
[redacted]TRACTOR Hull Drilling Phone (303) 884-9686 Lic. No. 655
[redacted]g Address

Name/Title (Please type or print)	Signature	Date
[illegible]	[illegible]	10-10-91

Appendix B

Piedra River Geologic/Hydrogeologic Investigation Results

Introduction

The following is a description of sections measured in the Fruitland Formation for the San Juan Basin study. One section was measured in the Pargin Mountain Quadrangle and the other two were measured in the Chimney Rock Quadrangle. Franklin Dorin and Christie Vliss measured all sections during the period of August 7, 2001 to August 14, 2001, under the supervision of Dr. Gary Gianniny at Fort Lewis College.

Methods

The Highway 160 Section was measured using a Brunton compass and a Jacob's Staff. It should be noted that the upper 10 meters of the outcrop was recorded from the road using binoculars. This was done for safety purposes.

The Sy 2a Section was measured using the same equipment as that of the previous section. An offset was performed in order to achieve a better description of the unit.

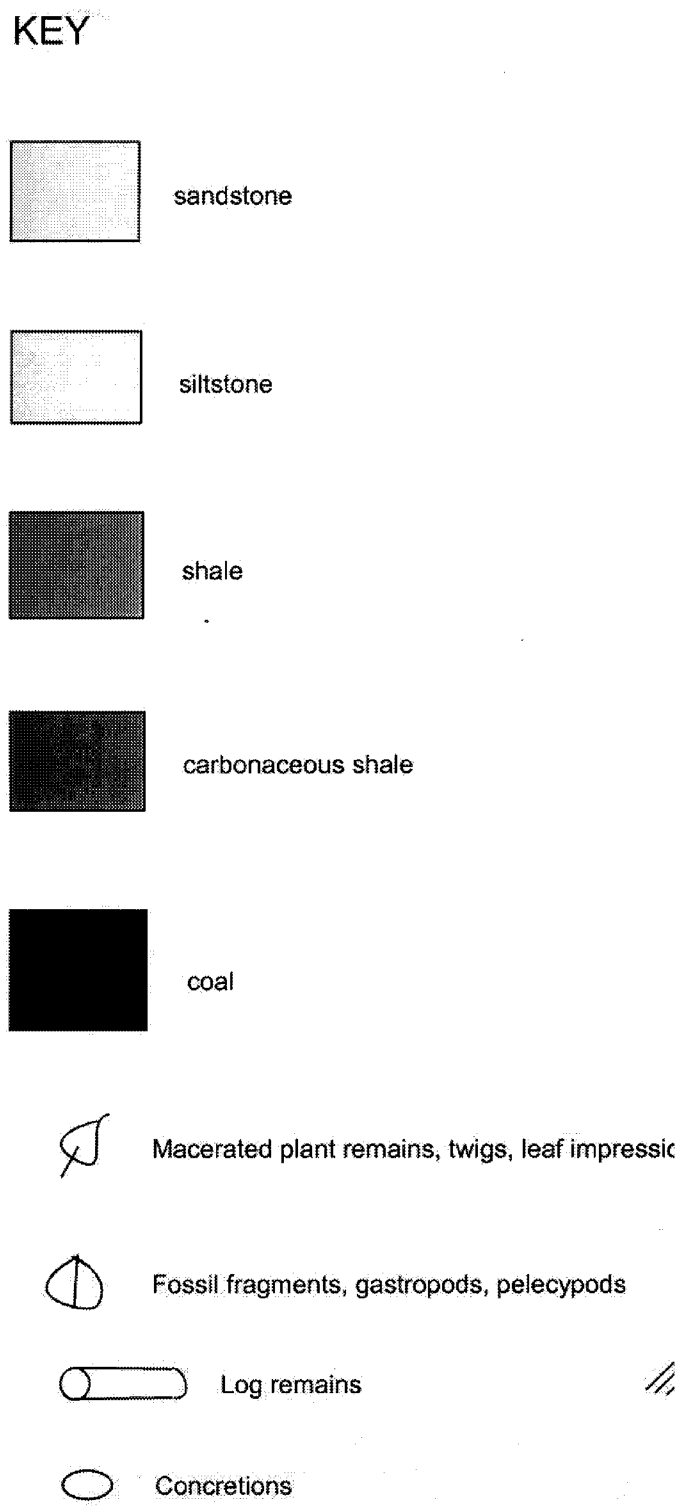
The Sy 2b1-2 Section was also measured in the same manner. Due to the location of the beginning of the section, that of the valley floor, Quaternary alluvial deposits covered much of the section.

The Sy 2b3-4 Section was done using a Brunton compass and a metered tape measure. This method was chosen over the previous method in order to utilize better exposures of the outcrop. The tape measurer was extended for a noted distance and its bearing and angle from horizontal were recorded. The line of measurement was then described. This procedure was repeated until the section was completed. Calculations included in this report illustrate the means by which true thickness was then determined.

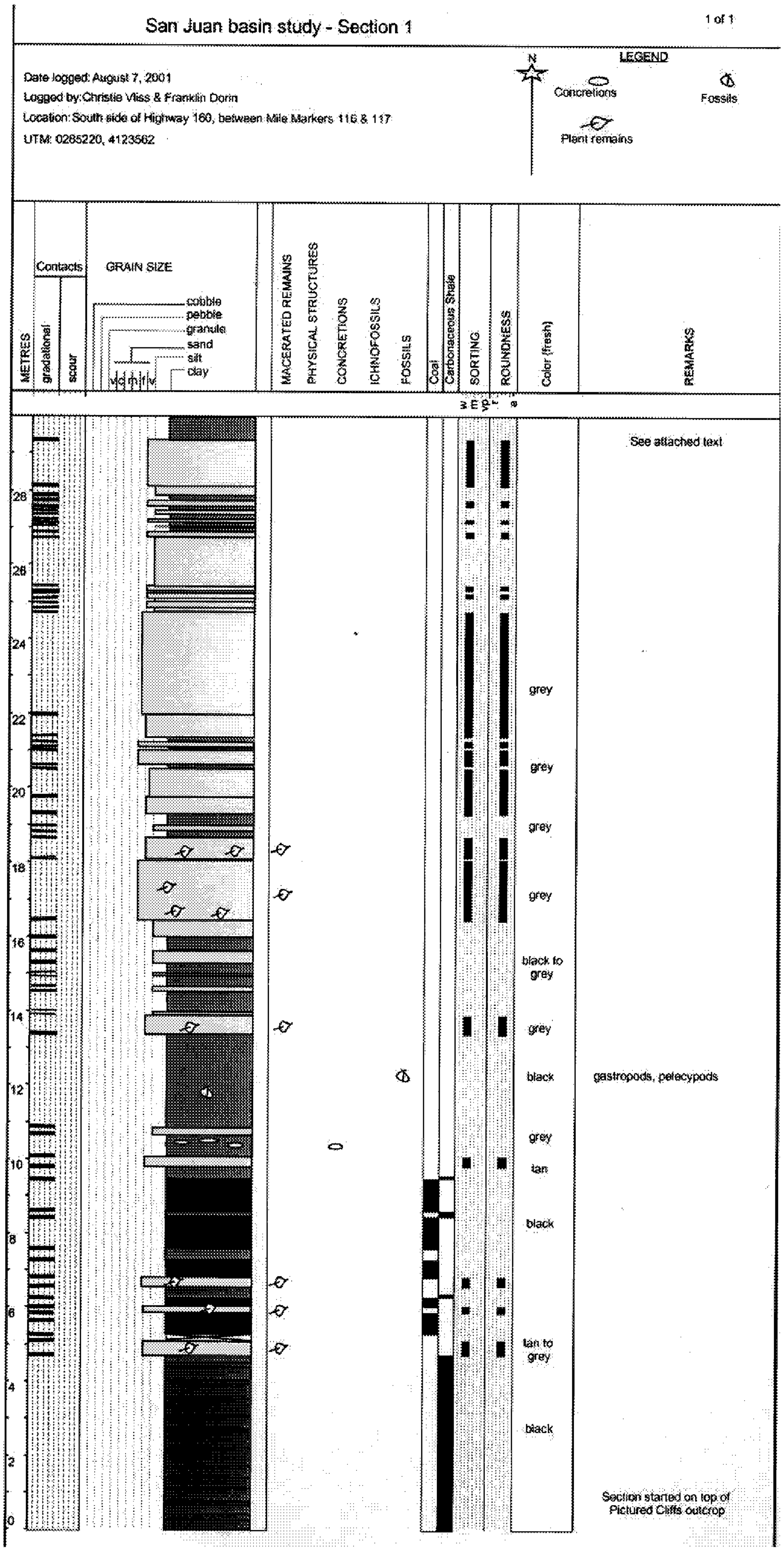
The Heath's Haven 1-4 Section was measured using a Brunton compass and a Jacob's Staff.

It should be noted that some portions of sections were initially covered and that wherever possible, a line was trenched in order to obtain a better description of the measured unit.

Section	T	R	S	UTM	Total height measured
1	T34N	R5W	9	285220, 4123562	30 m
2	T34N	R5W	13U	292434, 4118124	125 m
3	T34N	R4W	29	295180, 4115373	110 m



Key top Stratigraphic Nomenclature



Section 1: Highway 160

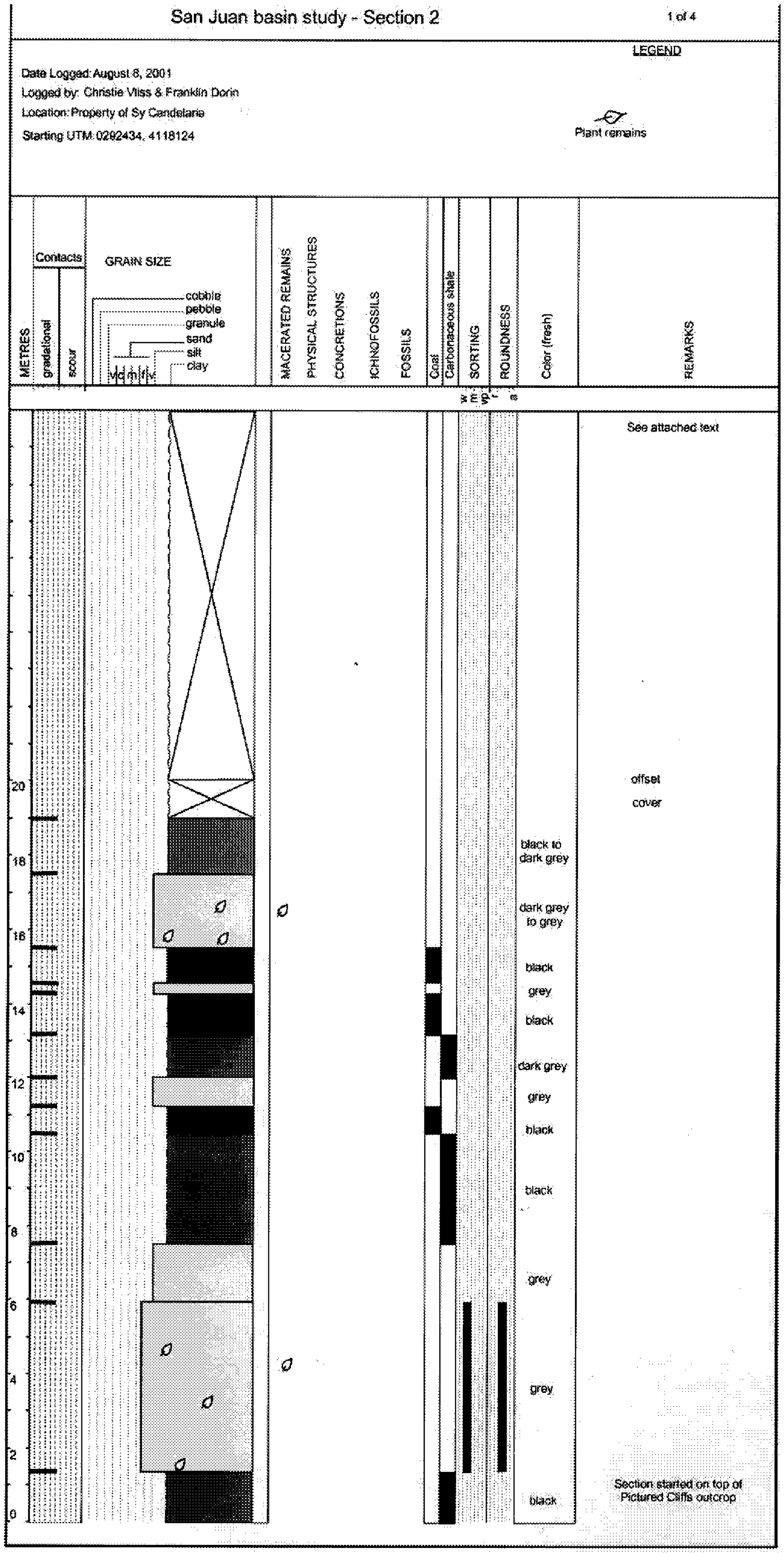
Section 1

Location: Pargin Mountain Quadrangle
Highway 160 between Mile Markers 116 & 117
Outcrop exposure on south side of highway
Utility pole on top of exposure
T34N R5W S9
UTM 285220, 4123562

Meter	**Description**
28.75-30.0	black shale, possibly carbonaceous
27.25-28.75	sandstone with 5-20cm beds, mud rip-ups at base of unit, upper and lower contacts gradational, weathered color tan to orange
25.75-27.25	interbedded sandstone, siltstone, and shale; weathered color of sandstone is orange
24.50-25.75	grey siltstone, some orange staining, upper and lower contacts gradational
23.75-24.50	interbedded siltstones and sandstones; siltstones have reddish, oxidized staining, upper and lower contacts gradational
21.00-23.75	weathered tan to orange sandstone, faint cross-bedding, beds appear to be up to 20cm thick, mud rip-ups visible at base of some beds, upper and lower contacts gradational
19.50-21.0	interbedded sandstones and shales, sandstones; rip-ups at bases, contacts gradational
*****	This portion of the section was estimated and described using binoculars, standing on roadside of Highway 160.
18.40-19.50	grey sandstone, FUS, fine lower grains at base, very fine lower grains at top, large amounts of mud/clay, no visible bedding
17.70-18.40	interbedded shale and siltstone; shale is black to dark grey, fissile; siltstone is grey, hackly, very friable, contains muscovite
15.50-17.70	sandstone, fresh color grey, weathered color tan to orange, fine upper grains, sub angular to sub rounded grains, moderate sorting, faint trough cross bedding, beds 5-20cm thick, mud rip-ups and large amounts of macerated plant remains at base, thereafter macerated

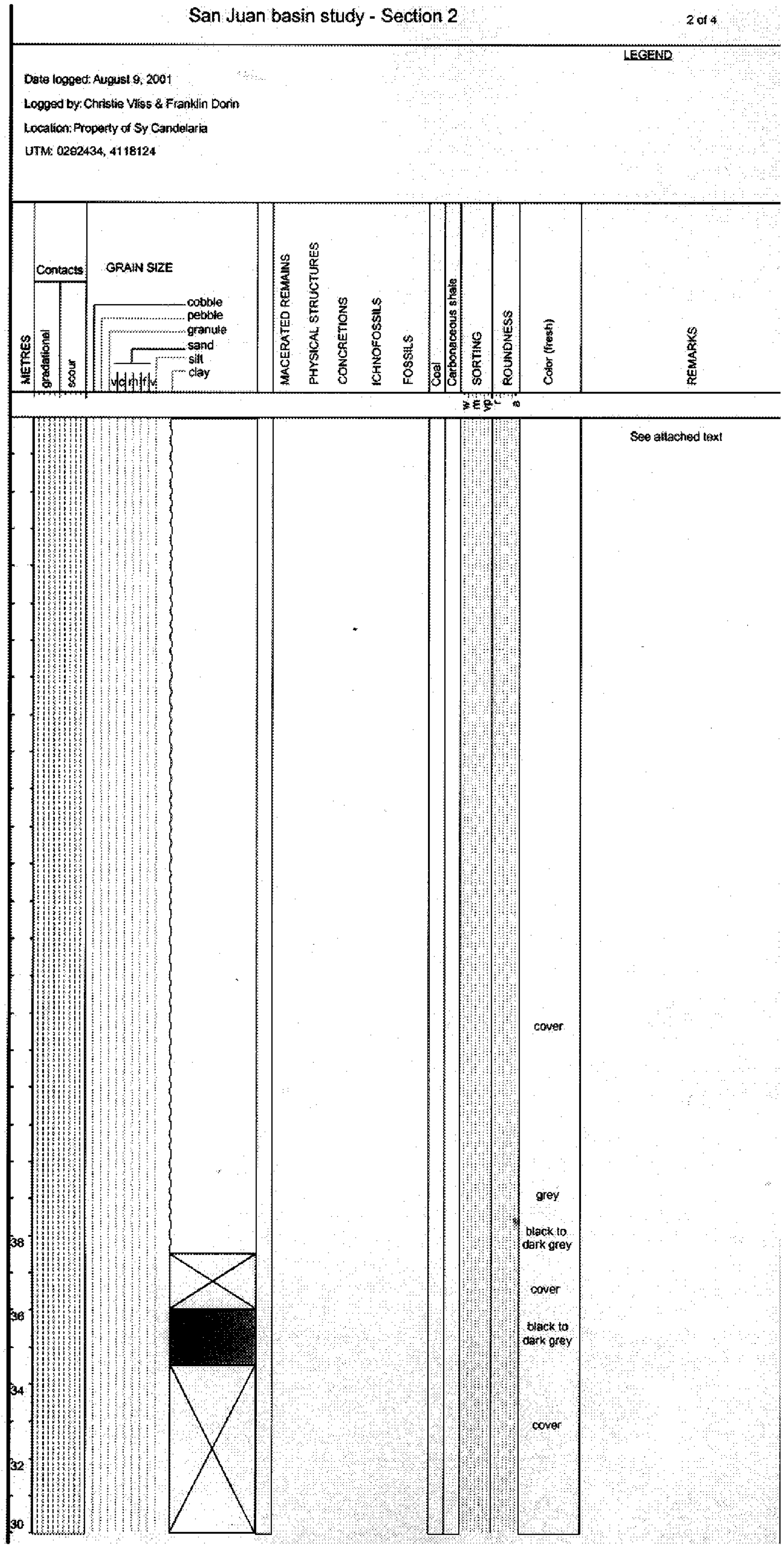
	plant remains confined to bedding planes, thin recessive mud layer near top, lateral variation in thickness, thickens to the northeast
12.90-15.50	interbedded shales and siltstones; shales black to grey, fissile, lack of fossil fragments; siltstones grey, hackly; gradational upper and lower contacts
12.30-12.90	sandstone, fine upper-medium lower grains, moderate sorting, sub angular to sub rounded grains, clay rip-ups and large amounts of macerated plant remains at base; thereafter macerated plant remains confined to bedding planes
9.75-12.30	black shale, fissile, highly fossiliferous near base, pelecypods, gastropods, becoming less fossiliferous near top, iron staining
9.50-9.75	grey siltstone, hackly, yellow-brown staining
9.00-9.50	black shale, fissile with 5-8cm thick layer of well cemented iron colored concretions; siltstone weathers deep red to white color, slightly calcareous, contains macerated plant remains
8.75-9.0	interbedded very fine lower sandstone, hackly siltstone, fissile shale, gradational contacts
5.80-8.75	interbedded black, fissile shale, carbonaceous shale and coal; shale and coal have yellow staining, coal slightly vitreous, contains some silt; contacts gradational
5.50-5.80	interbedded very fine lower sand and shale; sand weathers tan to orange color
5.20-5.50	black, fissile shale, slightly calcareous at base
5.00-5.20	coal, slightly vitreous, contains some silt
4.70-5.0	very fine lower sandstone, thin laminations, coal stringers, macerated plant remains, weathers tan to orange color, gradational contacts
4.30-4.70	coal, slightly vitreous, contains some silt
4.10-4.30	cover
3.80-4.10	very fine lower grained sandstone, sub angular to sub rounded grains, moderate sorting, thin laminations, coal stringers; lower portion of bed contains macerated plant

	remains; sandstone contains quartz, black accessory mineral, cloudy grains; gradational contacts
. **0-3.80**	black fissile, carbonaceous shale with coal beds 1-10cm thick; coal contains minor silt

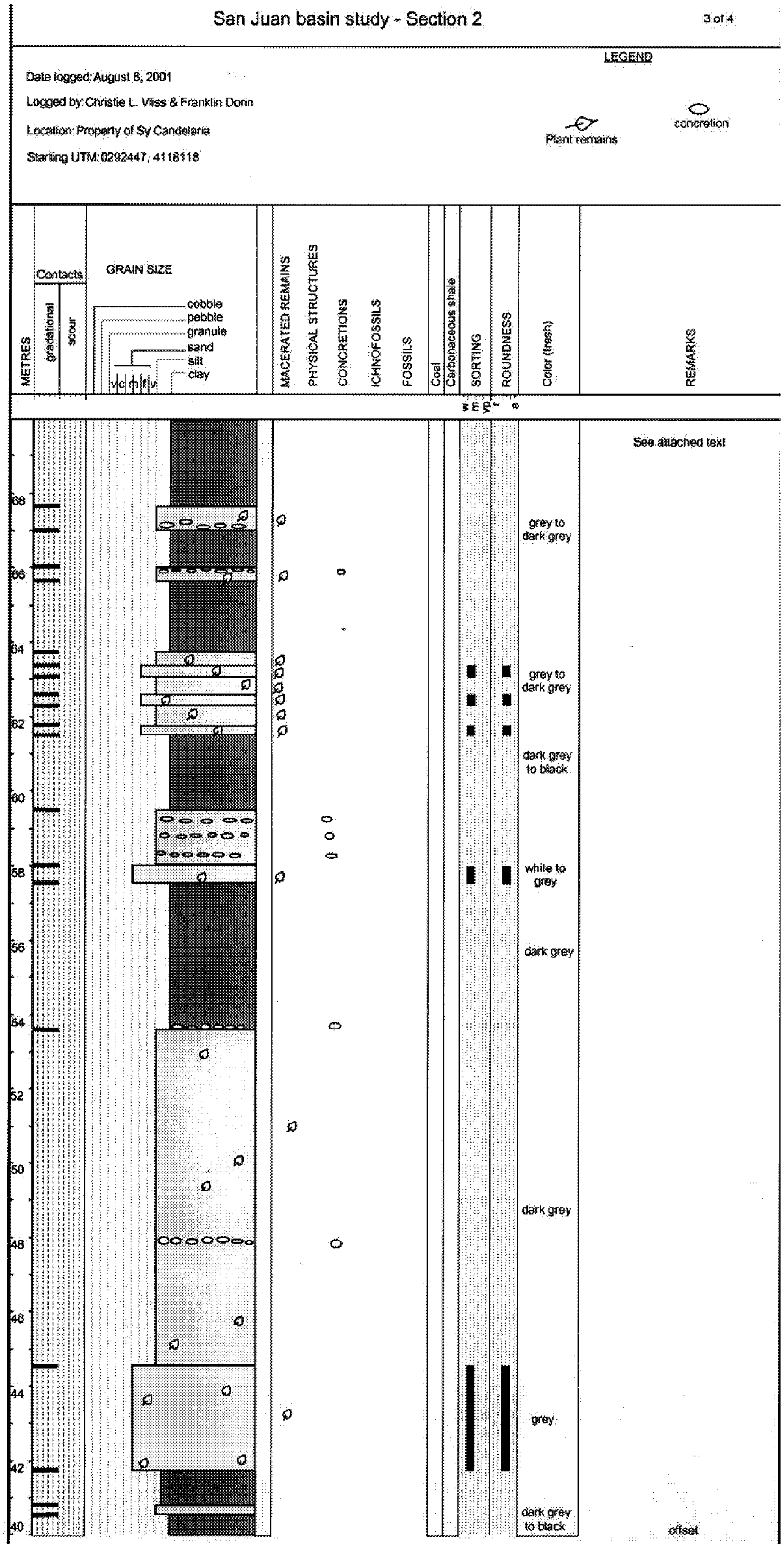


San Juan basin study - Section 2
1 of 4
LEGEND
Date Logged: August 8, 2001
Logged by: Christie Vliss & Franklin Dorin
Location: Property of Sy Candelaria
Starting UTM 0292434, 4118124
Plant remains
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
See attached text
offset
cover
black to dark grey
dark grey to grey
black
grey
black
dark grey
grey
black
black
grey
grey
black
Section started on top of Pictured Cliffs outcrop

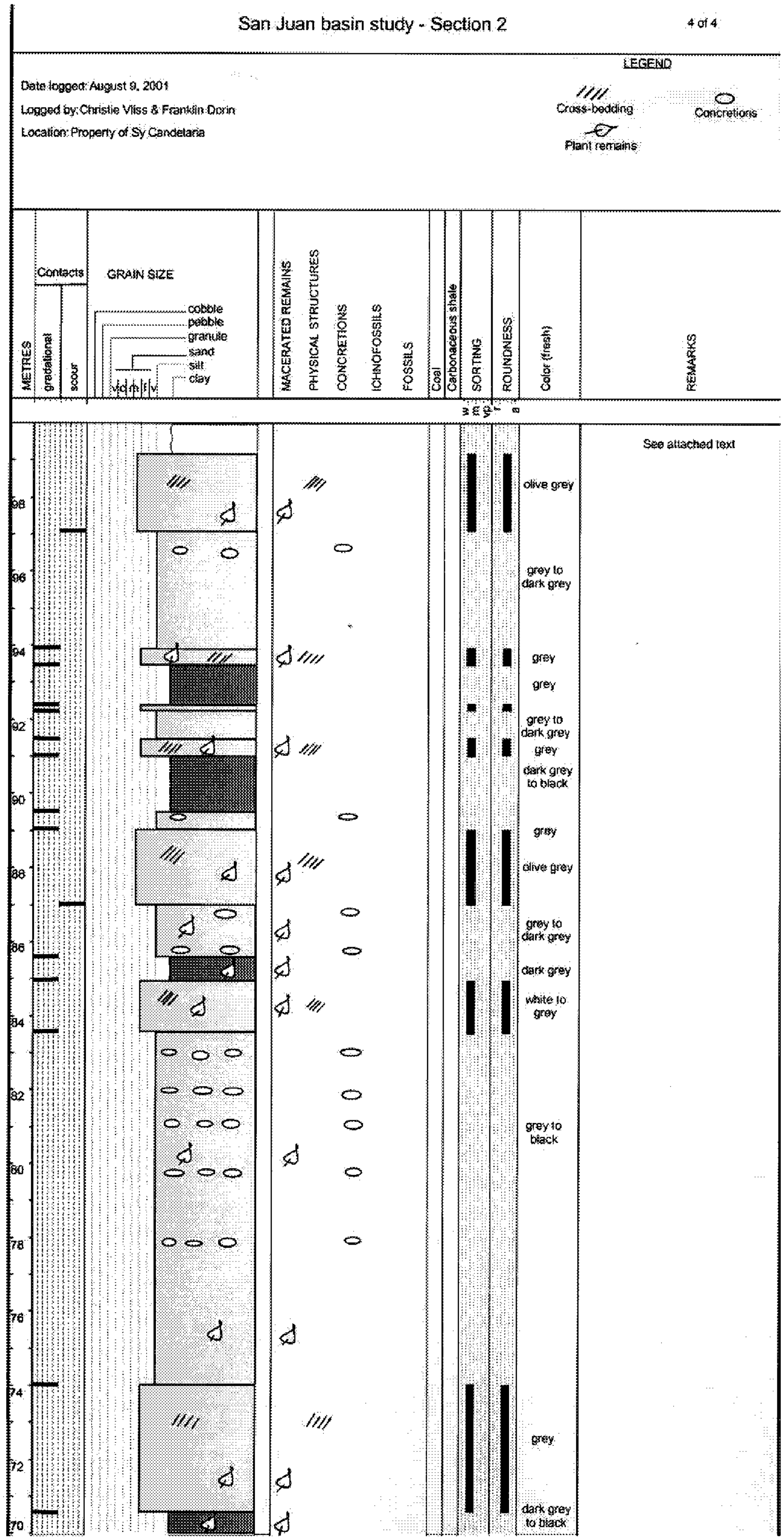
Section 2.1


San Juan basin study - Section 2
2 of 4
LEGEND
Date logged: August 9, 2001
Logged by: Christie Vliss & Franklin Dorin
Location: Property of Sy Candelaria
UTM: 0292434, 4118124
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
vc c m f vf
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
w m p vp
ROUNDNESS
r a
Color (fresh)
REMARKS
See attached text
cover
grey
black to dark grey
cover
black to dark grey
cover
38
36
34
32
30

Section 2.2


San Juan basin study - Section 2
3 of 4
Date logged: August 6, 2001
Logged by: Christie L. Vliss & Franklin Dorin
Location: Property of Sy Candelaria
Starting UTM: 0292447, 4118118
LEGEND
Plant remains
concretion
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
See attached text
grey to dark grey
grey to dark grey
dark grey to black
white to grey
dark grey
dark grey
grey
dark grey to black
offset

Section 2.3


San Juan basin study - Section 2
4 of 4
Date logged: August 9, 2001
Logged by: Christie Vliss & Franklin Dorin
Location: Property of Sy Candelaria
LEGEND
Cross-bedding
Concretions
Plant remains
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
See attached text
olive grey
grey to dark grey
grey
grey
grey to dark grey
grey
dark grey to black
grey
olive grey
grey to dark grey
dark grey
white to grey
grey to black
grey
dark grey to black

Section 2.4

Section 2
Location: Chimney Rock Quadrangle
Property of Sy Candelaria
Section was started at Pictured Cliffs/Fruitland contact overlooking the Piedra River valley
T34N R5W S13U
UTM 292434, 4118124

Meter	Description
19.00-20.0	cover
17.50-19.0	black to dark grey, fissile shale; some clinker float on surface
15.50-17.50	interbedded shale and siltstone; siltstone grey, hackly, some macerated plant remains; shale dark grey, fissile; gradational contacts
14.60-15.50	coal
14.30-14.60	siltstone, grey, hackly, yellow staining
13.25-14.30	coal, black, cleaty, some vitreous, some silty, yellow staining
12.00-13.25	carbonaceous shale, black to dark grey; gradational contacts
11.25-12.0	interbedded shale and siltstone; siltstone grey, hackly; shale black to dark grey, fissile; contacts gradational
10.50-11.25	coal, black, cleaty, some vitreous, some containing silt; gradational contacts
7.50-10.50	carbonaceous black shale, coal stringers becoming more frequent near top; coal shiny, cleaty
6.00-7.50	interbedded very fine sandstone and siltstone; sandstone grey, friable, some macerated plant remains; siltstone grey, hackly
1.50-6.0	very fine upper sandstone, macerated plant remains at base of faint bedding planes, very weathered and friable; sandstone contains quartz, black accessory minerals, mud/clay
0-1.50	carbonaceous shale, fissile; coal stringers shiny, black, cleaty

Section 2 offset
Location: Chimney Rock Quadrangle
Property of Sy Candelaria
Section measured was started on valley floor near visible outcrop of Pictured Cliffs/Fruitland contact on east side of valley
T34N R5W S13U
UTM 292131, 4117937

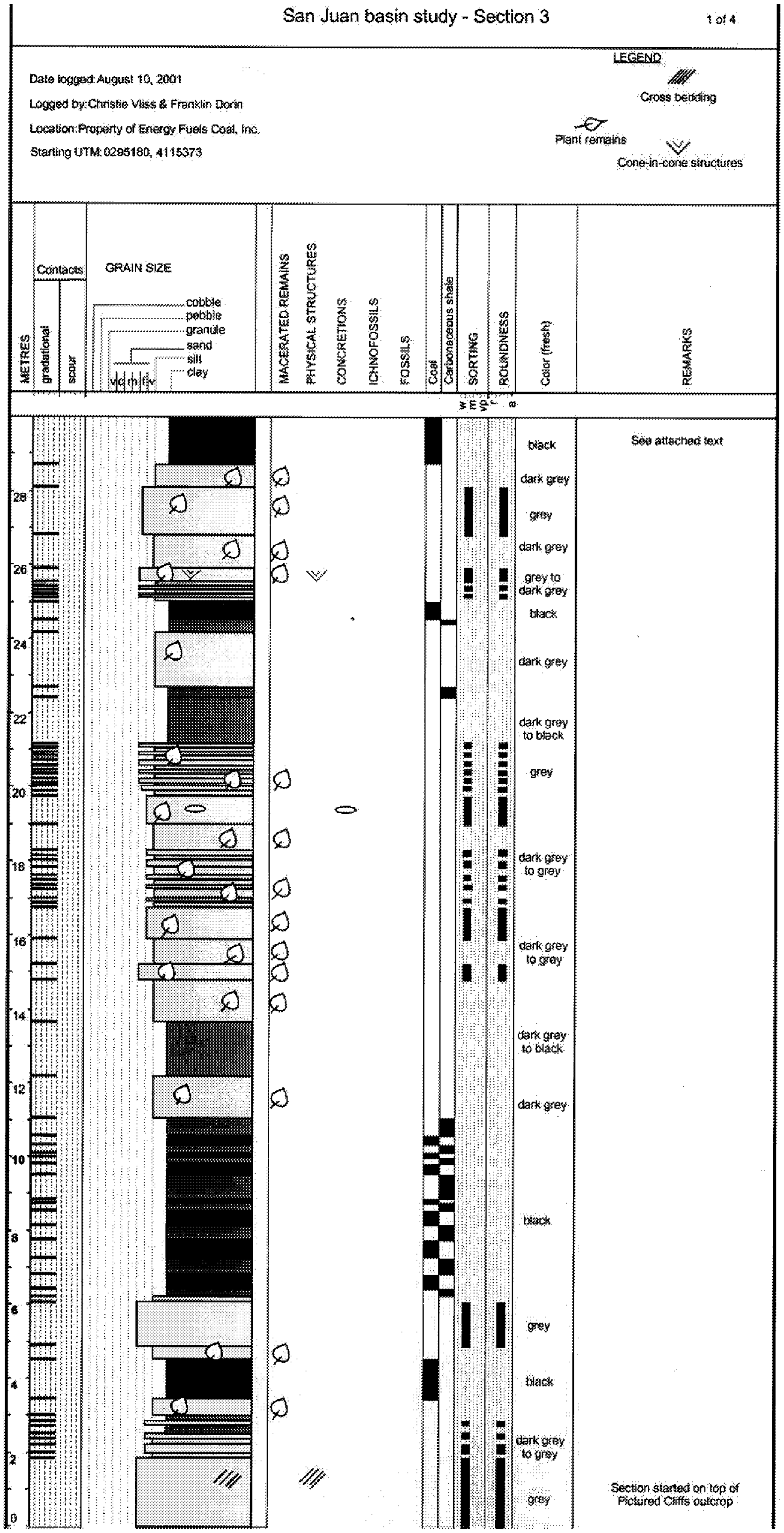
Meter	Description
36.00-37.50	cover; some shale visible in soil
34.50-36.0	black to dark grey, fissile shale
20.00-34.50	cover; beginning of section is valley fill, upper third slope and vegetation cover

Section 2 offset
Location: Chimney Rock Quadrangle
Property of Sy Candelaria
This section begins the offset of Sy2b1-2b2. The siltstone unit at 38.25m in Sy2b1-2b2 was traced laterally into the next drainage bearing towards the west-southwest.
T34N R5W S13U
UTM 292122, 4117904

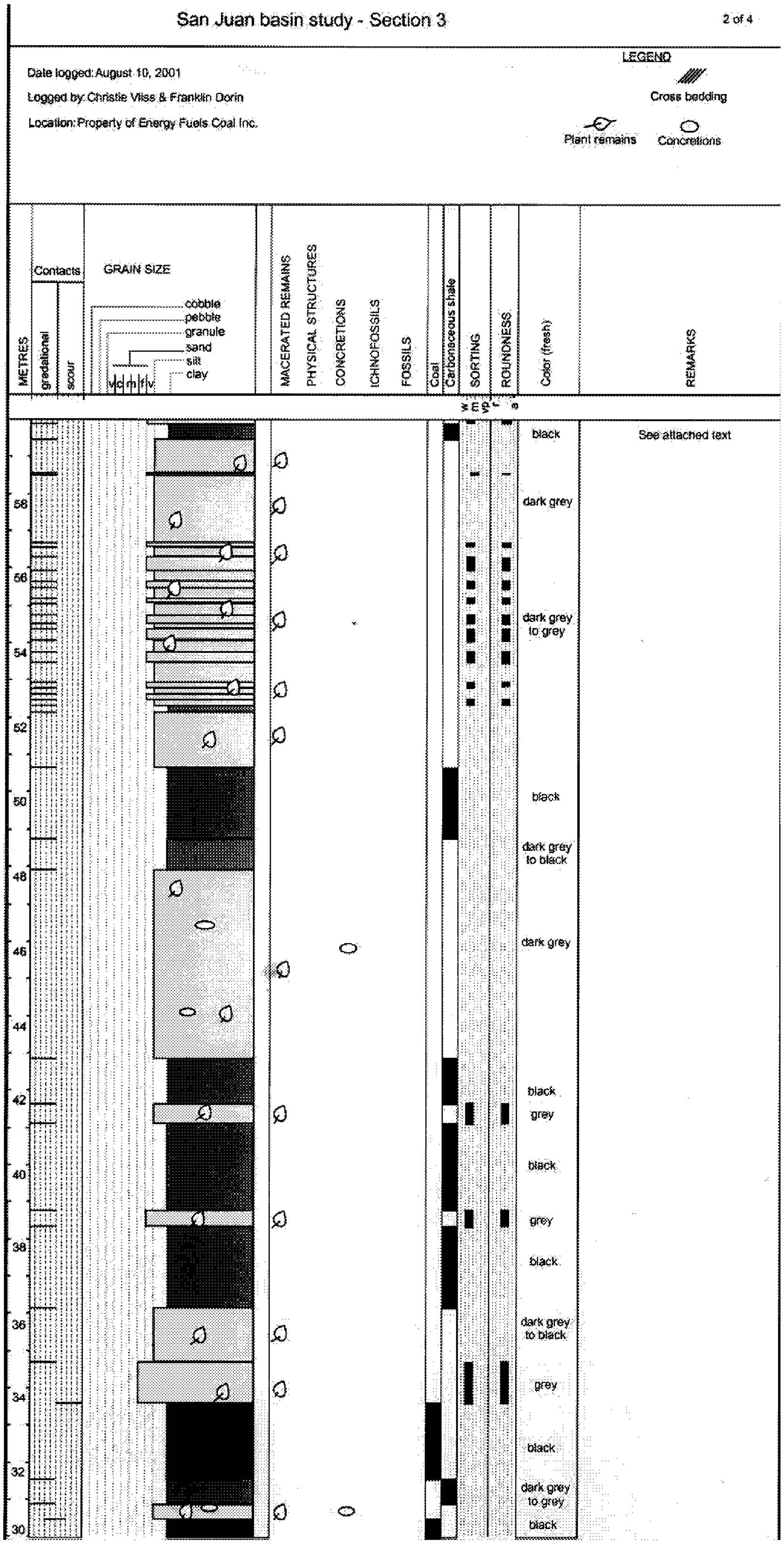
Meter	Description
97.25-99.25	olive-grey sandstone, fine upper to medium lower grains, moderate sorting, sub angular to sub rounded grains, weathered colors red to yellow to tan, rip-up clasts at base, macerated plant remains, trough cross bedding; lower contact scoured and sharp
93.90-97.25	interbedded shale, siltstone, siltstone with abundant concretions; shale dark grey, fissile; siltstone grey, hackly; concretions well cemented, dark grey fresh color, deep red weathered color; thickness changes laterally; gradational lower contact
93.5-93.9	grey sandstone, fine upper-fine lower grains, well cemented, slightly calcitic, moderate sorting, sub angular to sub rounded grains, faint bedding, very friable; gradational contacts
92.60-93.5	dark grey, fissile shale
92.50-92.60	grey sandstone, fine upper-fine lower grains, well cemented, slightly calcitic, moderate sorting, sub

	angular to sub rounded grains, very friable; gradational contacts
91.50-92.50	interbedded siltstone and shale; siltstone hackly, grey; shale dark grey, fissile
91.25-91.50	grey sandstone, fine upper-fine lower grains, subrounded grains, calcitic cement, dark brown weathered color, some macerated plant remains at base; gradational contacts
89.5-91.25	dark grey to black, fissile shale
89-89.5	grey, hackly siltstone with laterally discontinuous, well cemented concretions; concretions weather deep red; gradational contacts
87-89	olive grey sandstone, weathers yellow to orange to brown, trough cross bedding, fine upper grains, well sorted, cloudy, weakly calcitic cement, macerated remains at base, very friable; 15cm thick shale that pinches out laterally; sandstone composed of quartz, feldspar, black accessory mineral; lower contact scoured
85.7-87	interbedded siltstone and siltstone with abundant concretions; grey, hackly siltstone with macerated plant remains; concretions weather deep red, dark grey fresh color, well cemented, slightly calcitic, some plant remains
84.90-85.70	dark grey, fissile shale; gradational contacts
83.70-84.90	white to grey sandstone, fine upper-med lower grains, cloudy cement, very friable, macerated plant remains, trough cross bedding, calcitic cement, slope former
74.10-83.70	interbedded siltstone, shale, concretions; lower portion interbedded grey, hackly siltstone with black to dark grey, fissile shale; siltstone has some oxidation staining and macerated plant remains; four meters up from base is the beginning of interbedding with well cemented concretion; concretions dark grey fresh color, deep red and orange weathered color, calcitic, have plant and leaf remains, gradational contacts
70.50-74.10	grey sandstone, weathers yellow to tan to orange color, cloudy cement, fine lower-medium upper grains, trough cross bedding, poor sorting, very friable, weathers along weak bedding planes, macerated plant remains

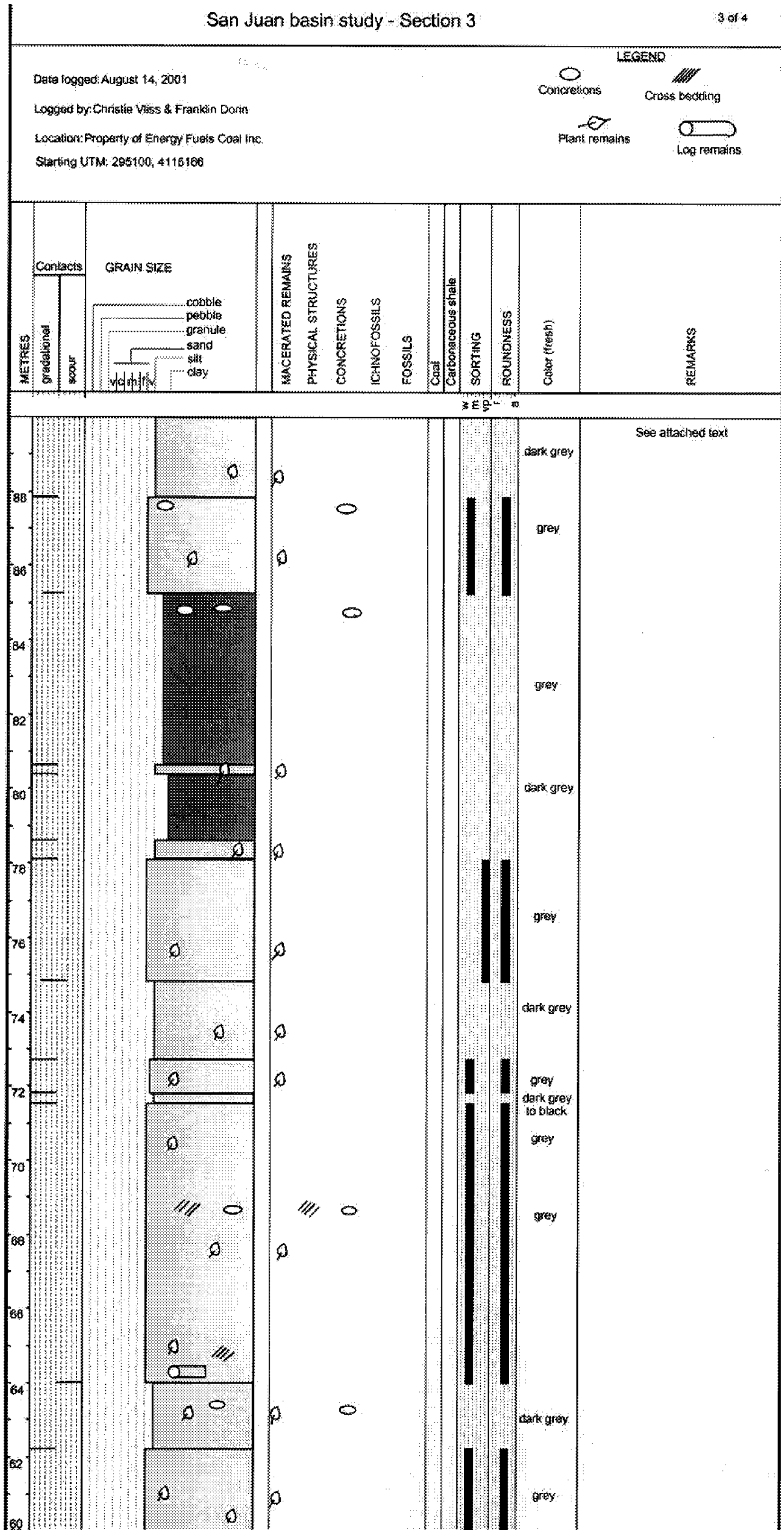
63.75-70.50	interbedded shale, siltstone, concretions; shale dark grey to black, fissile; siltstone dark grey fresh, hackly; concretions dark grey fresh color, deep red to orange weathered color, well cemented, slightly calcitic, macerated plant and leaf remains; gradational contacts
61.5-63.75	interbedded sandstone, siltstone, siltstone with abundant concretions, shale; sandstone grey fresh color, fine upper-medium lower grains, slightly calcitic, macerated plant remains, sub angular to subrounded grains; siltstone grey fresh color, some iron oxide staining, macerated plant remains; concretions well cemented, dark grey fresh color, deep red to brown weathered color, plant remains
58.0-61.5	interbedded shale and concretions; shale dark grey to black, fissile; concretions well cemented, dark grey fresh color, deep red to orange weathered color, calcitic, resistant ledge formers; gradational contacts
57.5-58.0	white to grey sandstone, fine upper-medium lower grains, very friable, faint trough cross bedding, calcitic cement, macerated plant remains, contains quartz, black accessory mineral
53.7-57.5	dark grey shale, some red to orange staining, fissile; gradational contact
44.5-53.7.1.1	interbedded shale and siltstone grading into all shale for upper two-thirds of unit; shale dark grey, fissile; siltstone dark grey, hackly, macerated plant remains; concretions appear at 7.90m and at the top of unit; concretions dark grey fresh color, deep red weathered color, slightly calcitic, well cemented, plant and leaf remains
41.8-44.5	grey sandstone, weathers orange to deep red, fine upper grains at base, very fine upper grains near top, calcitic cement, trough cross bedding, sub angular to sub rounded grains, 1-30cm beds, macerated plant remains at base of beds, gradational upper and lower contacts
40.5-41.8	interbedded shale and siltstone; shale dark grey, fissile; siltstone dark grey, hackly, local oxidation staining, gradational upper and lower contacts
40.00-40.50	dark grey to black, fissile shale


San Juan basin study - Section 3
1 of 4
Date logged: August 10, 2001
Logged by: Christie Vliss & Franklin Dorin
Location: Property of Energy Fuels Coal, Inc.
Starting UTM: 0295180, 4115373
LEGEND
Cross bedding
Plant remains
Cone-in-cone structures
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
black
dark grey
grey
dark grey
grey to dark grey
black
dark grey
dark grey to black
grey
dark grey to grey
dark grey to grey
dark grey to black
dark grey
black
grey
black
dark grey to grey
grey
See attached text
Section started on top of Pictured Cliffs outcrop

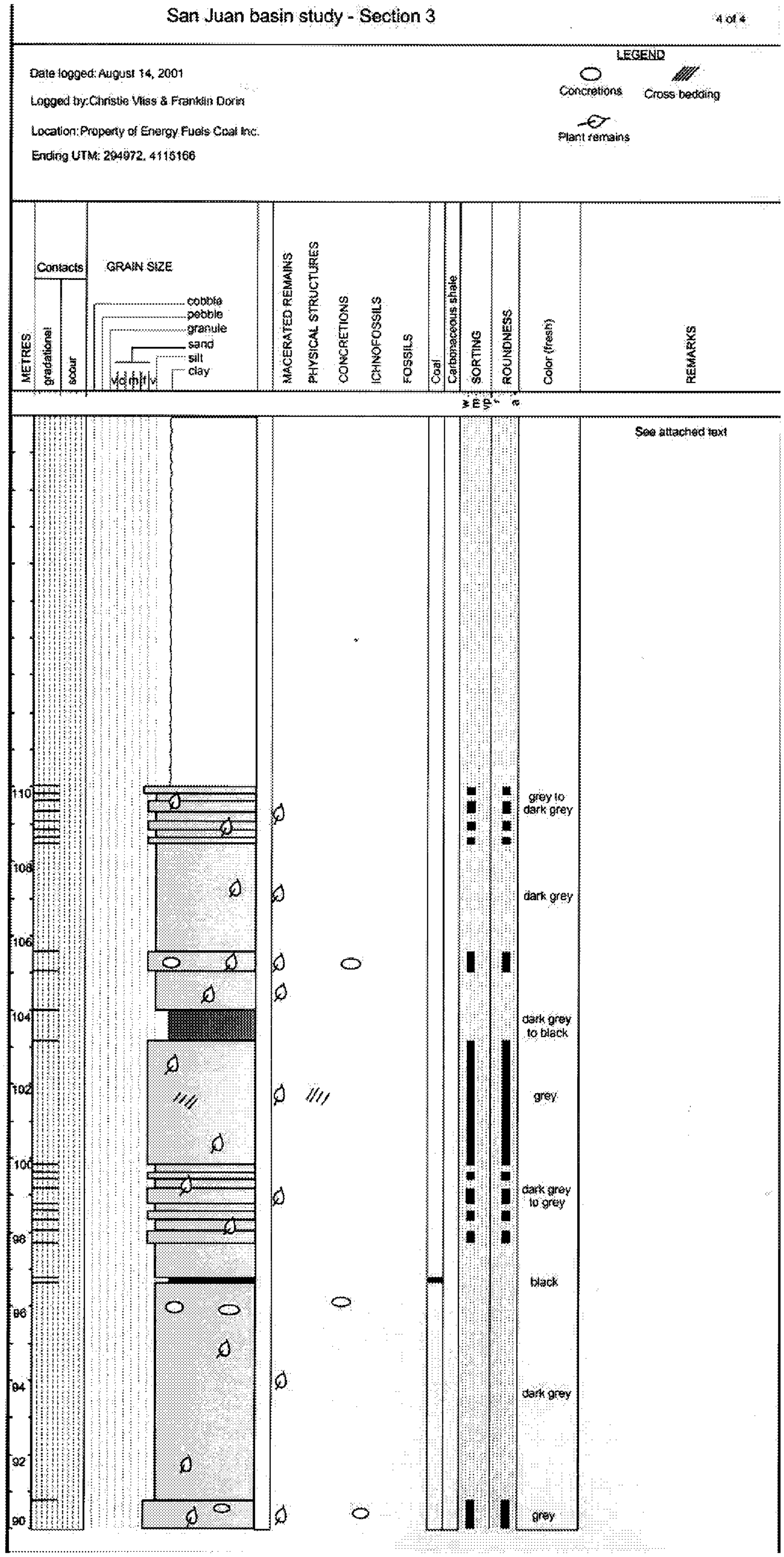
Section 3.1


San Juan basin study - Section 3
2 of 4
Date logged: August 10, 2001
Logged by: Christie Vliss & Franklin Dorin
Location: Property of Energy Fuels Coal Inc.
LEGEND
Cross bedding
Plant remains
Concretions
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
vc m f v
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
w m vp
r a
58
56
54
52
50
48
46
44
42
40
38
36
34
32
30
black
dark grey
dark grey to grey
black
dark grey to black
dark grey
black
grey
black
grey
black
dark grey to black
grey
black
dark grey to grey
black
See attached text

Section 3.2


San Juan basin study - Section 3
3 of 4
Date logged: August 14, 2001
Logged by: Christie Vliss & Franklin Dorn
Location: Property of Energy Fuels Coal Inc.
Starting UTM: 295100, 4115166
LEGEND
Concretions
Cross bedding
Plant remains
Log remains
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
vf f m c vc
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
See attached text
dark grey
grey
grey
dark grey
grey
dark grey
grey
dark grey to black
grey
grey
dark grey
grey
88
86
84
82
80
78
76
74
72
70
68
66
64
62
60

Section 3.3


San Juan basin study - Section 3
4 of 4
Date logged: August 14, 2001
Logged by: Christie Viiss & Franklin Dorin
Location: Property of Energy Fuels Coal Inc.
Ending UTM: 294972, 4115166
LEGEND
Concretions
Cross bedding
Plant remains
METRES
Contacts
gradational
scour
GRAIN SIZE
cobble
pebble
granule
sand
silt
clay
MACERATED REMAINS
PHYSICAL STRUCTURES
CONCRETIONS
ICHNOFOSSILS
FOSSILS
Coal
Carbonaceous shale
SORTING
ROUNDNESS
Color (fresh)
REMARKS
See attached text
grey to dark grey
dark grey
dark grey to black
grey
dark grey to grey
black
dark grey
grey
110
108
106
104
102
100
98
96
94
92
90

Section 3.4

Section 3

Location: Chimney Rock Quadrangle
Property of Energy Fuels Coal Inc.
This section is located along the south side Highway 151 across from the private residential property known as Heath's Haven. This is located approximately 1 mile south of the Chimney Rock visitor's Center entrance.
T34N R4W S29
UTM 295180, 4115373

Meter	Description
110-108.5	interbedded grey sandstone and siltstone; sandstone weathers tan to orange, fine upper grains, sub angular to sub rounded grains, macerated plant remains; siltstone grey, hackly, few macerated plant remains
105.5-108.5	siltstone, grey, hackly, deep red staining, macerated plant remains, gradational contacts
105-105.5	grey sandstone, weathered grey to deep red color, very friable, macerated plant remains, contains well cemented concretions
104-105	siltstone, grey, hackly, deep red weathered, macerated plant remains, gradational contacts
103.3-104	shale, dark grey to black, fissile
99.8-103.3	sandstone, fresh color grey, weathers to grey to tan to red, 2cm bedding planes, faint cross bedding, very friable, macerated plant remains, contains quartz, black accessory mineral
97.8-99.8	interbedded sandstone and siltstone; grey sandstone, fine upper grains, macerated plant remains, very friable
96.7-97.8	siltstone, grey, hackly, weathers yellow to red color, macerated plant remains, contains concretions that are well cemented, dark grey fresh color, deep red weathered color, macerated plant remains
96.6-97.7	coal, laterally discontinuous, very cleaty, black, vitreous, conchoidal fracture
90.8-96.6	interbedded siltstone and shale; siltstone dark grey fresh color, weathers yellow to deep red color, hackly, macerated plant remains; shale dark grey to black, fissile

90-90.8	grey sandstone, fine grained, very friable, macerated plant remains, capped by well cemented concretions, macerated plant remains, dark grey fresh color, weathers orange to deep red color
87.9-90	siltstone, dark grey, hackly, macerated plant remains, deep red weathered color
85.4-87.9	grey sandstone, very fine upper-fine lower grains, thinly bedded, weathers yellow to tan, macerated plant remains; upper portion contains well cemented concretions, fresh color grey, weathered color deep red to orange, macerated plant remains
80.6-85.4	interbedded shale and siltstone; shale dark grey to black, fissile; siltstone grey, hackly, large amounts of macerated plant remains including log remains; upper portion contains well cemented concretions
78.6-80.6	dark grey shale with abundant clay plugs; clay pinkish-orange color, up to 20cm thick, laterally discontinuous; shale contains macerated plant remains, carbonized tree remains
78.15-78.6	siltstone, dark grey, hackly, macerated plant remains
74.85-78.15	grey sandstone, poorly sorted, very fine upper-medium lower grains, large amounts of macerated plant remains, weathers deep red color; upper portion of unit better sorted, very fine lower-fine lower grains, trough cross bedding, large amounts of macerated plant remains, contains well cemented concretions near top of unit
72.70-74.15	siltstone, dark grey, hackly, appears fissile in some places, contains zones of abundant amounts of macerated plant remains
71.85-72.70	sandstone, very fine grained, macerated plant remains, very friable, gradational contacts
71.55-71.85	siltstone, dark grey to black, hackly, weathers deep red
64-71.55	sandstone, very fine-fine lower grains, fresh color grey, lower fifteen cm of unit weathers to deep red color, very friable, trough cross bedding, large amounts of macerated plant remains, contains well cemented concretions at 68.80m, dark grey fresh color, weathered color deep red to orange, macerated plant remains
62.35-64	siltstone, dark grey, weathers to deep red color, hackly,

	contains well-cemented concretions, dark grey fresh, deep red weathered color, macerated plant remains
59.90-62.35	sandstone, grey fresh color, yellow staining, very fine grained, macerated plant remains, log remains at base of unit, faint thin bedding, very friable and weathered
59.50-59.90	carbonaceous shale
49.60-59.50	interbedded siltstone, sandstone, minor zone of shale; siltstone grey, hackly, macerated plant remains; sandstone grey, very fine-fine upper grains, weakly calcitic cement, muscovite, macerated plant remains, beds up to 40 cm thick, faint cross bedding, very friable; shale dark grey to black, fissile
47.60-49.60	carbonaceous shale, dark grey to black, fissile, some silt, coal stringers 1-8 cm thick, lateral variation in thickness, cleaty
46.90-47.60	shale, dark grey to black, fissile
42.90-46.90	interbedded siltstone and concretions; siltstone dark grey to red, hackly, some macerated plant remains; concretions well cemented, dark grey fresh color, weathered color deep red to orange, calcitic
41.60-42.90	carbonaceous shale, coal stringers .5-2 cm, silty, laterally discontinuous
41.10-41.60	sandstone, grey, fine upper-fine lower grains, macerated plant remains, friable
38.70-41.10	carbonaceous shale, dark grey to black, fissile, red staining
38.40-38.70	sandstone, grey fresh, weathered color orange to deep red, muscovite, quartz, calcitic, heavily macerated plant remains
36.15-38.40	carbonaceous shale
34.65-36.15	interbedded shale and siltstone; siltstone dark grey to grey, hackly, some macerated plant remains; shale black, fissile
33.70-34.65	sandstone, grey, fine upper subrounded grains, minor amounts muscovite, macerated plant remains, friable

31.50-33.70	coal
30.90-31.50	carbonaceous shale
30.40-30.90	interbedded siltstone and concretions; siltstone grey, hackly, macerated plant remains; concretions well cemented, dark grey fresh color, weathered color deep red to orange, macerated plant remains
28.70-30.40	coal, cleaty, some silt
28.10-28.70	siltstone, dark grey, hackly, macerated plant remains
26.85-28.10	sandstone, grey, very fine upper-very fine lower grains, weathered color olive to orange, macerated plant remains, faint bedding, very friable
25-26.85	interbedded siltstone and sandstone with siltstone bed for upper meter; siltstone grey, hackly, macerated plant remains; sandstone grey, very fine lower grains, weathered color white to orange, macerated plant remains, calcitic cement, cone-in-cone structures
24.50-25	coal
21.20-24.50	shale, siltstone, shale interval; shale dark grey to black, fissile; siltstone dark grey, hackly, macerated plant remains
13.80-24.50	interbedded siltstone, concretions, sandstone; siltstone grey, hackly, macerated plant remains, weathered color red, muscovite; concretions well cemented, dark grey fresh color, weathered color deep red, macerated plant remains; sandstone grey, fine upper-fine lower grains, weathers orange to red, macerated plant remains, slightly calcitic, very friable
12.20-13.80	shale, dark grey to black, fissile
6.30-12.20	interbedded coal and carbonaceous shale
4.50-6.30	sandstone, fresh color grey, weathered color tan to olive, friable; upper and lower portions contain siltstone that is dark grey, hackly, weathered color yellow to orange, macerated plant remains
3.50-4.50	coal
3.00-3.50	siltstone, black, hackly to fissile, red staining

1.80-3.0	interbedded shale and sandstone; shale dark grey, fissile localized deep red staining; sandstone grey, fine upper-fine lower grains, 5-8 cm thick beds, weathered color olive to tan, very friable
0-1.80	sandstone, grey fresh color, weathered color olive to tan, very friable, intense weathering, faint thin laminations, fine lower-fine upper grains

UTM Data Points: San Juan Basin Mapping Project

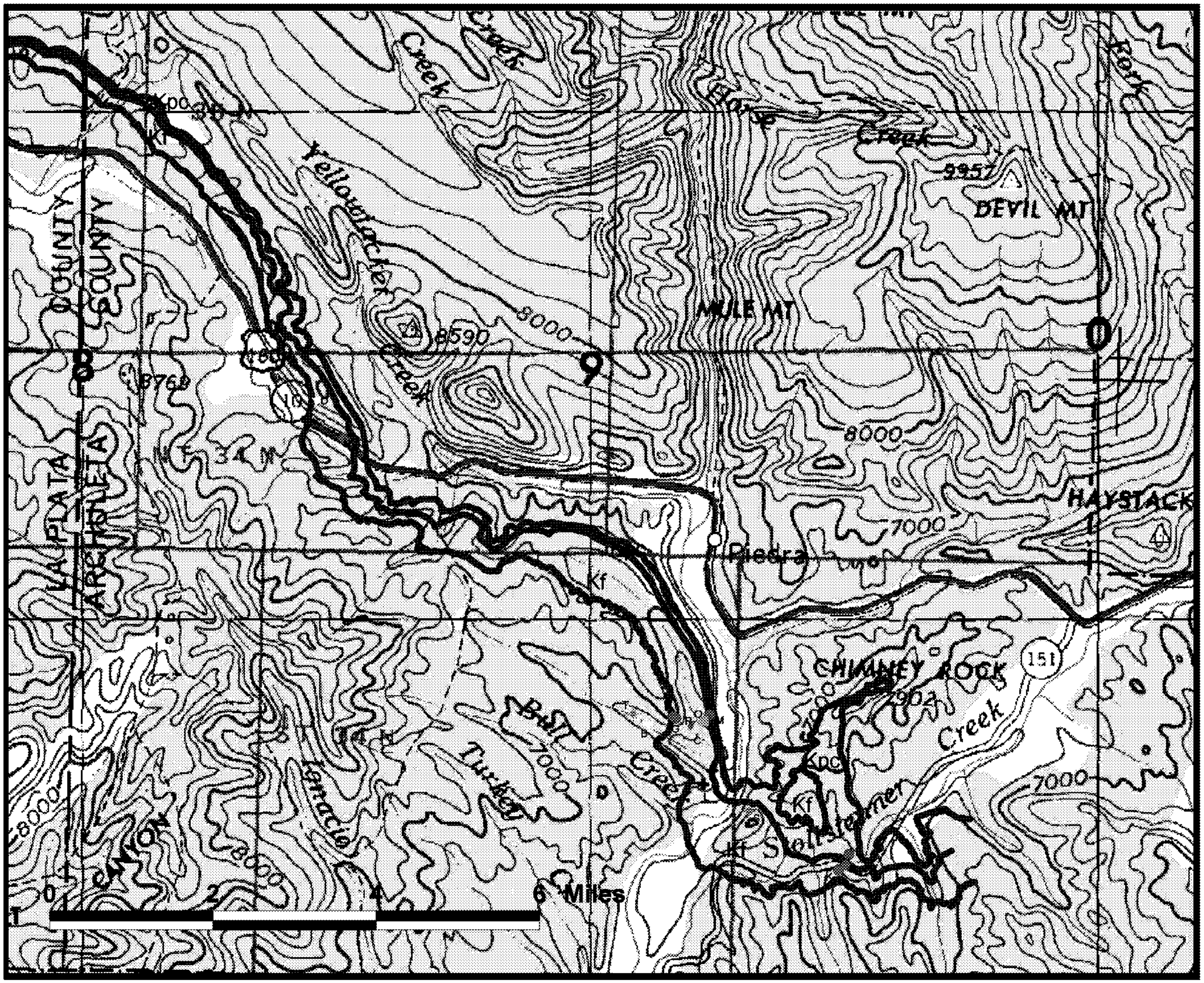
GPS	UTM	Comments
	Measured Sections	
MSEC1	285220, 4123562	Location of Measured Section #1 between Mile Markers 116 & 117 on Highway 160, Pargin Mountain Quadrangle, T34N R5W S9, map designation "N"
MSEC2	292434, 4118124	Location of beginning of Measured Section #2 on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "O"
MSEC2C	292447, 4118118	Location of offset of Measured Section #2 on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "P"
MSEC3	292122, 4117904	Location of offset of Measured Section #2 on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "R"
MSEC3C	291771, 4118061	Location of offset of Measured Section #2 on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "G"
MSEC3O	291720, 4118096	Location of offset of Measured Section #2 on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "H"
MSEC4	295180, 4115373	Location of Measured Section #3 on property of Energy Fuels Coal Inc., Chimney Rock Quadrangle, T34N R4W S29, map designation "I"
MSEC4C	295100, 4115166	Location of offset of Measured Section #3 on property of Energy Fuels Coal Inc., Chimney Rock Quadrangle, T34N R4W S29, map designation "J"
MSEC4F	294972, 4115076	Location of ending point of Measured Section #3 on property of Energy Fuels Coal Inc., Chimney Rock Quadrangle, T34N R4W S29, map designation "K"

Geologic Mapping Points		
GPS	**UTM**	**COMMENTS**
CHIMRX	**293213, 4116236**	**Hiked to this point to determine Pictured Cliffs contact south of Chimney Rock, Chimney Rock Quadrangle, T34N R4W S30, map designation "S"**
FOSWEL	**290928, 4118155**	**Location of drill hole on Fosset Gulch Road, Chimney Rock Quadrangle, T34N R5W S14U, map designation "T", drill hole labeled "B.H.P.R. Schomburg #1 SE.SE.14T34N R5W(SUL)"**
SYPCFT	**292173, 4117892**	**Location of Pictured Cliffs/Fruitland contact, east side of valley on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "C"**

Water Features		
GPS	**UTM**	**COMMENTS**
SPRIN1	**292316, 4118002**	**Location of wet spot in valley on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S13U, map designation "M", noted on 8/15/01, excessive moisture may be due to monsoon season, valley lies on Fruitland Formation, vegetation looks healthy, no bare spots, no odor**

GAS SEEPS		
STINK1	**292316, 4118002**	**Location of visible clinker float and noticeable odor on property of Sy Candelaria, Chimney Rock Quadrangle, T34N R4W S13U, map designation "A"**
STINK2	**291228, 4117904**	**Location of stressed narrow-leaf cottonwoods along Fosset Gulch Creek, Chimney Rock Quadrangle, T34N R5W S14U, map designation "B"**

Possible Transects		
TRAN1	**284689, 4124281**	**Location of possible transect in drainage approximately 440 feet on northern side of Highway 160 at Mile Marker 116, east side of Yellow Jacket Pass. Pargin Mountain Quadrangle, T34N R5W S4, map designation "D", odor detected along roadside entering meadow**
TRAN3	**292487, 4117030**	**Location of possible transect on Fosset Gulch Road, property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S24, map designation "F"**
PIEDR1	**292315, 4116760**	**Location of possible transect on Fosset Gulch Road, property of Sy Candelaria, Chimney Rock Quadrangle, T34N R5W S24, map designation "L"**



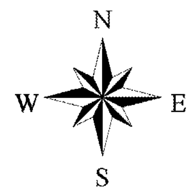
Geologic Features Near Piedra River

Legend

- Formation contacts
- seep
- contact location
- gas sample transect
- measured section
- wet land due to spring
- geologic feature
- drill hole

Kf Fruitland Formation

Kpc Pictured Cliffs Sandstone



Fieldwork and Cartography by:
Franklin Dorin
Jim Hughes
Christie Vliss
October 2, 2001

Appendix C

Fracture Study Results

Carbon Junction — **All fractures on transect (parallel to strike)** — **First transect on PC Sandstone**

Feet	# of Fractures	# of Stained	Comments
0 ft.-5 ft.	2	0	partial cover
5 ft.-10 ft.			cover
10 ft.-15 ft.	2	2	abundant staining
15 ft.-20 ft.	5	0	no staining
20 ft.-25 ft.	4	1	partial cover
25 ft.-30 ft.	3	0	partial cover
30 ft.-35 ft.			cover
35 ft.-40 ft.			cover
40ft.-45 ft.			cover
45 ft.-50 ft.			cover
50 ft.-55 ft.	1		no staining
55 ft.-60 ft.	3	1	
60 ft.-65 ft.	2		no staining
65 ft.-70 ft.	3		no staining
70 ft.-75 ft.	1	1	open fracture
75 ft.-80 ft.			cover
80 ft.-85 ft.	1		partial cover
85 ft.-90 ft.	2		open fracture
90 ft.-95 ft.	2	1	
95 ft.-100 ft.			cover

All data taken by Matt Janowiak and Jim Hughes on December 5, 2000

Ridges Basin All fractures on transect (parallel to strike) First transect on PC Sandstone

Feet	# of Fractures	# of Stained	Comments
0 ft.-5 ft.	1	1	closed
5 ft.-10 ft.			massive sandstone
10 ft.-15 ft.			massive sandstone
15 ft.-20 ft.	2		partial cover
20 ft.-25 ft.			cover
25 ft.-30 ft.			cover
30 ft.-35 ft.	1		partial cover
35 ft.-40 ft.	1		no staining
40ft.-45 ft.	1		no staining
45 ft.-50 ft.	2		no staining
50 ft.-55 ft.	1		open
55 ft.-60 ft.			massive sandstone
60 ft.-65 ft.			massive sandstone
65 ft.-70 ft.	1		open
70 ft.-75 ft.			massive sandstone
75 ft.-80 ft.			massive sandstone
80 ft.-85 ft.			massive sandstone
85 ft.-90 ft.			massive sandstone
90 ft.-95 ft.			massive sandstone
95 ft.-100 ft.	1		partial cover

All data taken by Matt Janowiak and Jim Hughes on December 5, 2000

Ridges Basin All fractures on transect (parallel to strike)

Second transect on PC Sandstone
continues from transect #1

Feet	# of Fractures	# of Stained	Comments
0 ft.-5 ft.	2		no staining
5 ft.-10 ft.	2		no staining, partial cover
10 ft.-15 ft.	3		no staining, partial cover
15 ft.-20 ft.	1		no staining, partial cover
20 ft.-25 ft.	1		no staining, partial cover
25 ft.-30 ft.	1		no staining, partial cover
30 ft.-35 ft.	2		no staining, partial cover
35 ft.-40 ft.			cover
40ft.-45 ft.	1		no staining
45 ft.-50 ft.	2		no staining
50 ft.-55 ft.	2		no staining
55 ft.-60 ft.	2		open
60 ft.-65 ft.	1		closed
65 ft.-70 ft.			cover
70 ft.-75 ft.	2	1	partial cover
75 ft.-80 ft.	2		no staining
80 ft.-85 ft.	1		massive sandstone
85 ft.-90 ft.	3		open
90 ft.-95 ft.	1		open
95 ft.-100 ft.			massive sandstone

All data taken by Matt Janowiak and Jim Hughes on December 5, 2000

Ridges Basin All fractures on transect (parallel to strike) Third transect on PC Sandstone continued along strike from transect #2

Feet	# of Fractures	# of Stained	Comments
0 ft.-5 ft.	1		no staining
5 ft.-10 ft.	1		no staining, partial cover
10 ft.-15 ft.	2		no staining
15 ft.-20 ft.			cover
20 ft.-25 ft.			partial cover, no fractures exposed
25 ft.-30 ft.	1		no staining
30 ft.-35 ft.			cover
35 ft.-40 ft.	1		no staining
40ft.-45 ft.	1	1	
45 ft.-50 ft.			massive sandstone
50 ft.-55 ft.	1		open
55 ft.-60 ft.	2		open
60 ft.-65 ft.			cover
65 ft.-70 ft.	1		open
70 ft.-75 ft.			massive sandstone
75 ft.-80 ft.			massive sandstone
80 ft.-85 ft.	1		open
85 ft.-90 ft.			massive sandstone
90 ft.-95 ft.			massive sandstone
95 ft.-100 ft.			massive sandstone

All data taken by Matt Janowiak and Jim Hughes on December 5, 2000

Appendix D

Hydrologic Modeling Run Summary

Summary	Animas – Basin Creek Ground water Model
Project	San Juan Basin Ground Water Modeling Study Ground Water - Surface Water Interaction Between Coalbed Methane Formations and Rivers
Area	San Juan Basin in south-west Colorado
Modeler(s)	Jim Thomson, Rick Reinke, Seth Okeson (AHA)
Type of model	Ground water flow
Code	Visual MODFLOW® v. 2.8.2.52
Time modeled	Approx. 1975 (Pre-CBM development)
Dimensions	X = $8^{1}/_{3}$ miles, Y = $7^{1}/_{6}$ miles (60 sq. miles)
X coords	World: 1,559,570 – 1,603,570 ft; Model: 0 – 44,000 ft ($8^{1}/_{3}$ miles)
Y coords	World: 13,495,590 – 13,533,430 ft; Model: 0 – 37,840 ft ($7^{1}/_{6}$ miles)
Coordinates	UTM 12.1 ft, Central Meridian = 107^{o} 39’ W
Rows, columns	43 x 50 (total 2,150 cells)
Grid spacing	880 feet ($^{1}/_{6}$ mile)
Lateral boundaries	<u>Northwest</u>: impermeable (outcrop) <u>North:</u> constant-head (representing the rest of the SJ Basin), partial <u>South</u>: constant-head (representing the rest of the SJ Basin) <u>East</u>: constant-head (representing the rest of the SJ Basin) <u>West</u>: constant-head (representing the rest of the SJ Basin), partial
Surfaces	Detailed outcrop base map: Colorado Geological Survey (2000), digitized by Applied Hydrology Associates, Inc. Coal package surfaces, permeability, porosity: Questa Engineering, Inc. (2000) Steady-state potentiometric surface: AHA (2000) Surface topography: USGS DEMs

Layers and Properties	**$K_{x,y}$** (md)	**K_z** (md)	**S_s** (1/ft)	**SY**	**Φ**
Kirtland Shale	Imperm.	cap			
Fruitland Formation – Shales	0.001	0.001	0.00001	Φ	Per 3M
Fruitland Formation – Coals	Per 3M	Per 3M	0.00001	Φ	Per 3M
Pictured Cliffs Sandstone	100	10	0.00001	Φ	Per 3M
Lewis Shale	Imperm.	base.			

Wells	Not part of the steady-state model
Recharge	From Applied Hydrology Associates (2000)
Discharge to streams	Evaluated by model
Solver	WHS (Waterloo Hydrologic Solver)
Layer type	Layers 1-11 Variable T, S
Runs	1. Single layer using net coal, entire SJ Basin, repeat 3M results at 1/6-mile grid, using v. 2.8.2.52.
	2. Single layer of Animas River and Basin Creek subarea using net coal. Compare results with #1.
	3. Multiple layer of subarea with coal packages. Compare results with #2. Final discharge prediction

Summary	***Florida River Ground water Model***
Project	San Juan Basin Ground Water Modeling Study Ground Water - Surface Water Interaction Between Coalbed Methane Formations and Rivers
Area	San Juan Basin in south-west Colorado
Modeler(s)	Jim Thomson, Rick Reinke, Seth Okeson (AHA)
Type of model	Ground water flow
Code	Visual MODFLOW® v. 2.8.2.52
Time modeled	Approx. 1975 (Pre-CBM development)
Dimensions	X = $5^{5}/_{6}$ miles, Y = $3^{1}/_{2}$ miles (20 sq. miles)
X coords	World: 1,583,330 – 1,614,130 ft; Model: 0 – 30,800 ft ($5^{5}/_{6}$ miles)
Y coords	World: 13,533,430 – 13,551,910 ft; Model: 0 – 18,480 ft ($3^{1}/_{2}$ miles)
Coordinates	UTM 12.1 ft, Central Meridian = 107° 39' W
Rows, columns	21 x 35 (total 735 cells)
Grid spacing	880 feet ($^{1}/_{6}$ mile)
Lateral boundaries	Northwest: impermeable (outcrop) South: constant-head (representing the rest of the SJ Basin) East: constant-head (representing the rest of the SJ Basin)
Surfaces	Detailed outcrop base map: Colorado Geological Survey (2000), digitized by Applied Hydrology Associates, Inc. Coal package surfaces, permeability, porosity: Questa Engineering, Inc. (2000) Steady-state potentiometric surface: AHA (2000) Surface topography: USGS DEMs

Layers and Properties	$K_{x,y}$ (md)	K_z (md)	S_s (1/ft)	**SY**	Φ
Kirtland Shale	Imperm.	cap			
Fruitland Formation - Shales	0.001	0.001	0.00001	Φ	Per 3M
Fruitland Formation - Coals	Per 3M	Per 3M	0.00001	Φ	Per 3M
Pictured Cliffs Sandstone	100	10	0.00001	Φ	Per 3M
Lewis Shale	Imperm.	base.			

Wells	Not part of the steady-state model
Recharge	From Applied Hydrology Associates (2000)
Discharge to streams	Evaluated by model
Solver	WHS (Waterloo Hydrologic Solver)
Layer type	Layers 1-11 Variable T, S
Runs	1. Single layer using net coal, entire SJ Basin, repeat 3M results at 1/6-mile grid, using v. 2.8.2.52.
	2. Single layer of Florida River and Horse Gulch subarea using net coal. Compare results with #1.
	3. Multiple layer of subarea with coal packages. Compare results with #2. Final discharge prediction.

Summary	***Pine River Ground water Model***
Project	San Juan Basin Ground Water Modeling Study Ground Water - Surface Water Interaction Between Coalbed Methane Formations and Rivers
Area	San Juan Basin in south-west Colorado
Modeler(s)	Jim Thomson, Rick Reinke, Seth Okeson (AHA)
Type of model	Ground water flow
Code	Visual MODFLOW® v. 2.8.2.52
Time modeled	Approx. 1975 (Pre-CBM development)
Dimensions	X = 5 miles, Y = 4 miles (20 sq. miles)
X coords	World: 1,645,810 – 1,672,210 ft; Model: 0 – 26,400 ft (5 miles)
Y coords	World: 13,530,790 – 13,551,910 ft; Model: 0 – 21,120 ft (4 miles)
Coordinates	UTM 12.1 ft, Central Meridian = 107° 39' W
Rows, columns	24 x 30 (total 720 cells)
Grid spacing	880 feet ($^{1}/_{6}$ mile)
Lateral boundaries	North: impermeable (outcrop) South: constant-head (representing the rest of the SJ Basin) East: constant-head (representing the rest of the SJ Basin) West: constant-head (representing the rest of the SJ Basin)
Surfaces	Detailed outcrop base map: Colorado Geological Survey (2000), digitized by Applied Hydrology Associates, Inc. Coal package surfaces, permeability, porosity: Questa Engineering, Inc. (2000) Steady-state potentiometric surface: AHA (2000) Surface topography: USGS DEMs

Layers and Properties	**$K_{x,y}$** (md)	**K_z** **(md)**	**S_s** (1/ft)	**SY**	**Φ**
Kirtland Shale	Imperm.	cap			
Fruitland Formation - Shales	0.001	0.001	0.00001	Φ	Per 3M
Fruitland Formation - Coals	Per 3M	Per 3M	0.00001	Φ	Per 3M
Pictured Cliffs Sandstone	100	10	0.00001	Φ	Per 3M
Lewis Shale	Imperm.	base.			

Wells	Not part of the steady-state model
Recharge	From Applied Hydrology Associates (2000)
Discharge to streams	Evaluated by model
Solver	WHS (Waterloo Hydrologic Solver)
Layer type	Layers 1-7 Variable T, S
Runs	1. Single layer using net coal, entire SJ Basin, repeat 3M results at 1/6-mile grid, using v. 2.8.2.52.
	2. Single layer of Pine River subarea using net coal. Compare results with #1.
	3. Multiple layer of subarea with coal packages. Compare results with #2. Final discharge prediction.