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Summary of the Technical Workshop on Well Construction/Operation and Subsurface Modeling
April 16–17, 2013
and
Subsurface Modeling Technical Follow-up Discussion
June 3, 2013

EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources:
Summary of April 16–17, 2013, Technical Workshop on Well Construction/Operation and Subsurface Modeling and
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Disclaimer

This report was prepared by EPA with assistance from Eastern Research Group, Inc., an EPA contractor, as a general record of discussions during the April 16–17, 2013, technical workshop on well construction/operation and subsurface modeling and the follow-up technical workshop on subsurface modeling held on June 3, 2013. The workshops were held to inform EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The report summarizes the presentations and facilitated discussions on the workshop topics and is not intended to reflect a complete record of all discussions. All statements and opinions expressed represent individual views of the invited participants; there was no attempt to reach consensus on any of the technical issues being discussed. Except as noted, none of the statements in the report represent analyses or positions of EPA.

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Meeting Agendas

Technical Workshop on Well Construction/Operation and Subsurface Modeling
April 16-17, 2013

US EPA Research Triangle Park Campus
"C" Building Auditorium
Research Triangle Park, NC

April 16: Well Construction/Operation

8:00 am   **Registration/Check-in**

8:30 am   **Welcome and Introductions** .... *Ramona Trovato, US EPA*

8:40 am   **Opening Remarks** .... *Glenn Paulson, Science Advisor, US EPA*

8:45 am   **Purpose of Workshop and Industry Perspective** .... *Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

Session 1: Well Design and Construction to Protect Drinking Water

8:55 am   *Panel:*

- **Proposed Analysis from the Well File Review** .... *Jeanne Briskin and Nathan Wiser, US EPA*

- **Geophysical Logging for Characterization of Fresh- and Saline Water Flow Zones in the Fractured Bedrock of the Northern Appalachian Basin** .... *John Williams, USGS*

- **An Overview of Well Construction and Well Integrity Related to Hydraulically Fractured Wells** .... *Talib Syed, TSA, Inc.*

- **Oil and Gas Well Cementing** .... *D. Steven Tipton, Newfield Exploration Company*

- **Zonal Isolation Methods Available to Operators for Groundwater Aquifer Protection** .... *Anthony Badalamenti, Halliburton Energy Services, Inc.*

Questions of Clarification

Break (10 minutes)

Facilitated discussion among workshop participants focusing on key questions:

− What current techniques are designed to prevent leaks through production well tubulars and fluid movement along the wellbore?

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- What factors are typically used to ensure adequate confinement of fluids that can move?

- How are ground water resources identified and documented prior to and during production well installation?

- What is the breadth of approaches?

12:20 pm   **Summary of Session 1** .... *Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

12:30 pm   **Lunch (on your own) and Poster Session**

Session 2: Well Operation and Monitoring to Protect Drinking Water

2:00 pm   *Panel:*

- **Wellbore Integrity: Failure Mechanisms, Historical Record, and Rate Analysis** ....*Anthony Ingraffea,*
Cornell University

- **eWCAT (electronic Well Control Assurance Tool) and Process Safety** .... *Marco op de Weegh,*
Shell Exploration & Production Company

- **Well Integrity and Long-Term Well Performance Assessment** .... *Bill Carey,*
Los Alamos National Laboratory

- **Open Questions Regarding Well Construction and Hydraulic Fracturing** .... *Courtney Hemenway,*
Hemenway Groundwater Engineering, Inc.

Questions of Clarification

Break (10 minutes)

Facilitated discussion among workshop participants focusing on key questions:

- What testing is conducted to verify issues do not exist prior to, during and after hydraulic fracturing?

- What testing or monitoring techniques ensure adequate confinement?

- What is the breadth of approaches?

4:45 pm   **Summary of Session 2** .... *Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

4:55 pm   **Closing Remarks**.. *Ramona Trovato, US EPA*

5:00 pm   **Adjourn**

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April 17: Subsurface Modeling

8:30 am **Introduction to Day Two** .... *Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

Session 3: Subsurface Modeling of Fluid Migration to Identify and Understand Potential Impact on Aquifers

8:35 am *Panel:*

- **Evaluating Scenarios of Potential Subsurface Impact Using Computational Models** .... *Stephen Kraemer,*
US EPA

- **Analysis of Feasibility of Extensive Fracture Development and Fault Activation Induced by Hydraulic Fracturing** .... *George Moridis,*
Lawrence Berkeley National Laboratory

- **Modeling of Leakage in Potential Failure Scenarios in Shale Gas Systems** .... *George Moridis,*
Lawrence Berkeley National Laboratory

- **Emergence of Delamination Fractures around the Casing During Wellbore Stimulation** ....*Arash Dahi Taleghani,*
Louisiana State University

- **Abandoned Wells as Potential Leakage Pathways: Lessons Learned from CO_2 Geological Storage**.. *Michael Celia,*
Princeton University

Questions of Clarification

Break (10 minutes)

Facilitated discussion among workshop participants focusing on key questions:

- *What additional potential failure scenarios not covered in the EPA study progress report should be investigated?*

- *What are the most important parameters and appropriate level of complexity for a model that studies the severity of the potential impact of hydraulic fracturing on drinking water resources?*

- *What are the advantages and disadvantages of different modeling approaches?*

- *What well performance data (e.g., microseismic testing, pressure, tracer or other) are available to EPA that would be useful to build and evaluate the model?*

12:15 pm **Summary of Session 3** ....*Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

12:25 pm **Closing Remarks** ....*Glenn Paulson, US EPA*

12:30 pm **Adjourn**

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Poster Session

Well Design and Construction in Texas
Travis Baer, Railroad Commission of Texas

Colorado's Regulations on Wellbore Integrity and Hydraulic Fracturing
Stuart Ellsworth, CO Oil and Gas Conservation Commission

Simple Groundwater Modeling of Transport Pathways in Unconventional Natural Gas Plays
Tom Myers, Great Basin Hydrology

Long Term Risk of Potable Aquifer Contamination via Fracking Fluids
George Pinder, University of Vermont

Nonisothermal Multiphase Multicomponent Reactive Transport in a Deforming Fractured Porous Media
Robert Podgorney, Idaho National Laboratory

Modeling Near Wellbore Leakage Pathways in Shale Gas Wells: Investigating Short and Long Terms Wellbore Integrity
Saeed Salehi, University of Louisiana at Lafayette

Technical Follow-up Discussion on Subsurface Modeling
June 3, 2013

US EPA Conference Center at One Potomac Yards
Arlington, VA

June 3:

8:00 am   Registration/Check-in

8:30 am   **Welcome and Introductions** ....*Ramona Trovato, US EPA*
Glenn Paulson, Science Advisor, US EPA

8:40 am   **Purpose of Discussion** ....*Workshop Co-Chairs:*
Jennifer Orme-Zavaleta, US EPA
Kris Nygaard, ExxonMobil Production Company

8:50 am   **Session 1: Subsurface Scenarios: What are we trying to model?** *... Stephen Kraemer,*
US EPA
George Moridis, Lawrence Berkeley National Laboratory

Presentation and discussion with participants:
- Review the subsurface scenarios under study
- How, why did EPA select the current set of modeling scenarios?
- What are the explicit and implicit scenario assumptions?
- What pros and cons of the scenarios do the participants see?
- What other, different scenarios would participants recommend we consider?
- What scenarios does industry typically model?

10:30   Break

10:45 am   **Session 2: Modeling Subsurface Scenarios: How do we do this?** *...... George Moridis,*
Lawrence Berkeley National Laboratory

Presentation and discussion with participants:
- Review the TOUGH+ code: grid generation, force modeling
- Explicit and implicit modeling assumptions
- History, applications of code in other settings (Yucca, CO_2 sequestration, other)
- Linkages back to the scenarios under study
- Are there different models/approaches EPA should consider?
- How does industry conduct modeling to address subsurface scenarios?

12:00 pm   Lunch

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1:00 pm   **Continue Session 2: Modeling Subsurface Scenarios:**
             How do we do this? .... *George Moridis,*
                                                          Lawrence Berkeley National Laboratory

             Discussion with participants

3:00 pm   Break

3:10 pm   **Wrap-up and Summarize Main Discussion Points**

4:00 pm   Adjourn

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List of Meeting Participants

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Travis Baer
Railroad Commission of Texas

Karl Bandilla
Princeton University

William Bates
US EPA Region 5

Timothy Beard
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John Bolakas
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Richard Boone
O'Brien & Gere

Jeanne Briskin*
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Bill Carey*
Los Alamos National Laboratory

Michael Celia*
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Arash Dahi Taleghani*
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Tim Ellison
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Stuart Ellsworth
*Colorado Oil and Gas Conservation
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WPX Energy

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Aramco Services Company

Susan Harvey
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Cornell University

Stephen Kraemer*
*US EPA ORD/National Exposure Research
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Chitra Kumar
*US EPA Office of Water/Office of Ground
Water and Drinking Water*

Marty Link
*Nebraska Department of Environmental
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Theodore Loukides
*New York State Department of
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Thomas Myers
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Karen Olson
Southwestern Energy Company

Marco op de Weegh*
Shell Exploration & Production Company

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D. Steven Tipton*
Newfield Exploration Company

Thomas Tomastik
Ohio Department of Natural Resources

Ramona Trovato
*US EPA Office of Research and
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Norman Warpinski
Pinnacle – A Halliburton Service

John Williams*
U.S. Geological Survey

Lloyd Wilson
New York State Department of Health

Nathan Wiser*
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* Presenter

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List of Meeting Participants

Technical Follow-up Discussion on Subsurface Modeling Attendees

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Introduction

At the request of Congress, the U.S. Environmental Protection Agency (EPA) is conducting a study to better understand the potential impacts of hydraulic fracturing on drinking water resources. The scope of the research includes the full cycle of water associated with hydraulic fracturing activities. In the study, each stage of the water cycle is associated with a primary research question:

- **Water acquisition:** What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?

- **Chemical mixing:** What are the possible impacts of hydraulic fracturing fluid surface spills on or near well pads on drinking water resources?

- **Well injection:** What are the possible impacts of the injection and fracturing process on drinking water resources?

- **Flowback and produced water:** What are the possible impacts of surface spills on or near well pads of flowback and produced water on drinking water resources?

- **Wastewater treatment and waste disposal:** What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

In 2013, EPA hosted a series of five technical workshops related to its *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The five technical workshops included Analytical Chemical Methods (February 25, 2013), Well Construction/Operation and Subsurface Modeling (April 16–17, 2013), Wastewater Treatment and Related Modeling (April 18, 2013), Water Acquisition Modeling (June 4, 2013) and Hydraulic Fracturing Case Studies. The workshops were intended to inform EPA on subjects integral to enhancing the overall hydraulic fracturing study, increasing collaborative opportunities and identifying additional possible future research areas. Each workshop addressed subject matter directly related to the primary research questions.

For each workshop, EPA invited experts with significant relevant and current technical experience. Each workshop consisted of invited presentations followed by a facilitated discussion among all invited experts. Participants were chosen with the goal of maintaining balanced viewpoints from a diverse set of stakeholder groups including industry; nongovernmental organizations; federal, state and local government agencies; tribes; and the academic community.

The third workshop, Well Construction/Operation and Subsurface Modeling, was held on April 16–17, 2013. The workshop was co-chaired by Dr. Jennifer Orme-Zavaleta (Director, EPA National Exposure Research Laboratory) and Dr. Kris Nygaard, ExxonMobil Production Company. A morning session on April 16th addressed *Well Design and Construction to Protect Drinking Water*, an afternoon session on April 16th focused on *Well Operation and Monitoring to Protect Drinking Water,* and a third session on April 17th addressed *Subsurface Modeling.* In

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addition, several experts shared technical knowledge during a poster session (Appendix C). A technical follow-up discussion on *Subsurface Modeling* was held on June 3, 2013.

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Summary of Presentations for Session 1:
Well Design and Construction to Protect Drinking Water

Workshop facilitator **Susan Hazen,** Hazen Consulting and Support Services, welcomed participants and discussed ground rules. She noted that the meeting was not being held under the rules of the Federal Advisory Committee Act (FACA); rather, EPA was looking for the individual input and insights of participants.

Ramona Trovato, Associate Assistant Administrator for EPA's Office of Research and Development (ORD), briefly described the study being led by ORD. She expressed appreciation for the input, expertise and time that participants would be contributing during the workshop. She noted that the five technical roundtables held in November 2012[1] would be followed with five more roundtables after the technical workshops are completed, and that EPA was also holding webinars after each technical workshop.

Dr. Glenn Paulson, Science Advisor to the Acting EPA Administrator, welcomed the participants and stated that an important goal of the workshop was to help EPA communicate with people in the field. He noted that the participants brought several hundred years' worth of diverse expertise among them, with close to a century of experience from EPA participants.

Dr. Jennifer Orme-Zavaleta, Director of EPA's National Exposure Research Laboratory, described the flow of the conversation that would take place over the two days of the workshop. The presentations and discussions would move from well design and construction, to operation and monitoring, to subsurface modeling. She noted that these topics had been identified during roundtable discussions with stakeholders to help address some of technical challenges of the drinking water study. She noted the goal of attaining energy security while protecting resources, and emphasized the value of frank and candid sharing of perspectives on the workshop topics.

Dr. Kris Nygaard, ExxonMobil Production Company, provided opening remarks from industry's perspective. He posited the following keys to success in unconventional oil and gas activities: managing risk; managing uncertainties to account for extremely complex subsurface environments; generating opportunities in the areas of energy security, job and revenue growth, and emissions reductions; and promoting collaboration among industry, stakeholders and regulators. He stated the goal of building relationships during the workshop and urged participants to listen to and learn from all stakeholders present. Industry, he said, desires scientifically sound discussions with appropriate context and a common frame of reference to discuss the issues.

Jeanne Briskin and **Nathan Wiser,** EPA, described EPA's proposed analysis from well file review. Ms. Briskin noted that the overall goals for EPA's study are to assess whether hydraulic fracturing may impact drinking water resources, and to identify factors driving the severity and

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[1] See *Summary of Technical Roundtables on EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (http://www2.epa.gov/sites/production/files/documents/summary-of-technical-roundtables.pdf).

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frequency of impacts. For the well injection stage of the hydraulic fracturing water cycle, EPA's secondary research questions are:

- How effective are current well construction practices at containing gasses and fluids before, during and after fracturing?

- Can subsurface migration of fluids or gases to drinking water resources occur, and what local geologic or man-made features might allow this?

Mr. Wiser described the well file review that EPA was conducting to identify practices or factors that may impact drinking water resources. A statistically representative sample of wells was chosen from nine oil and gas operating companies of various sizes, including different geographic areas and completion types. Mr. Wiser described proposed graphs for data from the well file review. These graphs—chosen for their potential to show factors that increase the possibility of drinking water impacts—included vertical separation between the hydraulic fracturing zone and the ground surface, vertical separation between the hydraulic fracturing zone and the top of the cement behind the casing being used for hydraulic fracturing, distribution of cement bond indices calculated from cement bond logs, zones and degree of cement, and distance to nearby faults. Other factors of interest were also presented.

John Williams, U.S. Geological Survey (USGS), discussed geophysical logging to characterize fresh and saline water flow zones in the fractured bedrock of the Northern Appalachian Basin. He stated that historically, shallow systems have not been well characterized. He noted that petrophysical logging is effective for estimating formation water resistivity at some sites but not others. USGS has developed an integrated geophysical logging approach that includes collection of fluid property and video logs and flow metering under ambient and pumped conditions, in addition to the petrophysical logging suite. This approach was applied at a deep borehole site in a bedrock upland setting in north-central Pennsylvania. Mr. Williams stated that the integrated geophysical logging approach would be beneficial for the design and installation of discrete-zone monitoring at multi-well pads, and for the investigation of domestic water supply wells that might be impacted by shale gas development.

Talib Syed, TSA, Inc., presented an overview of well construction and well integrity related to hydraulically fractured wells. He stated that the two most critical considerations for well construction are casing design and cement design. He presented casing design criteria to account for tensile forces; collapse pressure; burst pressure; compression load; and buckling, piston and thermal effects. He discussed cement evaluation, including factors that affect cement log quality, and presented key components of cement design and zonal isolation. He noted the importance of isolating potential flow zones in uphole sections of the well when designing cement slurries and implementing a cement job. He presented a number of best practices and recommendations for maintaining well integrity for hydraulically fractured wells, not just during drilling but throughout a well's life cycle.

Steven Tipton, Newfield Exploration Company, presented an overview of oil and gas well cementing. He noted that cementing is one of the most critical steps in drilling and completion, requiring the application of many different scientific and engineering disciplines. He presented the objectives of primary cementing, and discussed the importance of developing a plan to take

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the well from drilling though plugging before the initial cement program is designed. He then discussed best practices for achieving effective primary cementing and the fundamentals of cement placement. He described how zonal isolation for each well must be designed and constructed, taking into account the well's unique geological environment. Mr. Tipton described the benefits of pipe rotation and reciprocation (up and down motion) during cementing, showing a computer simulation of cementing with and without rotation and reciprocation. He discussed pressure testing and operational evaluation to verify barriers, noting that no direct measurement is available to verify a cement barrier behind casing.

Anthony Badalamenti, Halliburton, discussed zonal isolation methods for ground water aquifer protection. He provided an overview of oil well cementing, noting that its purposes are to restrict fluid movement between formations and to bond and support casing. He discussed typical cement job design challenges, noting that information is needed on such factors as well geology, reservoir temperature and pressure, and casing design. The cement job design, he said, needs to take the well not just through construction but through its entire life cycle. He discussed cement job planning and fluid system design (using computer simulations and laboratory testing), steps to prepare the wellbore to receive cement, and post-job cement evaluation methods.

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Summary of Discussions Following Session 1:
Well Design and Construction to Protect Drinking Water

Following questions for clarification, participants were asked to consider four questions for discussion:

- What current techniques are designed to prevent leaks through production well tubulars and fluid movement along the wellbore?

- What factors are typically used to ensure adequate confinement of fluids that can move?

- How are ground water resources identified and documented prior to and during production well installation?

- What is the breadth of approaches?

Not all industry representatives present responded to each of these questions.

Key themes from Session 1 discussion:

Pressure monitoring. A number of participants discussed the use of pressure testing during both well preparation and hydraulic fracturing. One participant stated that any pressure on an annulus (the annulus between the production and next innermost casing) not related to reservoir conditions indicates that some type of failure may have occurred, necessitating an immediate shutdown of the fracturing operation to determine the cause and remediate. It was noted that if there is well failure, the operator has to reestablish primary barriers to meet or exceed. Several participants noted conditions that can cause annular pressure not related to well integrity, such as tubular expansion that compresses fluid or expansion due to temperature. One participant stated that stray gas migration, rather than fluid movement, is the issue in annulus pressurization. Several participants noted that while some states have requirements for reporting annular pressure, guidance to help operators interpret pressure changes could be useful.

In response to a question about how much of an injection pressure drop (or how much annular pressure rise) would lead to a shutdown, a participant stated that the primary goal is to stimulate the producing formation, and the pressure differs from reservoir to reservoir and from well to well. If there is a loss of injection pressure due to not pumping into the reservoir, it is usually an immediate, large drop (e.g., 100 percent). A participant described an example of a catastrophic failure in which poor-quality tubing split during pressure testing, before fluid was pumped.

Several participants raised questions about whether there are any more subtle, sub-catastrophic signals that could indicate a need to modify operations (short of shutdown), and whether another monitoring method might be needed to address potential migration through geology. Another participant stated that if a subtle change in monitored pressure cannot be explained, it will cause the operator to shut down and ensure containment.

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One participant noted that understanding annular and production casing pressure requires knowledge of local conditions; for example, in some formations, the injection pressure into the production casing may cause the pressure to drop significantly during hydraulic fracturing and then recover. One participant said that there might be a several-thousand-pound pressure difference between the production casing and the annulus during hydraulic fracturing, and someone on site with experience can observe whether a failure has occurred. Another participant stated that pre-job fracture growth modeling is a best practice, to help operators recognize deviations during hydraulic fracturing, as well as to allow comparison with post-hydraulic fracturing data.

It was also noted by one participant that fluid monitoring is very expensive. Corrosion monitoring may be useful to indicate potential problems.

Diagnostics to assess well integrity. Several participants suggested a systematic approach to evaluating well condition. A participant noted the importance of understanding the current condition of older wells. Because few regulations address this, companies use their own tools and procedures to investigate the appropriateness of hydraulically fracturing older wells (e.g., running mechanical inspection logs, caliper logs, sonic and/or magnetic flux tools to look at casing condition, and pressure-testing the casing).

Well life cycle. It was stated that ensuring a good surface protection string before hydraulic fracturing is critical; then, if operators monitor appropriately throughout production (e.g., for corrosion in the production string), they will see a problem before it becomes a serious issue. A participant noted that a well often is subjected to multiple pressure changes throughout its lifespan and operators need to plan for this when designing the well.

Cementing. Several participants commented on the role of cementing programs in ensuring confinement, noting that cement mechanics is an important subject for unconventional wells. A participant noted that for the primary cement job, there can be different criteria for the cement slurry for each well. One participant stated that if an intermediate casing string is added to protect water, then cementing needs to come all the way to the surface. Several participants mentioned that full cementing of annular spaces can be a means to enhance barrier functioning, but that cement displaced to the surface eliminates the potential to monitor annular pressure for insights into well condition during operations. A participant stated that if monitoring the annular pressure results in detecting a leak whose remediation involves cementing that annulus, one could reason that the annulus should have been cemented from the start. Regarding re-fracturing in a new zone, a participant stated that companies examine the initial completion and try to ensure zonal isolation in order to recomplete.

Several participants discussed cement bond log evaluation, mentioning limits associated with potentially subjective interpretations surrounding bond log calculations. One participant stated that wells cemented with foamed cement formulations are extremely difficult to evaluate with cement bond logs using existing technology.

Alternative technologies. A participant noted that in addition to current techniques and traditional cements, it was important to consider emerging and future technologies—for

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example, high-strength resin used for cementing operations. It was stated that high-strength resin can get into small fractures and is not affected by water, acids or bases.

Definition of protected water. Several participants described state programs and standards for identifying ground water resources. Some participants asked how "useable ground water" is defined, and suggested a need for consistency across state and federal jurisdictions for protected water.

Industry practices to identify ground water resources. One participant stated that his company conducts a robust petrophysical evaluation to document ground water. Several industry participants indicated that they have a dialogue with regulators and local geologists to determine where ground water resources are, and verify that information and water quality by sampling and logging. A participant said that best practices for identifying water resources include examining operator data and water resources board data; if these data are not adequate, then the operator needs to get a resistivity log to verify water quality at the location.

Variability in water quality. A participant stated that Pennsylvania has a wide variation in water quality, including seasonal variations, and a preponderance of naturally occurring methane in ground water. He said that industry is aggressively trying to understand baseline of water quality where they operate.

Need for better data. A number of participants said that there is a lack of ground water data in many locations and stated the importance of establishing a better database of water quality. A participant noted that most states have a repository of water data, which usually include water well drilling records. He said that the records may contain information on physical location, depth, shallowest depths and some lithology, but the data quality is highly variable, and the data are often limited. For this reason, it is difficult to conduct baseline studies of water quality. One participant said that current thinking in New York State is that several years of ground water baseline monitoring are needed before drilling.

Collaboration between industry and regulators. Several participants noted that sharing of data between industry and regulators would be mutually beneficial. Several industry participants expressed a desire to share data with regulators.

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Summary of Presentations for Session 2:
Well Operation and Monitoring to Protect Drinking Water

Dr. Anthony Ingraffea, Cornell University, discussed the historical record on loss of wellbore integrity, defined as persistent annulus pressure, and the implications for impacts on underground sources of drinking water. To provide context, he presented industry-reported data on loss of wellbore integrity in both offshore and onshore wells, stating that loss of wellbore integrity is a documented and chronic problem that tends to increase with well age. He then presented results of an analysis of leaking wells in the Pennsylvania Marcellus play based on annulus pressure-related violations issued and inspection reports by the Pennsylvania Department of Environmental Protection. The results showed failure consistent with previous industry data: normalized with respect to new wells drilled in 2010, 2011 and 2012, 6.9, 7.2 and 8.9 percent, respectively, have persistent annulus pressure or other related violations. He stated that not all leaking wells are issued violations, so the actual figures could be higher. He also stated that leaks do not necessarily mean impacts to drinking water, but, any one leaking well, under the right conditions, could impact multiple water wells. He stated that methane is prevalent in Pennsylvania water wells, but at very low levels, and there is a pressing need for scientific investigation of the relationship between loss of well bore integrity and hydrocarbon contamination of water wells.

Marco op de Weegh, Shell Exploration and Production Company, described Shell's electronic well control assurance (eWCAT) and process safety in wells. The company uses a health, safety, security, environment and social performance framework that provides standards and supporting documents to meet accountability and assurance requirements. eWCAT was implemented within this framework to verify compliance and make integrity efforts transparent. Mr. op de Weegh described a well delivery process and "bow-tie" methodology that assesses hazards and consequences of events that indicate major risk exposures, looking over the whole life cycle of a well. He also described a casing and tubing design manual, one of the tools in eWCAT, which provides requirements for a barrier policy and the design process. He stated that redundant and verified barriers during all phases of well construction and operations are an integrated requirement within the organization.

Dr. William Carey, Los Alamos National Laboratory, discussed well integrity and long-term well performance assessment using insights from work on carbon sequestration. He described potential communication pathways associated with degradation of barriers and barrier interfaces. He stated that some wellbore systems could be susceptible to flow at interfaces (cement-steel, cement-caprock and cement fractures). He noted that Portland cement has been found to have some degree of self-limiting permeability at interfaces, related to mineral precipitation at interfaces and potentially plastic deformation. Cement deforms plastically at elevated depths, and its geomechanical behavior is critical to assessing potential damage. Dr. Carey stated that cement protects steel from corrosion, and steel corrosion can be more rapid than cement degradation. He discussed the need for coupled mechanical and hydrological field observations, experiments and models to better understand threats to zonal isolation.

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Courtney Hemenway, Hemenway Groundwater Engineering, Inc., presented "open questions" about well construction and hydraulic fracturing. He described the process of hydraulic fracturing, and stated that the term "fracturing" is often incorrectly used when discussing well drilling, construction and production. In his view, there has been no direct correlation between ground water contamination and hydraulic fracturing; rather, contamination has been associated with improper well construction or lack of control of fluids at the surface. Mr. Hemenway presented a number of questions to guide future research on potential impacts from hydraulically fractured wells.

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Summary of Discussions Following Session 2:
Well Operation and Monitoring to Protect Drinking Water

Following questions for clarification, participants were asked to consider three questions for discussion:

- What testing is conducted to verify issues do not exist prior to, during and after hydraulic fracturing?

- What testing or monitoring techniques ensure adequate confinement?

- What is the breadth of approaches?

Not all industry representatives present responded to each of these questions.

Key themes from Session 2 discussion:

Testing to verify that issues do not exist. One participant described his company's well pad evaluation program, which includes baseline sampling of nearby water wells, collecting remote sensing data for all human health and environmental receptors (houses, barns, churches, etc.), and gathering information on abandoned wells and any evidence of preexisting faults. Another participant discussed pressure testing of the casing to ensure barriers are effectively placed. Several participants discussed collection of subsurface data to determine baseline water quality. Specific analytes mentioned included selenium; barium; methane; benzene, toluene, ethylbenzene and xylenes; metals; total dissolved solids; and all contaminants with drinking water maximum contaminant levels. A participant noted that many operators perform diagnostic fracture injection tests (DFIT) to determine reservoir pressure and formation permeability, and raised the question of how to model a fault that might breach through barriers. An EPA participant noted that the well file review results locating faults near hydraulic fracturing operations would not indicate transmissivity of the faults.

A participant mentioned a water database set up through Indiana University of Pennsylvania. In the participant's view, there are some issues about providing water quality data while protecting privacy rights of landowners, but the data could be made granular for use by industry, scientists, educators and the public. A participant mentioned the Marcellus Shale Coalition, whose website is a repository of recommended practices, pre- and post-hydraulic fracturing sampling, and a well pad evaluation tool.

A participant raised the issue of how to define a statistically representative environmental sample, and how to define the ambient water quality to be protected. He noted that there can be significant variability in individual wells (e.g., from rain/snowfall or barometric changes). Another participant noted that his company does baseline historical research of water well drilling at the county courthouse.

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Testing/monitoring techniques to ensure adequate confinement. One participant noted that especially in new areas, her company takes cores, does rock mechanics testing and performs DFITs. The participant stated the need to validate models, use the best data and build models for every play, typically containing a thousand model layers. She also described the use of radioactive tracers added to the tail end of fracturing treatments to identify vertical fracture growth. She mentioned that there can be wells completed with multiple horizontal lateral wellbores after the vertical part of a well is completed. Another participant noted that his company takes cores through the target interval and overlying intervals, and runs laboratory tests on K_v/K_h (vertical vs. horizontal permeability).

In discussing the use of cement bond logs, another participant stated that significant differences in cement bond logging have not been seen before and after hydraulic fracturing (e.g., if re-fracturing).

A participant noted that some operators do baseline sampling using drinking water wells, which are not designed to evaluate transport of constituents of ground water along specific flow paths. He suggested installing ground water monitoring wells to obtain four quarters of seasonal data, pressure monitors above fractured areas, and microseismic monitoring during hydraulic fracturing. A participant stated that microseismic monitoring may not be a good indicator of fracturing, because there can be both aseismic fracturing and detectable microseisms not physically linked to fracture growth. Another participant questioned the use of ground water monitoring wells, stating that those wells are for monitoring things not related to hydraulic fracturing.

Several participants raised the need for a systematic approach to sampling and quality control/quality assurance. A participant stated that key to monitoring and sampling are who does it and how it is done, noting that erroneous data can lead to erroneous conclusions.

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Summary of Presentations for Session 3:
Subsurface Modeling

Dr. Stephen Kraemer, EPA, presented an overview of the use of computational models to evaluate scenarios of potential subsurface impact from well injection and fracturing processes. Subsurface scenario modeling can help answer EPA's secondary research question, "Can subsurface migration of fluids to drinking water resources occur, and what local geological or man-made features might allow this?" He described the interagency agreement between EPA and Lawrence Berkeley National Laboratory (LBNL) to undertake modeling work. For scenarios of potential subsurface impact from pathways including production wells, induced fractures, faults and offset wells, geomechanics and flow and transport models can identify factors influencing geophysical likelihood of the pathway and potential for fluid migration. Dr. Kraemer described criteria for model selection (e.g., appropriate complexity, appropriate transparency and acceptance) leading to selection of the TOUGH+ (Transport of Unsaturated Groundwater and Heat) family of codes.

Dr. George Moridis, LBNL, described research underway to develop modeling simulations to evaluate the possibility that hydraulic fracturing operations can result in: 1) fractures that extend from the shale gas reservoir through the overburden to a shallow aquifer, thus creating a fast permeability pathway that can result in aquifer contamination; and 2) significant reactivation of dormant faults, creating substantial displacement and pathways for fast transport of contaminants from the shale reservoir to shallow ground water resources. The research is looking at fracture propagation in the case of typical Marcellus shale gas reservoirs, using peer-reviewed data with an algorithm that describes fully coupled three-dimensional flow, thermal and geomechanical processes. The modeling uses the dynamic multi-continuum approach, determines simultaneous tensile and shear failure, and estimates leak-off to the reservoir formation. Some early results from this work suggest that estimation of the fracture volume based on the injection volume may significantly underestimate the fracture volume and fracture propagation.

Dr. George Moridis (presenting for **Dr. Matt Freeman,** LBNL) described modeling of leakage in potential failure scenarios in shale gas systems. This research is addressing the question—of the potential for fluid migration (assuming that artificial or natural pathways exist). The researchers are using the TOUGH+RealGasH2O code to model the two-phase flow of shale gas and water systems, along with a mesh-building tool to capture the potentially complex geometries where thin vertically extensive features intersect multiple geologic strata. These tools are being applied to model various configurations of the fractured system, using a sensitivity analysis approach. Sensitivity parameters include conductivity of the leaking pathway, production rate from the water well and the shale well, permeability of the shale, and vertical distances between layers. Early results suggest that gas leakage rate is substantially controlled by conductivity of the leaking pathway, relative pressure regimes in the shale reservoir and aquifer, and shale matrix permeability. Dr. Moridis also described plans for improving the model.

Dr. Arash Dahi-Taleghani, Louisiana State University, discussed the potential risk of delamination fractures in the cement sheath around the casing that may form during wellbore stimulation and provide hydraulic communication with shallower zones. He stated that the

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current approach for modeling cement behavior (i.e., modeling interfacial strength only) is too simplistic to identify effects leading to failure. He presented a more complex constitutive equation to model the behavior of cement interfaces. He stated that this equation, coupled with the classical loading test, leads to determination of cohesive parameters to predict the mechanical behavior of cement interfaces. This approach, he said, can be applied to other issues such as well leakage in abandoned wells or CO_2 sequestration.

Dr. Michael Celia, Princeton University, discussed modeling to estimate potential leakage from CO_2 geological storage that might inform the study of potential leakage of fluids associated with unconventional oil and gas production. Because of high uncertainties associated with the location and hydraulic characteristics of abandoned wells, he said, Monte Carlo calculations and simplified modeling approaches are needed. Dr. Celia described the development of a semi-analytical model to evaluate potential leakage rates, and discussed field measurements to determine the effective permeability of the cement sheath in nine older wells to better characterize the potential flow parameters. While there are only a few data points, the estimates of CO_2 and brine leakage appear to be acceptably low for CO_2 injection wells. Dr. Celia stated that some components of the kinds of models he had described may be useful for hydraulic fracturing risk assessment studies.

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Summary of Discussions Following Session 3:
Subsurface Modeling

Following questions for clarification, participants were asked to consider the following questions for discussion:

- What additional potential failure scenarios not covered in the EPA study progress report should be investigated?

- What are the most important parameters and appropriate level of complexity for a model that studies the severity of the potential impact of hydraulic fracturing on drinking water resources?

- What are the advantages and disadvantages of different modeling approaches?

- What well performance data (e.g., microseismic testing, pressure, tracer or other) are available to EPA that would be useful to build and evaluate the model?

Not all industry representatives present responded to each of these questions.

Key themes from Session 3 discussion:

Other potential failure scenarios. One participant stated that many potential scenarios could be developed, but recommended that EPA look at the likelihood or probability of the scenario and drinking water impacts, stating that there is an inherently high degree of uncertainty in parameterization in a deterministic approach. A participant expressed agreement with a probabilistic approach, but stated some people desire zero probability of a failure.

A participant stated that while much attention is focused on new well construction, it is important to look at the integrity of existing wells (e.g., those being re-fractured), because they may have been designed and constructed using less sophisticated technology or information, or may simply be in a state of deterioration.

A participant suggested a collaboration to look at logs in the Marcellus and model different layers, stating that a good correlation is needed between leak-off and permeability. The participant also suggested running a base case without hydraulic fracturing for 100 years, to see if hydrocarbons remain static. The participant asked that U.S. oil field units be used in presenting model results (psi, feet, bbl, etc.) rather than metric units.

One participant recommended looking at a "no failure" scenario because the wells are engineered not to fail. Another participant suggested applying modeling to actual incidents where a failure has occurred.

Key model parameters and appropriate level of complexity. It was noted that the more complicated the model, the more difficult it is to quantify uncertainty; a simple model may not adequately capture essential processes. A decision needs to be made about the appropriate level

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of model complexity. A participant stated that all models have uncertain inputs that need to be quantified, and the impact of this parameter uncertainty on the results must also be quantified. A participant recommended careful experimental design with input from industry and academia to properly frame the model and define uncertainties for key parameters (for example, drawing on decades of research on fault transmissibility) and a probabilistic approach to help scope the modeling effort.

A number of participants noted that industry data would be helpful in quantifying uncertainty. A participant stated that industry may not have any data on a particular scenario, and recommended that EPA provide specifics about areas in which data are needed to calibrate models.

Individual participants provided the following suggestions for consideration:

- Detailed descriptions of fault deformations.
- Measurements of permeability changes.
- The conductivity value of debonded or delaminated concrete.
- Realistic parameters for the reservoirs that industry is dealing with, including layering, permeability ratios horizontal to vertical (K_v/K_h), natural fracturing and stress numbers.
- Attenuation of fracturing fluid constituents.
- The fluid system and proppant transport.
- Heterogeneity of mechanical properties.
- Multiphase pressure drops in a fracture.
- Distance from adjacent wells.
- Parameterization of up to 1,000 layers.
- Spatial and temporal resolution (i.e., long-term evolution of the created fracture).
- Wettability of rock.
- Regional variations.

Advantages and disadvantages of the different modeling approaches. It was noted that models have to have appropriate complexity to represent the essence of geophysical processes and geological heterogeneities. Complex solution procedures may introduce numerical errors, so it is important to check against exact analytical solutions. One participant suggested taking the same input and conceptual setup and doing a model comparison, or benchmarking exercise if one of the codes is well accepted. Another participant recommended clear documentation of input parameters for different cases. A participant noted that tools for uncertainty-based models exist in hydrological science, such as the Kalmann filter.

A participant also recommended considering numerical approaches, saying that once fracturing begins, continuum-based approaches do not work as well. It was also suggested to pay attention to the practicality of the model.

A peer review process for the model was recommended that engages government, industry and academia. It was suggested that appropriate journals be selected to ensure review by people who know the technology.

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Available well performance data. One participant suggested looking at recent conductivity testing data for Barnett shale from Texas A&M University. The Department of Energy Multiwell Experiment (MWX) study was suggested as an excellent source of data on well performance, as was a study by Anadarko on fault properties. It was noted that data from the nine companies in the well file review are still being analyzed; one complexity is the degree to which information is claimed as confidential. A participant suggested the idea of getting data through a neutral party, generalized enough not to be identifiable.

A participant stated the importance of validating data on impacts. Finally, it was noted that industry collects data for specific business decisions, so it is rare to have integrated data sets from a common pedigree needed to capture appropriate bounds for models.

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Concluding Remarks

Ramona Trovato and Dr. Glenn Paulson, EPA, thanked the participants for bringing their knowledge, expertise and passion to the workshop presentations, posters and discussions. Ms. Trovato encouraged the participants to submit data and scientific literature to inform the current drinking water resources study, as described in the November 5, 2012, *Federal Register* notice (see http://www.regulations.gov, Docket ID No. EPA-HQ-ORD-2010-0674). She stated that EPA hopes to see the participants at future stakeholder meetings and activities. This collaborative effort, she stated, will help ensure environmental health and safety so that the nation can realize the opportunities for energy security and economic health that unconventional oil and gas extraction can provide.

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Subsurface Modeling Technical Follow-up Discussion

A technical follow-up discussion on subsurface modeling was held on June 3, 2013. Susan Hazen opened the workshop, reminding participants that the meeting was not being held under the FACA rules, but was designed to obtain the individual input and insights of participants. Ramona Trovato, EPA, and Dr. Glenn Paulson, EPA, welcomed the participants and expressed appreciation for their time, attention and expertise. Workshop co-chairs Dr. Jennifer Orme-Zavaleta, EPA, and Dr. Kris Nygaard, ExxonMobil Production Company, noted that participants at the April 17th workshop had expressed a desire for more detail and transparency about how EPA is approaching subsurface modeling, and that sharing perspectives from all stakeholder groups is crucial to EPA's drinking water study.

Follow-up Session 1 Presentation: "Subsurface Scenarios: What Are We Trying to Model?"
Stephen Kraemer, EPA, and Dr. George Moridis, Lawrence Berkeley National Laboratory

Dr. Stephen Kraemer presented and answered technical questions on the subsurface scenarios under study, how and why EPA chose the current set of modeling scenarios, and the explicit and implicit assumptions in the modeling scenarios. He reviewed the secondary research question that is the focus of the modeling effort: "Can subsurface migration of fluids (gases, liquids) to drinking water resources occur, and what local geologic features might allow this?" Based on literature review, interviews with experts and empirical data, EPA identified several hypothetical failure scenarios of high interest to stakeholders. EPA is using coupled geomechanical flow and transport numerical models to identify 1) factors influencing the geophysical likelihood of the pathway and, concurrently, 2) factors influencing fluid migration and potential impact on the drinking water aquifer in the event of a pathway. Dr. Kraemer noted that the modeling effort is not a comprehensive probabilistic risk assessment, but a scoping impact assessment. For each hypothetical potential failure scenario, EPA is trying to understand combinations of parameters that result in impact or no impact to drinking water aquifers.

Dr. Kraemer reviewed the criteria for model selection, including the need to keep models as simple as possible, but complex enough to capture the essence of what is occurring in the subsurface. He then discussed conceptual models for the five hypothetical failure scenarios:

- Scenario A: Potential migration along the production wellbore.

- Scenario B: Hydraulic fracture growth upward toward an aquifer, where the shale reservoir and aquifer are separated by a non-hydrocarbon-bearing formation.

- Scenario C: Hydraulic fracture growth upward toward an aquifer, where the shale reservoir and aquifer are separated by a hydrocarbon-bearing formation.

- Scenario D: Hydraulic fracture growth upward toward a fault connected to an aquifer and separated by a hydrocarbon-bearing formation.

- Scenario E: Hydraulic fracture growth toward an old (e.g., abandoned) well.

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The flow properties for different zones (shale, overburden, aquifer, fracture, open wellbore, conventional oil/gas reservoir and fault) and geomechanical property sets used in the study were also shown.

Dr. Kraemer provided an overview of the publication plan for this aspect of the drinking water study. Modeling results will be published in peer-reviewed journals. Two articles have already been published, and another eight have been accepted or are in preparation. Paper topics include modeling foundations, physics of the pathways and assessment of impact. A paper describing the modeling approach is described at http://dx.doi.org/10.1016/j.cageo.2013.04.023; a paper describing potential fault reactivation from hydraulic fracturing is described at http://dx.doi.org/10.1016/j.petrol.2013.04.023. The plan is to submit at least eight additional publications to journals by December 31, 2013.

Follow-up Session 2 Presentation: "Modeling Subsurface Scenarios: How Do We Do This?"
Dr. George Moridis, Lawrence Berkeley National Laboratory

Dr. Moridis presented and answered technical questions on the TOUGH+ code, modeling assumptions, applications of the code in other settings, and modeling of the scenarios under study. He reviewed the two questions addressed in the overall modeling approach: 1) Are the geomechanical failure (and fracture propagation) scenarios physically possible? 2) If a fast transport pathway between the shale and the ground water aquifer does exist, what are the important factors influencing contaminant transport and what are the corresponding time frames? He described the fundamental equations and capabilities of the codes used for modeling fluid flow and contaminant transport (TOUGH+RealGasH2O and TOUGH+RealGasH2OCont) and for modeling coupled flow-thermal-geomechanical processes (coupling with the FLAC3D code and the ROCMECH code).

Dr. Moridis presented verification examples: 1) real gas flow and water flow in a cylindrical reservoir and 2) gas flow in a tight gas reservoir with a vertical well intersecting a vertical fracture plane. He also presented numerical simulation results from three application examples for horizontal wells in shale: 1) gas production from a shale gas reservoir, 2) gas production from a shale gas reservoir with a complex fracture system, and 3) flowing gas composition changes in shale gas wells.

Dr. Moridis expanded on topics presented during the April 17th workshop. He provided more detail on the mesh generation process for complex three-dimensional geometries. He also discussed conceptual model building and preliminary results for several scenarios (abandoned leaking wells and penetrating fractures). He noted that more than 400 different scenarios have been examined and that his presentation had highlighted only a few of these, to illustrate how the calculations were performed and to describe some preliminary results.

Key Discussion Themes

Participants were asked to consider the following questions:

- What pros and cons of the scenarios do the participants see?

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- What other, different scenarios would participants recommend EPA consider?
- What scenarios does industry typically model?
- Are there different models/approaches EPA should consider?
- How does industry conduct modeling to address subsurface scenarios?

Individual participants offered the following comments during the discussions:

Model complexity. Several participants stated that, while they understood the desire to investigate the physical possibility of the pathways, actual geologic conditions are much more complex—the shale layer alone can have hundreds or thousands of vertical layers. An EPA participant noted that while the TOUGH+ modeling system can represent different levels of conceptual complexity, EPA intends its study to capture the essence of the system appropriate for the purpose of impact screening. For example, the impact of thousands of horizontal layers can decrease the distance of vertical fracture migration, and can decrease the extent of vertical fluid migration due to leak-off from the well annulus into the overburden formations.

Description for the public. Several participants raised implications of simplification for public understanding, feeling that models need to reflect what is actually underground and how wells are constructed (i.e., cement and surface casing to provide multiple barriers). An EPA participant agreed that it would be useful to document model performance for those scenarios that reflect best practices with remote possibility of drinking water impact. A participant stated that there are pitfalls in presenting three-dimensional reality in two dimensions and recommended the use of a three-dimensional perspective.

Geomechanical likelihood of scenarios. Several participants raised the issue of the likelihood or plausibility of the geologic scenarios:

- Several participants asked why a scenario would be considered at all, if it is unrealistic from a geological perspective (e.g., a hydraulically induced fracture creating a pathway from reservoir to aquifer). It was stated that EPA is trying to consider the whole spectrum of possibilities; if it is determined that there is no plausible combination of variables to cause a particular situation, concerns about that situation will be allayed. A participant stated that the "fracture to surface" question comes up regularly in public discussion and needs to be answered.

- Several participants recommended that EPA consider the probability of occurrence for the specific scenarios considered. An EPA participant responded that the Agency does not have the knowledge of or access to the large number of data sets necessary for the derivation of probability estimates.

- Several participants discussed the importance of modeling realistic initial conditions and demonstrating that the model successfully represents the pre-hydraulically fractured condition where insignificant gas migration occurs.

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- It was suggested that EPA work with geologists regarding the permeability of natural faults.

- It was noted that experts consulted for scenario selection indicated that Scenario A (production well) was the most likely pathway, and Scenario E (offset well) the second most likely. It was also noted that a recently published study, based on the EPA/LBNL modeling, showed a remote possibility that the induced fault reactivation pathway will connect to shallow ground water aquifers given typical separation distances (Rutqvist et al., 2013, http://dx.doi.org/10.1016/j.petrol.2013.04.023).

- A participant raised the issue of proppant transport not being considered in the model (considering that vertical proppant transport in slickwater shale gas is limited given the transport physics and fracture conductivity of the upper portion of the "un-propped" fracture). It was stated that the model is not yet sophisticated enough to handle proppant transport; it currently represents the presence of proppants as fractures that do not close.

Calibration, verification and validation. Several participants noted the importance of validating the model and calibrating it against appropriate data. An EPA participant stated the importance of differentiating between verification (comparing model simulations to exact analytical solutions) and validation (determining whether a model is appropriate for its intended use). It was noted that LBNL has tested the models based on analytical solutions, laboratory studies and geomechanical field studies, but needs good controlled field data sets specific to hydraulic fracturing. Participants suggested several additional data sources, including the Department of Energy MWX datasets associated with the Field Fracturing Multi-Sites Project and the Westport microannulus Joint Industry Project study. A participant suggested a blind test: industry sends data, and EPA/LBNL conducts an analysis and sends it back to industry for comparison.

A participant asked whether industry has run models to prove or disprove the physics of the scenarios presented. It was stated that industry generally does not model scenarios it considers geomechanically unlikely or impossible; it models to mitigate risk for the local situation.

Need for additional industry data. EPA has extended the deadline for data submission to November 2013, and asked industry to provide data. (EPA/LBNL will send a detailed list of desired data to industry participants.) It was recommended that industry provide a brief description of geologic scenarios that do not make sense or have never been encountered.

Definition of protected water. Several participants noted that there are differences between state definitions of freshwater/drinking water and the federal definition of underground sources of drinking water (USDWs). This could be important, they stated: if the USDW definition is used, there might be a vertical separation of only a few hundred feet or less between the hydraulic fracturing level and the drinking water source, and this scenario is not reflected in EPA's study. It was suggested that EPA address the definition of protected water in its study.

Other scenarios. A participant asked whether tight sandstone formations and coalbed methane (CBM) were modeled, stating that CBM may be the highest-risk scenario (injecting directly into

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or very near to aquifers). An EPA participant said it has not been a priority scenario to date, given resource considerations, but could be considered in the future.

Industry participants were asked to send sketches of any scenarios that may have been overlooked or inadequately described so far.

Units of measurement. Several participants requested that study results be reported in common oilfield units (e.g., barrels per day, psi, standard cubic feet) in addition to the International System units required by peer review publications, to promote better understanding of the data by industry and the public.

Concluding remarks

In concluding the follow-up session, the co-chairs thanked the participants for bringing many different perspectives to help ensure that the drinking water study is scientifically sound. They reiterated that the models can be improved with more data, and stated that EPA will follow up with specific requests for needed data.

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Appendix A.

Extended Abstracts from Session 1:
Well Design and Construction to Protect Drinking Water

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Proposed Analyses from the Well File Review

Nathan Wiser

U.S. Environmental Protection Agency, Office of Research and Development

Information presented in this abstract is part of the EPA's ongoing study. EPA intends to use this, combined with other information, to inform its assessment of the potential impacts to drinking water resources from hydraulic fracturing. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

As part of its *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources,* the US Environmental Protection Agency (US EPA) is reviewing materials from nine oil and gas well operators about well construction, operation, and monitoring at oil and gas production wells. This abstract describes the information collection, its relationship to the overall study, and selected portions of the US EPA's proposed analysis.

Background

Natural gas plays a key role in our nation's clean energy future. The United States has vast reserves of natural gas that are commercially viable as a result of advances in horizontal drilling and hydraulic fracturing technologies, which enable greater access to oil and gas in rock formations deep underground. These advances have spurred a significant increase in the production of both natural gas and oil across the country.

Responsible development of America's oil and gas resources offers important economic, energy security, and environmental benefits. However, as the use of hydraulic fracturing has increased, so have concerns about its potential human health and environmental impacts, especially for drinking water. In response to public concern, the U.S. House of Representatives requested that the US EPA conduct scientific research to examine the relationship between hydraulic fracturing and drinking water resources (USHR, 2009).

In 2011, the US EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources.* The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, if any, and to identify the driving factors that may affect the severity and frequency of such impacts. Scientists are focusing primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil- and gas-producing formations.

The US EPA has designed the scope of the research around five stages of the hydraulic fracturing water cycle. Each stage of the cycle is associated with a primary research question:

- *Water acquisition:* What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?

- *Chemical mixing*: What are the possible impacts of hydraulic fracturing fluid surface spills on or near well pads on drinking water resources?

- *Well injection*: What are the possible impacts of the injection and fracturing process on drinking water resources?

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- *Flowback and produced water*: What are the possible impacts of flowback and produced water (collectively referred to as "hydraulic fracturing wastewater") surface spills on or near well pads on drinking water resources?

- *Wastewater treatment and waste disposal*: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources?

In December 2012, US EPA released its *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report* (US EPA, 2012a). The Well File Review project is one of the 18 research projects described in the *Progress Report*.

Relationship of Well File Review to the Study

The Well File Review provides an opportunity to assess well construction and hydraulic fracturing operations, as reported by companies that own and operate oil and gas production wells. While information from the will file review will help to address all of the primary research questions, US EPA's presentation at the Well Construction/Operation and Subsurface Modeling Workshop focuses on the well injection water cycle stage. Results from the review will inform answers to the following secondary research questions:

- How effective are current well construction practices at containing gases and fluids before, during, and after fracturing?

- Can subsurface migration of fluids and gases to drinking water resources occur and what local geologic or man-made features may allow this?

Project Introduction

The process of planning, designing, permitting, drilling, completing, and operating oil and gas wells involves many steps, all of which are ultimately controlled by the company that owns or operates the well, referred to as the "operator." Assisting the operator are service companies that provide specialty services, such as seismic surveys, lease acquisition, road and pad building, well drilling, logging, cementing, hydraulic fracturing, water and waste hauling, and disposal. Some operators can perform some of these services on their own and some rely exclusively on service companies.

During the development and production of oil and gas wells, operators receive documentation from service companies about site preparation and characteristics, well design and construction, hydraulic fracturing, oil and gas production, and waste management. Operators typically maintain much of this information in an organized file that cumulatively represents the history of the well. The US EPA refers to this file as a "well file."

For this project, the US EPA is reviewing well files from hydraulic fracturing operations in different geographic areas that are operated by companies of various sizes. These wells include vertical, horizontal, and deviated wells that produce oil, gas, or both from differing geological environments. This review is to provide information that can be used to identify practices that may impact drinking water resources.

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Research Approach

While a portion of the data needed for this project is reported to state oil and gas agencies, the most complete dataset is available only in the well files compiled by oil and gas operators.[1] Further, different states have different reporting requirements. This section describes the process used by the US EPA to select well files for review, the information requested, and the planned analyses.

Well File Selection. The US EPA used a list of hydraulically fractured oil and gas wells provided to the agency by nine hydraulic fracturing service companies (referred to hereafter as the "service company well list") to select 350 specific well identifiers associated with nine oil and gas operators.[2] The service company well list contains close to 25,000 well identifiers associated with wells that were reported by the service companies to have been hydraulically fractured between September 2009 and October 2010 and identifies approximately 1,200 oil and gas operators related to those wells.

Counties containing the well identifiers were grouped into four geographic regions—East, South, West, and Other[3]—according to a May 9, 2011, map of current and prospective shale gas plays within the lower 48 states (US EIA, 2011c). This grouping process allowed the US EPA to select wells that reflect the geographic distribution of hydraulically fractured oil and gas wells.

US EPA used a stratified random process to select nine well operators ranging in size (based on the number of wells hydraulically fractured during the 2009-2010 time period) and geographic location.[4] The nine operators were associated with about 2,500 well identifiers. The US EPA initially chose 400 well identifiers to request the associated well files for its analysis. The selection of 400 well identifiers required balancing goals of maximizing the geographic diversity of wells and maximizing the precision of any forthcoming statistical estimates. The well identifiers were chosen using an optimization algorithm that evaluated the statistical precision given different allocations across operating company/shale play combinations.

Due to resource and time constraints, the US EPA subsequently decided to review 350 well files, so 50 of the 400 selected well identifiers were randomly removed. This sample size is large enough to be considered reasonably representative of the total number of wells hydraulically fractured by the nine service companies in the United States during the specified time period.

Data Requested. An information request letter was sent in August 2011 to the nine operators, asking for 24 distinct items organized into five topic areas: (1) geologic maps and cross sections; (2) drilling and completion information; (3) water quality, volume, and disposition; (4) hydraulic

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[1] The EPA analyzed several state oil and gas agency websites and estimated that it would find less than 15% of the necessary data from websites to answer the research questions.

[2] The EPA used the service company well list because it is unaware of the existence of a single list showing all oil and gas production wells in the United States, their operators, and whether each well has been hydraulically fractured.

[3] If any portion of a county was within one of the shale gas plays defined on the map, the entire county was assigned to that shale play and the corresponding geographic region. Counties outside the shale gas plays were grouped in to the "Other" region, which includes areas where oil and gas is produced from a variety of rock formations. See the Progress Report for a more detailed discussion (USEPA 2012).

[4] The well selection process is described in detail in the Progress Report (USEPA 2012).

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fracturing; and (5) environmental releases.[5] Table 1 shows the potential relationship between the five topic areas and the stages of the hydraulic fracturing water cycle.

Table 1. The potential relationship between the topic areas in the information request and the stages of the hydraulic fracturing water cycle.

Water Cycle Stage	Information Request Topic Areas				
	Geologic Maps and Cross-Sections	**Drilling and Completion Information**	**Water Quality, Volume, and Disposition**	**Hydraulic Fracturing**	**Environmental Releases**
Water acquisition			✓	✓	
Chemical mixing		✓	✓	✓	✓
Well injection	✓	✓	✓	✓	✓
Flowback and produced water			✓	✓	✓
Wastewater treatment and waste disposal			✓	✓	

Well File Review and Analysis. The US EPA received responses to the August 2011 information request from each of the nine operators. Data and information contained in the well files is being extracted from individual well files and compiled in a single Microsoft Access database. All data in the database are linked by the well's API number; this process is described in more detail in the quality assurance project plan for this research project (US EPA, 2012b).

Status and Preliminary Data

Of the 350 well identifiers selected for analysis, the US EPA received information on 334 unique wells.[6] The well locations are distributed within 13 states: Arkansas, Colorado, Kentucky, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wyoming. Figure 1 shows a map of the well locations.

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[5] See the text of the information request for the specific items requested under each topic area. The information request can be found at http://www.epa.gov/hfstudy/August_2011_request_letter.pdf.

[6] Sixteen of the 350 well identification numbers were not valid for this project: 13 were duplicate entries, one was in Canada, one was not a well, and one was not actually owned by the selected operator. In total, roughly 5% of the 350 well identifiers chosen for review by the EPA do not correspond to oil and gas wells that have been hydraulically fractured. This provides a rough assessment of the accuracy of the original data received from the nine hydraulic fracturing service companies (the service company well list).

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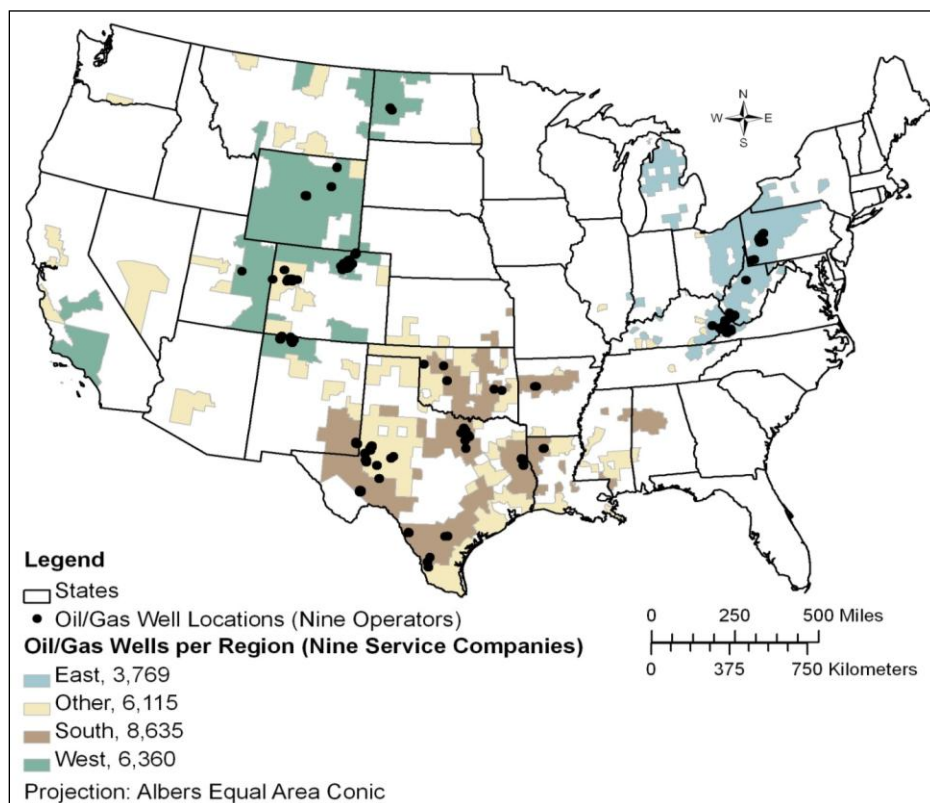
Figure 1. Locations of wells (black points) selected for the Well File Review. The information request to service companies (September 2010) resulted in county-scale locations for about 25,000 wells. The service company wells are represented above as regional well summaries. (ESRI, 2010a, b; US EPA, 2011a, b)

The US EPA received approximately 9,670 electronic files in response to the August 2011 information request. The amount of information received varied from one well file to another. Some well files included nearly all of the information requested, while others were missing information on entire topical areas. Some of the data received were claimed as confidential business information (CBI) under the Toxic Substances Control Act (TSCA). The US EPA has contacted all nine of the oil and gas operators to clarify its understanding of the data, where necessary, and to discuss how to depict the well file data while still protecting confidential information. The analyses described in this abstract are being performed according to CBI procedures (US EPA, 2003), and the results are considered CBI until determinations are made or until data masking has been done to prevent release of CBI information.

The US EPA is extracting available data from the well files that can be used to answer research questions related to all stages of the hydraulic fracturing water cycle. As of April 2013, the US EPA had extracted, and continues to extract, the following available information from all of the well files:

- Open-hole log analysis of lithology, hydrocarbon shows, and water salinity
- Chemical analyses of various water samples

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- Well construction data

- Cement reports

- Cased-hole logs, including identifying cement tops and bond quality

Other data to be extracted includes the following:

- Source of water used for hydraulic fracturing

- Well integrity pressure testing

- Fluid volumes injected during well stimulation and type and amount of additives and proppant used

- Pressures used during hydraulic fracturing

- Fracture growth data including that predicted and that observed

- Flowback and produced water data following hydraulic fracturing including volume, disposition, and duration

- Spills reported

The US EPA is creating queries on the extracted data that are expected to determine whether drinking water resources were protected from hydraulic fracturing operations. The results of these queries may indicate the frequency and variety of construction and fracturing techniques that could lead to impacts on drinking water resources. The results may provide, but may not be limited to, information on the following:

- Sources of water used for hydraulic fracturing

- Vertical distance between hydraulically fractured zones and the top of cement sheaths

- Quality of cementing near hydraulic fracturing zones, as determined by a cement bond index

- Number of well casing intervals left uncemented and whether there are aquifers in those intervals

- Distribution of depths of hydraulically fractured zones from the surface

- Frequency with which various tests are conducted, including casing shoe pressure tests and casing pressure tests

- Types of rock formations hydraulically fractured

- Types of well completions (e.g., vertical, horizontal)

- Types and amounts of proppants and chemicals used during hydraulic fracturing

- Amounts of fracture growth

- Distances between wells hydraulically fractured and geologic faults

- Proportions of reported fluid flowed back to the surface following hydraulic fracturing and the disposition of the flowback

- Spill incidents and remedial steps taken

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- Frequency of annular pressure monitoring during hydraulic fracturing

- Frequency of verification of cement sheath location and bond quality

- Frequency of water quality monitoring to define drinking water resources and to determine before and after water quality conditions

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Geophysical Logging for Characterization of Fresh- and Saline- Water Flow Zones in the Fractured Bedrock of the Northern Appalachian Basin
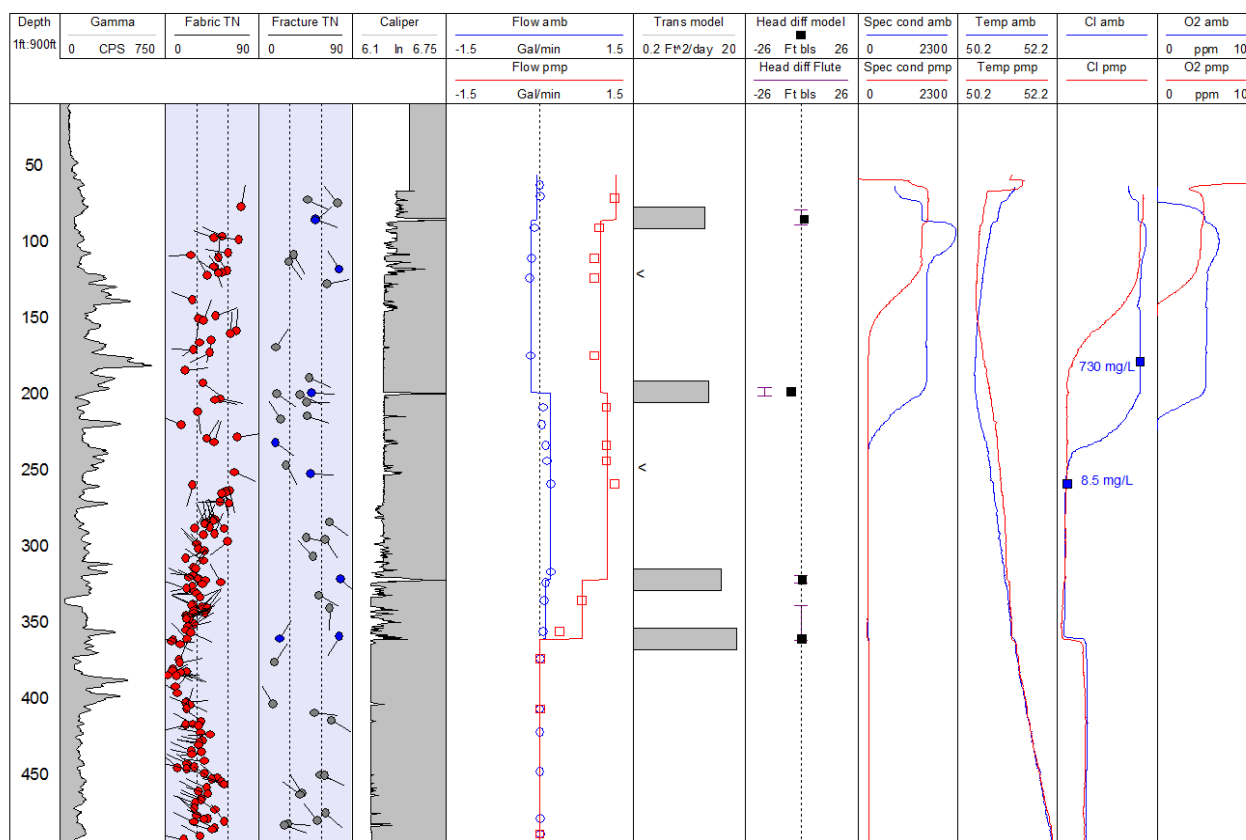
John H. Williams and Dennis W. Risser
U.S. Geological Survey

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The claims made by participants have not been verified or endorsed by EPA.

To protect drinking water aquifers during shale gas-play development in the northern Appalachian Basin, fresh- and saline-water flow zones in the fractured bedrock need to be isolated by properly designed and installed well casing and cementing programs. Historically, characterization of the fresh- and saline-water flow zones has relied on spotty information reported during drilling (Williams, 2010). Geophysical logs were not collected before the installation of surface casing, and other than gamma, and sometimes density and (or) neutron, were not collected up to land surface. Although useful for lithologic identification, including delineation of carbonaceous zones that are potential sources of thermogenic methane, the nuclear logs that have been traditionally collected do not provide the information needed to characterize fresh- and saline-water flow zones in the fractured bedrock.

At present, several gas-development companies operating in the Marcellus fairway of north-central Pennsylvania routinely collect a suite of geophysical logs from the surface and intermediate cased intervals of the first topset hole at each multi-well pad prior to the installation of casing and cement. The suite of geophysical logs, which includes gamma, induction resistivity, density, and neutron, is interpreted to estimate bulk water resistivity of the bedrock. Complicated by lithologic effects and the very low porosity and discrete fractured nature of the bedrock, this petrophysical approach reportedly has provided estimates of the deepest fresh groundwater that are consistent with the depths of surrounding domestic water-supply wells at some sites but not at other sites.

Over the past 25 years, the U.S. Geological Survey (USGS) has applied and refined an integrated geophysical logging approach at fractured-bedrock research and groundwater contamination sites throughout the Northeast (Paillet, 1985; Williams and Conger, 1990; Johnson; 1996; Williams and Paillet; 2002; Williams and Johnson, 2004; and Williams, 2008). The approach includes caliper, nuclear, and resistivity logging; wellbore imaging using optical and acoustic televiewers and video cameras; fluid-property logging using temperature, fluid resistivity, specific-conductance, and multi-parameter water-quality tools and downhole water samplers; and flowmetering using heat-pulse and electromagnetic flowmeters. Analysis of this logging suite has provided information on the distribution and orientation of fractures and their relation to bedrock fabric and lithology as well as the transmissivity and hydraulic head of the flow zones and their water quality (fig.1).

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Figure 1. Integrated geophysical log analysis for bedrock fabric, fractures, and hydraulic properties and water quality of flow zones at a discrete-zone monitoring well site in southern Dutchess County, New York. Depth in feet below land surface.
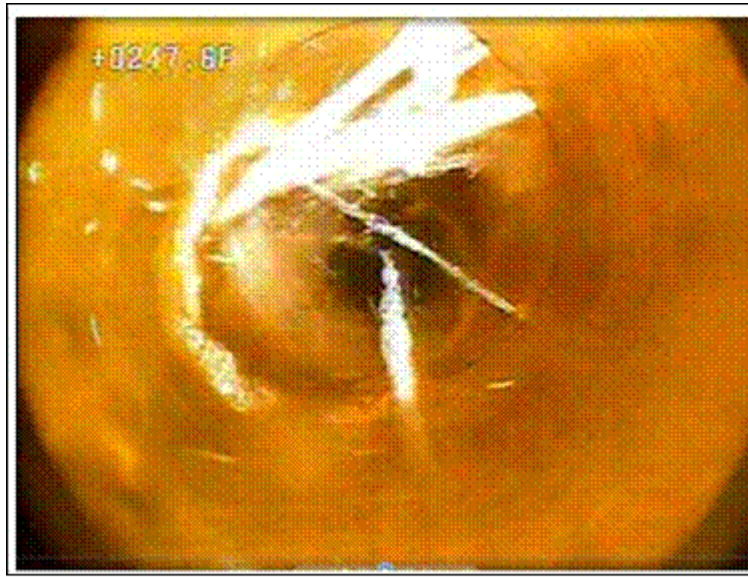
In cooperation with the Pennsylvania Geological Survey (PaGS), the USGS applied the integrated geophysical logging approach at a deep corehole site in a high-relief upland setting in western Bradford County, Pennsylvania. The Gleason corehole, which was 1,664 feet deep, penetrated sandstone, siltstone, and claystone of upper Devonian, Mississippian, and Pennsylvanian age. Lithologic and fracture analysis from the optical- and acoustic-televiewer, video, and nuclear logs complimented and enhanced that provided by detailed examination of the core by PaGS geologists. Lower gamma counts were associated with sandstones and higher counts with siltstone and claystone intervals. The highest gamma counts were associated with carbonaceous beds. More than 60 percent of the fractures, which included bedding-related and steeply dipping fractures, were penetrated above 300 feet below land surface. Few fractures were penetrated below 800 feet below land surface.

The lithologic and fracture analysis combined with the interpretation of the fluid- property, flowmeter, and video logs characterized the flow zones penetrated by the Gleason corehole (figs. 2-6). Multiple bedding-parallel and steeply dipping fractures between 50 to 294 feet below land surface were zones of fresh-water inflow including cascading water from those zones above the composite water level at 270 feet below land surface. Downhole samples of the fresh water had total dissolved-solids content of less than 100 mg/L. Bedding-parallel fractures at 553, 661, and 712 feet below land surface were zones of lower hydraulic head and fresh-water outflow. The

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temperature log displayed sharp breaks in slope at the 661- and 712-foot zones reflecting the change in flow at these depths. Below the 712-foot zone, the temperature log approached the geothermal gradient, which indicated a marked decrease in fracture transmissivity below that depth. Bedding-parallel fractures at 915 and 1,026 feet below land surface were zones of saline-water inflow. A fracture in a carbonaceous bed at 1310 feet below land surface may also have been a zone of saline-water inflow. The repeated specific conductance logs reflected the inflow of saline water and its movement downward due to the density contrast with the freshwater used to flush the corehole, and upward to the lowerhydraulic-head zone at 712 feet below land surface. Downhole samples of the saline water had a total dissolved-solids content of more than 10,000 mg/L and a dissolved concentration of thermogenic methane that was super-saturated under atmospheric conditions.
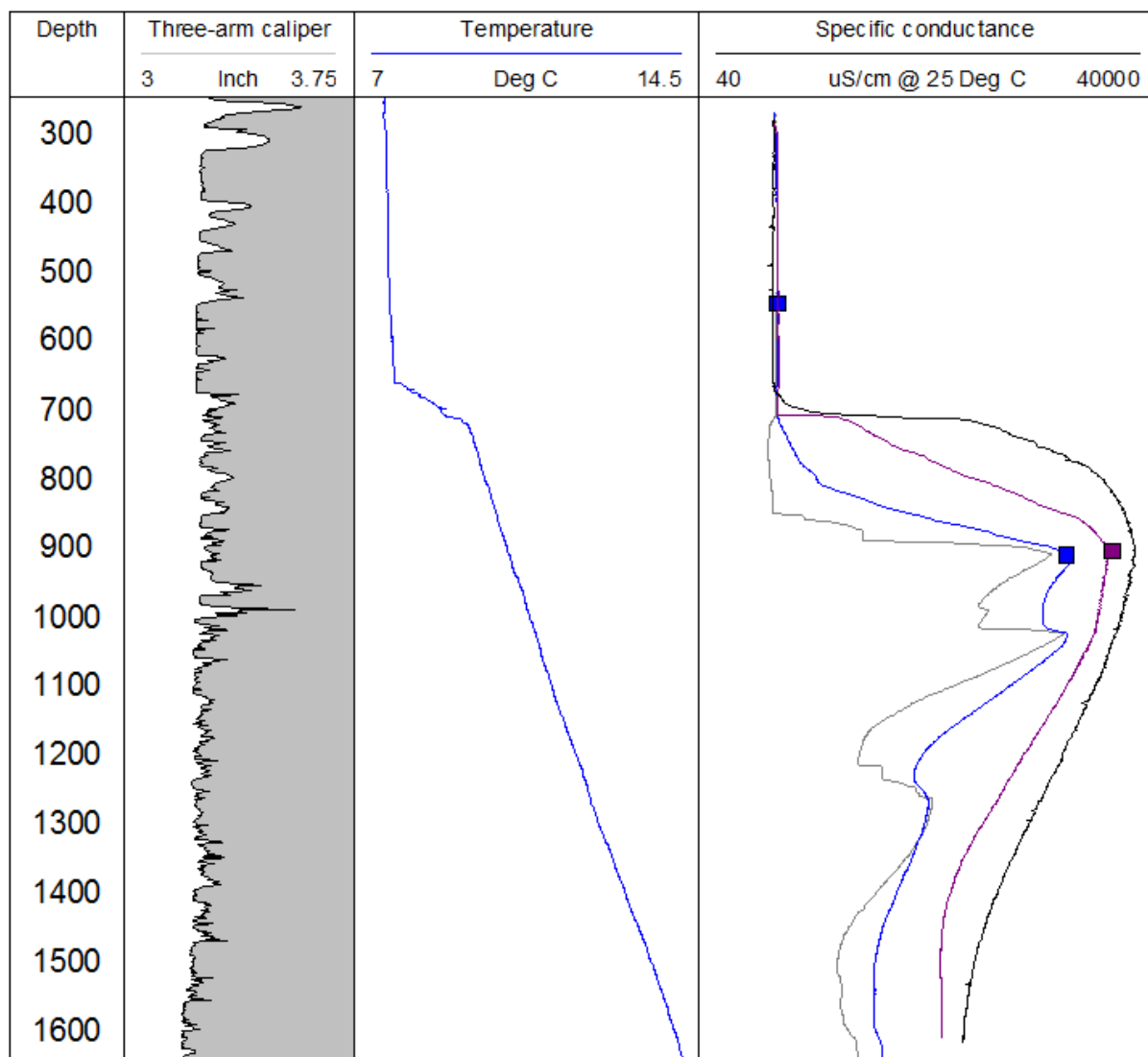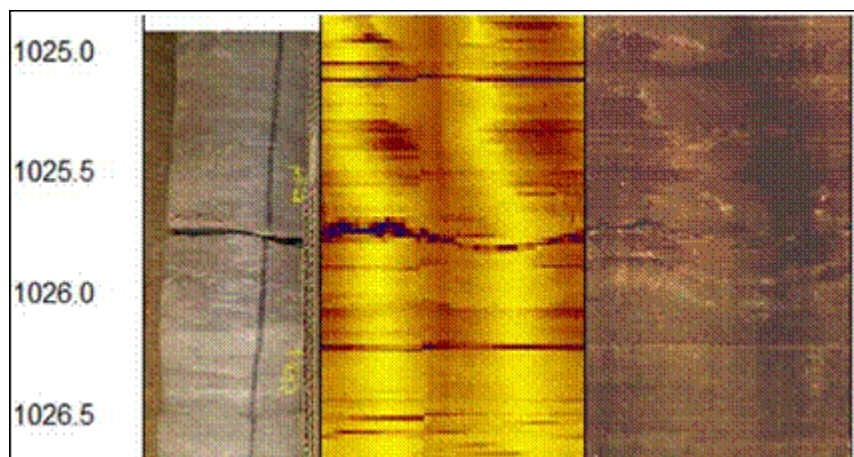

Figure 2. Caliper, temperature, and specific conductance logs of the Gleason corehole, western Bradford County, Pennsylvania. Depth in feet below land surface.

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Figure 3. Video still image of fresh-water inflow from a bedding-parallel fracture penetrated at 248 feet below land surface by the Gleason corehole, western Bradford County, Pennsylvania.
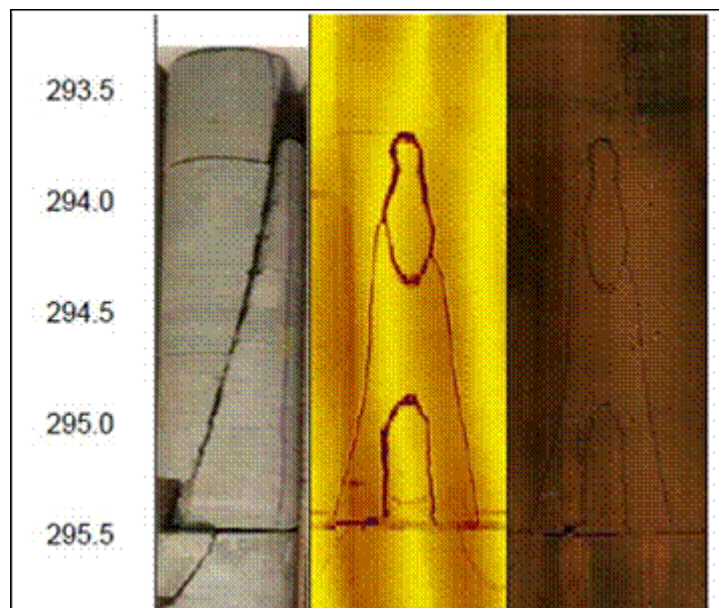
Figure 4. Core photograph and acoustic and optical televiewer images of bedding-parallel and steeply dipping fractures associated with a fresh-water inflow zone penetrated at 294 feet below land surface by the Gleason corehole, western Bradford County, Pennsylvania.

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Figure 5. Core photograph and acoustic and optical televiewer images of a bedding-parallel fracture associated with a saline-water inflow zone penetrated at 1,026 feet below land surface by the Gleason corehole, western Bradford County, Pennsylvania.

Figure 6. Video still image of saline-water inflow from a bedding-parallel fracture penetrated at 1,026 feet below land surface by the Gleason corehole, western Bradford County, Pennsylvania

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The results from the geophysical logging of the deep corehole suggest that the integrated approach would provide an efficient means for geohydrologic and water-quality characterization of bedrock in the northern Appalachian Basin including the delineation of lithology, fractures, and fresh- and saline-water flow zones. The characterization of fractured bedrock penetrated by topset holes at multi-well pads would benefit from the collection of fluid-property and video logs in addition to the petrophysical logging suite. Inclusion of a multi-arm caliper log would provide enhanced fracture delineation as compared to that provided by the single-arm caliper log typically collected with the petrophysical logs. Application of the complete integrated geophysical logging approach including televiewer imaging and fluid-property logging and flowmetering under ambient and pumped conditions would be beneficial for the design and installation of discrete-zone monitoring wells at multi-well pads, and the investigation of domestic water-supply wells that potentially have been impacted by shale-gas development.

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An Overview of Well Construction and Well Integrity
Related to Hydraulically Fractured Wells

Talib Syed
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Abstract

Hydraulic fracturing (HF) to produce hydrocarbons has a long history in the U.S. (first introduced in the Hugoton gas field, Kansas in 1947) and elsewhere. The use of hydraulic fracturing is expected to increase, particularly from unconventional tight oil/gas reservoirs, as the technology improves and conventional hydrocarbon deposits are depleted. However, concerns have been raised in several quarters on the risks associated with HF operations and the potential impacts on drinking water resources from HF operations. Therefore, sound well design/construction and well integrity, operation, and monitoring are critical in ensuring that wells drilled and completed for HF purposes do not place the public, workers, and the environment at risk.

This presentation presents design considerations for (1) the construction of wells that are utilized for HF purposes including casing design, (2) cement design and cementing/zonal isolation, and (3) monitoring methods to verify that the wells maintain mechanical integrity throughout their life cycle (including at pre-, during and post-frac operations). The importance of isolating potential flow zones in uphole sections of the well (zonal isolation) when designing cement slurries ("gas-tight") and implementing a cement job (including top of cement – TOC selection) is also discussed in the presentation. The presentation also includes recommendations from a regulatory perspective for managing the risks associated with HF operations to: (1) prevent the loss of integrity at a subject well, (2) reduce the risks of inter-wellbore communication between a HF well and an offset well, (3) maintain well control at an offset well in the event of inter-wellbore communication with a HF well, and (4) prevent impacts to overlying USDWs and/or to surface. The recommendations for well integrity include engineering best practices (including minimum number of barriers) based on NORSOK D-010 and API standards.

Hydraulic Fracturing

Hydraulic fracturing is the process of transmitting pressure by fluid or gas to create cracks or to open existing cracks in hydrocarbon bearing rocks. In general, HF treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well.

Fractures in oil and gas reservoirs will extend along the "path of least resistance". At any point in the zone of interest, the rock will have three stresses acting upon it: a vertical stress primarily due to the weight of the rock that lies from the surface to the depth of the target zone, and two horizontal stresses that may be thought of as front to back and side to side (see Figure 1). The fracture is created by using fluid pressure to "push back" against the least of these three stresses thus opening the fracture.

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At the depths of typical oil and gas tight/shale formations, the lowest stress will be one of the horizontal stresses as the weight of the rock above exceeds any of the forces squeezing from the sides. Pushing against the lowest horizontal stress results in a vertical fracture, much like pushing horizontally against a jammed door creates a vertical opening. Once a fracture is initiated, it will extend, provided that additional fluid is pumped to maintain the pressure within the fracture.
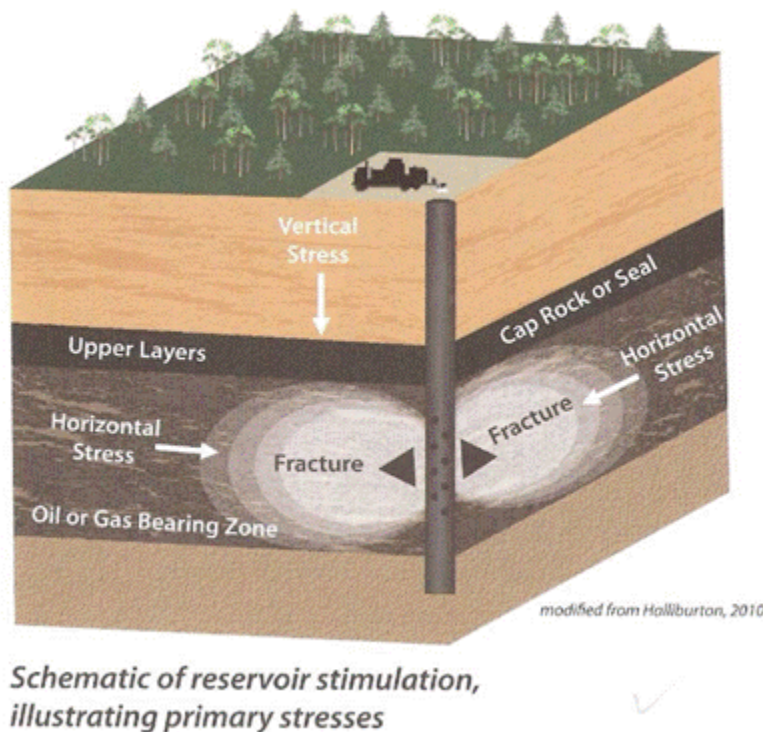
Figure 1 (courtesy, CSUR) Vertical or horizontal fractures and how far will the fracture extend

Slightly more pressure is required to break down a formation than to propagate a fracture. The average fracture gradient (FG) in reservoirs deeper than 6000 feet (1800 m) is approximately 0.69 psi/ft. The overburden stress is normally between 0.99 to 1.08 psi/ft and if the FG is less than this, a vertical fracture will form. In shallow reservoirs (at depths less than 2000 feet – 600 m), FGs can be higher than 1.08 psi/ft and here horizontal fractures can form (Schechter, 1992).

In the vertical direction, the fractures will extend until they reach a more ductile material. Ductile materials such as softer shales are more difficult to fracture than brittle shale rocks. These ductile layers provide the containment and cause the fracture to travel horizontally within the more brittle layer(s).

The fracture will extend laterally as long as the fluid pressure within the fracture exceeds the lowest stress pressure. Several factors contain the unlimited growth of a fracture in a lateral plane:

- The fracture fluid tends to "disperse" into the rock formation;
- The fracture fluid may encounter pre-existing natural fractures and follow them;

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- As the fracture extends, sometimes as much as several hundreds of feet, the fracture pressure of the fluid required increases beyond the capability of the pumping equipment.

Where fracturing of oil- and gas-bearing sandstones (interspersed with shales) takes place, if the shale layers act as barrier layers, the hydraulic fracture can be contained within the pay zone (thereby avoiding penetration into overlying/underlying sandstone aquifers). The contrast in *horizontal in-situ stresses* and the *stiffness* (a material property also known as *critical stress intensity factor, fracture toughness, or fracturability*) - as characterized by the shear modulus of the zones, play significant roles in the containment of the hydraulic fracture (Simonson et al, 1990):

- Hydraulic fractures in a pay zone located between two adjacent barrier layers tend to be contained, provided the stiffness of the pay zone is less than the stiffness of the barrier layers. If the opposite condition exists, barrier penetration is likely.

- Migration of a hydraulic fracture, either upward or downward in an isotropic, homogeneous medium may be controlled by the density of the hydraulic fracturing fluid. If the fluid density gradient is greater (less) than the minimum horizontal in-situ stress gradient, then downward (upward) migration is probable.

- When the in-situ stress in the bounding layers is greater than in the pay zone, then those layers serve as a barrier to vertical extension of the fracture (it may be possible to detect fracture propagation into the barrier by an increase in pumping pressure). The most reliable method to determine in-situ stresses is based on minifrac field tests with the ISIPs (instantaneous shut-in pressures) measured for specific isolated zones (Schechter, 1992).

Well Construction

A key element of successful HF is proper well construction (includes both drilling and completion). Proper casing and cement design are critical elements in ensuring sound well integrity throughout its life-cycle.

Casing Design

As is required in all engineering designs, surface equipment and down-hole tubulars are designed for the anticipated operating pressures/loads (including treatment pressures during hydraulic fracturing stimulation operations).

The casing is exposed to different loading conditions during various well operations (landing, cementing, drilling, production, stimulation/hydraulic fracturing etc.). It has to be designed to withstand tensile, burst, and collapse loads. Since it is impossible to predict the magnitude of these loads during the life of the casing, the design is based on a worst-case scenario. Since the casing rating also deteriorates with time (wear and tear), safety factors are used to make sure that the casing could withstand expected loading conditions.

Collapse pressure is mainly due to the fluid pressure outside the casing (due to drilling fluid or cement slurry). Overpressure zones could also subject the casing to high collapse pressure. The casing's critical collapse strength is a function of its length, diameter, wall thickness, Poisson's Ratio etc. Burst loading on the other hand is due to the fluid pressure inside the casing. Severe

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burst pressure occurs if there is a kick during drilling operations. The tensile strength on the other hand originates from pipe weight, bending load and shock load. The axial force due to pipe weight is its weight in air less the buoyancy force. Bending force results when the casing is run in deviated/horizontal wells where the upper portion of the casing is in tension whereas the lower portion is in compression. Shock load on the other hand is generated by setting of the slips and application of hoisting brakes. The sudden stoppage when casing is run generates stress waves along the casing string.

In addition to the three loading conditions described above, casing design should also consider the likelihood of buckling, piston and thermal effects. Buckling results when the casing is unstable (e.g. partially cemented – higher probability in deviated/horizontal sections). The casing string will exhibit a helical configuration below the neutral point, resulting in rapid wear at the neutral point and eventually lead to casing failure. Piston force is due to the hydrostatic pressure acting on the internal and external shoulders of the casing string while thermal effects refer to the expansion or shortening of the casing due to increase or decrease in temperature (SINTEF, 2007).

The following recommendations are being made for well construction and casing design considerations for wells that will be utilized for stimulation/hydraulic fracturing purposes:

- Horizontal wells are drilled basically in three ways: rotating and sliding the drill string with a top-drive or Kelly rig; coiled tubing (CT) drilling; or rotary-steerable systems (RSSs). Rotating and sliding is the most common method used in lateral wells – problems with this method include: increased time, uneven bit wear, increased reaming time, and sticking of casing/completion string. If a directional or CT system is used in conjunction with an RSS, it delivers a smooth "gunbarrel" borehole.

- Horizontal wells used for production from unconventional reservoirs may need to be drilled as quickly as possible (underbalanced or overbalanced) to minimize formation damage. During underbalanced drilling, wellbore instability in the reservoir and any overburden formations exposed to the low well pressures may be a significant concern.

- Inability to maintain a borehole within the pay zone or borehole undulation may lead to reducing the number of fractures along the lateral, difficulty in initiating a hydraulic fracture (may require stronger casing allowing higher treating pressures for fracture initiation), and water being trapped in the low spots of the lateral resulting in choking back gas production. Logging while drilling (LWD) and a reservoir model can aid in landing and maintaining the borehole within the target zone and in log correlation. Image logs can be used to determine if any drilling-induced fractures exist along the borehole and their associated azimuth. With this information, fracture staging can be designed to avoid travelling down a fault or an old hydraulic fracture (Baihly et al, 2009).

- A critical part of drilling a well in an unconventional reservoir is to drill a gauge hole which allows for easier placement of casing and/or completion strings in the lateral and leads to higher success rates for packer and cement systems to isolate between stimulation stages (Baihly et al, 2009). If the borehole is washed out, log readings will be affected and obtaining a primary cement seal is difficult. This in turn affects zonal

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isolation and may require a cement squeeze job prior to running tests or pumping stimulation treatments.

- In most cases, a well in an unconventional reservoir is uneconomic to produce unless the optimum fracture treatment is designed and pumped into the formation. Therefore, the entire well prognosis - hole sizes, casing sizes, tubing sizes, wellhead, flow lines, and perforation scheme should be designed to accommodate the fracture treatment. Tubular concerns revolve around the dilemma of requiring large tubulars to pump the fracture treatment at higher injection rates versus the need for small tubulars to minimize liquid loading in gas wells. Therefore, good coordination between the completion engineer and drilling engineer is critical prior to spudding the well, so that the drilling bit and casing programs meet the needs of the completion engineer (Holditch, 2007).

- The surface casing must be set to at least 200' – 300' below the base of USDW (setting depth will vary depending upon regulatory requirements) and cemented back to surface. If cement returns are not obtained at the surface, or the cement level in the annulus drops below the next casing string, a CBL log will need to be run, and appropriate remedial actions taken consistent with good engineering practice and regulatory requirements. A Top Job may also be considered as an option.

Cementing the Casing/Liner

The quality of the cementing operation is also critical in maintaining wellbore integrity. Besides selection of the proper cement systems, the placement of cement and the quality of the cement job are critical elements in assuring the well's integrity. It is very important to thoroughly circulate and cleanout the well prior to cementing in order to prevent mud mixed into the cement causing cavities or channels, resulting in potential cement degradation and/or creation of leakage pathways for either the treatment fluids or production fluids. Accurate knowledge of pore pressure/ fracture gradient profiles and cementing temperatures (both static and circulating) are essential to the success of the cement job.

Well deviation can also affect the quality and presence of the cement. The mill varnish is removed from the surface of the casing to ensure that the cement will bond to the steel surface. Centralizers are used to ensure that the casing is placed in the center of the borehole. After the cement slurry is pumped down-hole, a lighter drilling mud follows resulting in the casing being under compression from a higher differential pressure on the outside of the casing. Thus when the cement sets and drilling continues, the casing will always have an elastic load on the cement-casing interface, which is essential for maintenance of the casing-cement bond and to prevent channeling or micro-annulus effects in the cemented annulus.

The job procedure for cementing liners is similar to cementing casing. The cement is preceded with a weighted spacer to aid mud displacement and hole cleaning. Pump rates typically average in the 3 to 5 bbl/min range and the calculated cement slurry volumes are circulated to the liner top plus another 200 feet above. After the cement is displaced and the liner wiper plug landed, the liner hanger packer is set and tested and excess cement is circulated out. The liner is successfully cemented if no unusual events occurred during the job and if cement was circulated off the liner top after the liner hanger packer was set. Finally, cement bond logs (CBLs) may be

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run to evaluate the quality of the cement job, but in many instances operators might choose not to run these logs due to risk/ difficulty in accessing the lateral sections and additional time.

Zonal Coverage and Top of Cement Determination

Generally, regulations for production and injection wells (including wells that are hydraulically fractured) require that the surface casing be cemented all the way back to the surface. In some instances the intermediate casing may also be cemented back to the surface or into the next casing string annulus, creating a continuous cement barrier from surface to the top of the target zone. However, due to concerns from unintended fracturing of weak formations, this requirement for the intermediate/long string casings may not be imposed in all cases.

Well construction and local regulations determine the extent of cement coverage and cement performance requirements for each well section. It is important to evaluate which zones have potential to flow when designing the cement job to achieve suitable zonal isolation. Such zones should be covered to prevent flow after cementing, and the cement placement mechanics should be designed to maximize drilling fluid removal. Zones left un-cemented may not flow in the short term if pore pressure is balanced by drilling fluid hydrostatic pressure. However, barite sag and drilling fluid dehydration may lead to sustained casing pressure (SCP).

Cement top selection is influenced by the location of the potential flow zones, regulatory requirements and pore pressure/fracture gradient consideration. Higher density tail slurries may be more easily designed to be "gas tight" (gas controlling) than some lower density lead cements. Texas Railroad Commission (TRRC) standards require that all hydrocarbon zones be isolated with casing and cement with the TOC at least 500 feet above the top of the highest hydrocarbon zone. Some operators have chosen to bring the TOC to a higher depth to provide zonal isolation.

Problems in cementing horizontal wells

The major problems associated with obtaining a good cement job in horizontal wells (with a cemented casing/liner) can be categorized into four areas: hole cleaning and drilling-fluid displacement; centralization of pipe; optimizing cement slurry designs; and evaluation with acoustic logging tools. To address these problems and obtain a good cement job the following practices should be incorporated (Sabins,1990):

- A low-side solids channel may form by deposition and settling of drilled solids and drilling-fluid weighting material. Solids channels may not seal the annulus for the life of the well and also not confine the treatment fluids. These channels should be prevented from forming; however, if formed, they can be removed with thin flushes, maximum pump rates, hole-cleaning attachments, and pipe movement.

- Drilling fluid properties must be controlled within specific ranges – yield point, plastic viscosity, fluid loss, gel strength, and dynamic settling characteristics.

- Any casing eccentricity becomes critical in horizontal wells because of its effect on flow velocity distributions in the wellbore. Tops of cement on different sides of the annulus can be separated by hundreds of feet as a result of these effects.

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- Flow rate should be controlled at the higher displacement rate possible, so that breakdown of the critical horizontal portion of the wellbore does not occur during the cementing process.

- Spacer composition and type must be chosen carefully, with minimal settling at high deviation angles.

- Pipe movement, either reciprocation or rotation is beneficial and when used with wall cleaners is helpful in removing low-side solids in horizontal sections.

- Higher well-deviation angles generally make drilling-fluid removal more difficult. This requires greater attention to ensure that mechanical cementing aids function properly. The correct number of centralizers to be used (spacing) and the need to minimize drag is important. Casing sag generally determines the spacing between centralizers in a horizontal well.

- The use of wall cleaners (to remove filter cake and gelled drilling fluid) to allow better bonding of the cement between the formation face and the casing is somewhat controversial in horizontal holes. Poor pipe centralization and improper installation may lead to a bad cement job.

- Cement slurry properties take on added importance for use in horizontal wells. If free water is present in a cement slurry used in a horizontal well, a water channel can form through the cemented interval, allowing communication of fracturing or reservoir fluids.

- Standard cementing systems used in vertical and deviated wells can be used in horizontal applications, provided they are designed appropriately for horizontal wells.

- One of the primary concerns in multi-stage fracturing using plug and perf systems (with limited entry fracturing – LEF) in a horizontal well completed with a cemented casing/liner is adequate isolation between each perforation cluster/set. Openhole external packers, gel plugs or chemical packers, cements and openhole pre-perforated liner completions have all been used with varying degrees of success to control fracture placement at specific intervals along the lateral. Because conventional cements have a low solubility in acid, perforations can be difficult to break down, can inhibit fracture initiation and result in excessive near –wellbore friction (NWF) during stimulation and production. Acid-soluble cements (ASC) have gained wide acceptance for isolation between perforation sets without impeding stimulation and production. The dissolved pocket around the casing at the clustered perforation point eliminates tortuosity, fracture-entry pressure and skin effects as compared to conventional cements.

- After the cement is placed in a horizontal well and sufficient waiting-on-cement (WOC) time has elapsed, the quality of the cement job should be determined. Parameters include bonding to the pipe, annular fill, and presence of channels. In horizontal wells, one of the biggest problems is centralization of the acoustic tools to obtain accurate data. Good interpretation with acoustic bond tools and pulse-echo type tools is difficult because of decentralization of both the casing and the tool inside the casing.

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Cement Evaluation

Formation integrity and cement placement and strength are important parameters to be evaluated before drilling the next hole section. When the leak-off test (LOT) or the formation integrity test (FIT) results are inadequate, the operator can perform a cement squeeze to enhance the formation's pressure containment integrity or to seal a leaking cement sheath in the annulus. A repeat LOT or FIT may then confirm the squeeze results in confirming zonal isolation. Field evidence of a properly executed job may include records of spacer density and rheology, slurry density control, pump rates, pump pressures and observed returns which conform to the cementing plan. Based on job objectives, multiple techniques are available: temperature, noise, acoustic and ultrasonic cement logs.

Acoustic cement logs are run to determine cement tops as well as the quality of the casing-cement and cement-formation bonds. Acoustic impedance, Z, is defined as the product of the density (kg/m3) and acoustic velocity (m/sec) of a medium and is expressed in MRayl (10^6 kg/m^2 sec). Two classes of sonic logging tools exist: (1) sonic (cement bond log/variable density log – CBL/VDL) or segmented bond tool (SBT) and (2) ultrasonic (ultrasonic imaging tool – USIT) and the circumferential acoustic scanning tools (CAST-V and M) (Syed et al, 2010). Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier, since their interpretation can be highly subjective (API RP 65-2).

Factors that affect Cement Log Quality

There are many factors that affect the response of sonic logging tools. These factors include: micro-annulus, logging tool centralization, fast formation arrivals, use of lightweight cements and cement setting time (Boyd et al, 2006).

Micro-annulus. A micro-annulus is defined as a very small (approximately 0.01 to 0.1 mm) annular gap between the casing and the cement sheath. A micro-annulus can result in a misinterpretation of the CBL/VDL. Micro-annuli are caused by temperature, mud-cake deposits, pipe coatings and constraining forces. A common procedure is to pressure up the casing to approximately 1,000 to 1,500 psi and close the gap (if the cement job was good). Micro-annuli affect ultrasonic tools much less than the CBL/VDL and SBT (pads) in the presence of liquid in the gap with the opposite effect in the presence of gas.

Eccentralization. This may be an issue particularly in deviated and horizontal wells with the absence of cement on the low side and the distance between the casing and formation face is small.

Logging Tool Centralization. It is mandatory that the USIT and the CBL/VDL tools are well centralized. The SBT pads with their articulated arms are relatively unaffected by the centralization issue, although the CBL/VDL part of the tools is affected. Tool centralization can be checked in the log presentation.

Fast Formations. Formations with very high velocity and short transit time are called "fast formations". Acoustic signals from anhydrites, low porosity limestone and dolomites often reach

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the receiver ahead of the pipe signal. Fast formations affect the CBL/VDLs and SBT logs but do not affect USIT interpretation.

Lightweight Cement. Cement evaluation relies on the contrast in the acoustic properties of the cement and liquid. The acoustic properties of lightweight cement (commonly used in areas of weak formation) are close to those of cement slurry making it difficult to distinguish between the two.

Cement Setting Time. This is an important consideration in CBL interpretation. If the bond log is run before the cement is fully set, a misinterpretation indicating poor bonding may result in an unnecessary squeeze operation. The ultrasonic cement analyser (UCA) can be utilized to determine when to log and has shortened the WOC time.

Casing Shoe Pressure Testing

Casing shoe tests include formation integrity tests (FIT), leak-off tests (LOT), and pressure-integrity tests or pump-in tests (PIT) are carried out during the drilling phase after a string of casing has been cemented and a short section of new hole, typically 10 to 20 feet has been drilled.

Casing shoe tests serve the following purposes:

- To confirm the pressure containment integrity to ensure that no flow path exists to formations above the casing shoe or to the previous annulus. If such a flow path exists, and it extends to a formation without adequate integrity, the seal around the casing shoe may have to be repaired (e.g. by cement squeeze). (Failure of cement around the shoe is usually due to contamination, either from the original drilling mud or from the displacement fluid and usually results from poor cementing techniques rather than poor quality cements since hard-set neat cement has sufficient strength to withstand pressure tests).

- To investigate the capability of the wellbore to withstand additional pressure below the shoe such that the formation is competent to handle an influx of formation fluid or gas without the formation breaking down

- To collect in-situ stress data that can be used for geo-mechanical analyses and modeling (e.g. wellbore stability and lost circulation prediction).

Most governmental regulatory agencies maintain criteria regarding verification of casing shoe integrity. FITs are normally carried out in accordance with the operator's policy and procedure.

Well Integrity

During HF operations, wells that are hydraulically fractured can incur significant stresses, resulting in a potential loss of well integrity. A loss of well integrity may result in subsurface impacts or in a release of fluids to the surface, placing the public, workers, and the environment at risk.

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Definition of a Barrier: Envelope of one or several dependent well barrier elements preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface (NORSOK Standard D-010). The NORSOK Standard D-010 and API RP 90 define the primary well barrier as the first object that prevents flow from a source, and the secondary well barrier as the second object that prevents flow from a source. Examples of barriers include: tubing, packer and casing below packer; tubing, packer and casing above packer ('A'annulus); production casing, surface casing and casing shoe ('B' annulus).

The following recommendations are being made to ensure that HF candidate wells maintain their integrity (throughout their life cycle) and that operators have a documented HF risk assessment and risk management plan to manage the risks associated with hydraulic fracturing operations:

- An operator of a HF well must maintain well control at all times.

- The operator must design, construct, and operate its well with preferably a minimum dual barrier system (2-Barrier system) throughout its life cycle (pre, during and post-frac). Wells with a single barrier (1-Barrier system) are not recommended to be used for HF stimulation purposes.

- The primary barrier must be capable of containing and isolating the fracture fluids.The secondary barrier must be capable of providing well control in the event of a failure of the primary barrier.

- The internal pressure on each barrier must be monitored prior to the frac, during the frac, and after the frac job is completed, with the ability to detect and respond promptly to a barrier failure. If at any time during HF operations, the annulus pressure increases more than 500 psig, the regulatory agency needs to be notified within 24 hours and suitable corrective action taken by the operator.

- Casing must be designed to withstand the maximum burst and collapse loads anticipated during HF operations. When hydraulic fracturing through the production casing or through intermediate casing, the casing must be tested to 110% of the maximum anticipated surface treating pressure. If the casing fails the pressure test it must be repaired or the treatment has to be done through a fracturing string.

- If the HF is conducted through a fracturing string, the fracturing string must be stung into a liner or run on a packer set not less than 100 feet TVD below the cement top of the production or intermediate casing and tested to not less than 110% of the maximum anticipated treatment pressure minus the annulus pressure between the fracturing string and the production or intermediate casing.

- A pressure relief valve(s) must be installed on the treating lines between the pumps and the wellhead (with a remotely controlled shut-in device on the wellhead) so that the maximum anticipated treating pressure is not exceeded.

- The surface casing valve must remain open while HF is in progress and the annular space between the fracturing string and production/intermediate casing must be continuously monitored; the pressure in such annular space must not exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.

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- The operator's risk assessment and risk management plan (RA & M Plan) must assess and mitigate the risks of inter-wellbore communication between the HF well and an offset well.

- The RA & M Plan must include: (1) a HF program that includes target depths, well locations, well directional plans and anti-collision surveys, perforation or completion intervals, pumping rates, fluid volumes, pressures and fluid compositions; (2) the determination of a fracture planning zone (FPZ - a minimum of ¼ mile radius of the proposed wellbore trajectory and fracturing interval) and identification of offset wells within the FPZ; (3) an assessment of well integrity and a monitoring plan for each offset well such that if they transect the confining/treatment zones they will not provide a pathway for the treatment fluids to migrate; (4) geological data of known or suspected faults and fractures that may transect the confining zones and an assessment that these will not interfere with the containment of the HF treatment fluids ; and (5) a response plan in the event of inter-wellbore communication or loss of well control at an offset well.

- An operator's HF program must not impact the water quality and/or quantity of any groundwater and/or drinking water resources (USDWs). All USDWs within a ¼ surface mile of the FPZ must be identified and if the vertical separation between the top of the HF target zone and the base of the USDW/groundwater protection zone is less than 3000 feet then the RA & M Plan must minimize the risks and protect these aquifers from any consequences resulting from the HF operations. Suitable casing and cement design to prevent communication from the target HF zone into these aquifers should be incorporated in well construction.

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Oil and Gas Well Cementing

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Introduction

Cementing is one of the most critical steps in the drilling and completion (construction) of an oil or gas well. Well cementing technology is a combination of many scientific and engineering disciplines: chemistry, geology, physics, fluid mechanics, petroleum engineering, mechanical engineering, and electrical engineering. Each is essential to achieve the primary goal of well cementing – durable zonal isolation.

Primary Cementing

Primary cementing is the process of placing cement in the annulus between the casing and the formations exposed to the wellbore. In principle, primary cementing techniques are the same regardless of the casing string's purpose and size. The major objective of primary cementing has always been to provide zonal isolation in wells to exclude fluids in one formation from migrating to surface or another formation. To achieve this objective, a hydraulic seal must be created between the casing and the cement and between the formation and the cement, simultaneously preventing fluid channels in the cement sheath. Without complete isolation in the wellbore, the well may not allow stimulation operations to be conducted or the well to reach its full producing potential. Sufficient cement slurry must be pumped into the wellbore's annular space to fill it from the bottom to above the top of the productive formations. Typically, the cement slurry is brought to higher intervals to exclude undesirable fluids from the wellbore, to protect freshwater zones, and to protect the casing from corrosion. Primary cementing requires detailed engineering and application of the best available technology to achieve the desired operational results.

Cementing Design Considerations

Before the cement program can be designed, a well plan must be formulated. The well plan should take the well from drilling through plug and abandonment. There are many interconnected steps and operations that go into the drilling and completion of a successful well. Today the high cost of this process dictates that consideration be given to efficient and economical planning and execution without sacrificing wellbore integrity.

Developing a well plan is the same, regardless of the use of the well. Planning starts with the cooperation and information exchange among geologists, geophysicists, drilling engineers, completion engineers, operations engineers, superintendents, service companies, equipment providers, and government regulatory officials. Effective information exchange during the planning phase is critical to delivering safe and efficient results, and the collaboration often prevents operational issues during the drilling and completion of the well including adverse environmental problems that could result from an improperly designed or executed operation. Each functional operation during the well construction involves specialists. Effective communication among these specialists is paramount because often they do not have detailed

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working knowledge of all aspects of the well construction process, or a complete understanding of the full effects that their specific job may have on the other operations being conducted during the drilling and completion of a well.

During the planning phase, all of the following items must be analyzed and considered:

- Wellbore Environment
  - Well Location
  - Proposed Measured Depth and True Vertical Depth
  - Depth of Freshwater
  - Formation Temperature
  - Formation Pressure
  - Fracture Gradients
  - Natural Fractures
  - Hole Stability
  - Potential for Lost Circulation
  - Depletion
  - Salt Formations
  - Potential H_2S Containing Formations
  - Potential CO_2 or Other Corrosives
  - Fluid Production
  - Type of artificial lift
  - Tubing size

- Well Type
  - Vertical
  - Directional
  - Horizontal
  - Single Zone Completion
  - Multi Zone Completion
  - Injection or Disposal

- Casing and Cement
  - Surface
  - Intermediate
  - Production/Liner
  - Combination Casing Strings
  - Cement Systems

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- Mud System
  - Water Based
  - Oil Based
  - Salt Water Based
  - Synthetic Oil Based
  - Brine
  - Air
- Type of Completion
  - Horizontal
    - Plug and perforate
    - Sleeves with cemented or un-cemented casing
  - Vertical
    - Single zone
    - Multiple zones commingled
    - Multiple zones separated by packers
    - Stimulated
    - Gravel Packed
    - Barefoot or open hole

One of the primary considerations in the well plan, not just the cement job, is zonal isolation. All usable waters need to be protected from contamination during the drilling, completion, and producing phases of the operations. This requires careful design and construction of the well. Requirements include a drilling fluid program that prevents pressure invasion both to and from the wellbore, and a casing program that will withstand pressures and corrosive atmospheres that will be experienced during the life of a well. It also requires consideration of cement placement and elimination of any possible means of migration of fluids through or around the borehole.

The expected use of a well, whether it is production, injection, observation, or a multiple purpose well, will influence where the well is placed in a field, how large the casing is, and what corrosive service ratings will be required. It should be remembered that many wells serve more than one purpose during their lives.

The reservoir conditions will obviously affect the completion. The factors that are most commonly known are temperature and pressure. Other factors that should be considered are the type of fluids to be produced, viscosity, corrosiveness of the fluids, and the rate of production. Some important factors that are not always considered include the tendency for deposition of scales, emulsions, paraffin, and asphaltenes. It is possible by modification of the artificial lift system, the incorporation of special coatings, or the use of a good chemical treatment program to almost completely prevent the formation of scale or emulsions and the deposition of paraffin or asphaltenes.

The rate of fluid production is the main factor in selection of the casing size. Full production potential of high rate wells has to be met with large casing. Flow rate considerations are often in direct conflict with efforts to reduce well costs by using small casing or tubing strings. In many

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cases, the long-term benefits of larger tubulars outweigh the initial savings from a smaller casing program. Flow rates may warrant alternatives to conventional tubing and casing strings such as monobore completions, velocity strings, and tailpipe extensions.

Cementing operations must be carefully planned and executed to ensure proper placement and eliminate channeling of the fluid. It has been shown over the years that proper quality control and attention to detail results in effective primary cementing jobs.

Remember, every well that is ever drilled will require plugging and abandonment. The techniques and regulations are state specific, but the prevention of unwanted formation fluid migration within the abandoned wellbore is the underlying objective of all. Wells should be plugged in a manner in which the fluids that are in the reservoirs will stay isolated. This need for isolation should be an overriding concern in any completion planning and must be accounted for when processes such as fracturing or well placement are considered.

Cement Slurry Design

Basic Cement

There are many Types and Classes of cement that can be modified to work under varying well conditions. Portland cements are usually manufactured to meet certain chemical and physical standards that depend upon their application. Class A and Class C are normally used in shallow, low temperature applications. At circulating temperatures above 120°F API Class H or G cement is generally used. Each are designed to be basic cements for oil or gas well cementing in conjunction with additives used to modify the slurry properties. In some cases, additional or corrective components must be added to produce the optimum compositions. Examples of such additives are:

- Accelerators
    - Calcium Chloride
    - Sodium Chloride
    - Potassium Chloride
    - Sodium Silicate
- Retarders
    - Lignosulfonates
    - Cellulose Derivatives
        - Hydroxyethyl Cellulose (HEC)
        - Carboxymethyl Hydroxyethyl Cellulose (CMHEC)
    - Hydroxycarboxylic Acids
        - Citric Acid
        - Tartaric Acid
        - Gluconic Acid
- Extenders
    - Bentonite

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- o Pozzolans
- o Gilsonite
- o Perlite
- o Crushed Coal
- Dispersants
- Weighting Agents
  - o Hematite
  - o Ilmeite
  - o Barite
  - o Hausmanite
- Fluid Loss Additives
- Foams

Cements used in wells are subjected to conditions not encountered in construction, such as wide ranges in temperature and pressure. For these reasons, the API has established specifications for each type of cement. Oil and gas well cements are also available in either moderate sulfate-resistant (MSR) or high sulfate-resistant (HSR) grades. Sulfate-resistant grades are used to prevent deterioration of cement downhole caused from sulfate attack by formation waters.

The industry has nine major API classes of cement, hundreds of chemical additives and a number of special cements. These cementing products can be combined to meet almost any physical requirement. Below is listed the API Cement Classes available to the oil and gas industry:

Class A: For use from surface to 6000 ft. (1830 m) depth, when special properties are not required.

Class B: For use from surface to 6000 ft. (1830) depth, when conditions require moderate to high sulfate resistance.

Class C: For use from surface to 6000 ft. (1830 m) depth, when conditions require high early strength.

Class D: For use from 6000 ft. to 10,000 ft. depth (1830 m to 3050 m), under conditions of high temperatures and pressures.

Class E: For use from 10,000 ft. to 14,000 ft. depth (3050 m to 4270 m), under conditions of high temperature and pressures.

Class F: For use from 10,000 ft. to 16,000 ft. depth (3050 m to 4880 m), under conditions of extremely high temperatures and pressures.

Class G: Intended for use as a basic cement from surface to 8000 ft. (2440 m) depth. It can be used with accelerators and retarders to cover a wide range of well depths and temperatures.

Class H: A basic cement for use from surface to 8000 ft. (2440 m) depth as manufactured. It can be used with accelerators and retarders to cover a wider range of well depths and temperatures.

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Class J: Intended for use from 12,000 ft. to 16,000 ft. (3600 m to 4880 m) depth under conditions of extremely high temperatures and pressures. It can be used with accelerators and retarders to cover a range of well depths and temperatures.

Slurry Density

The maximum slurry density that will not fracture any weak zones should be determined. Generally, the designed slurry density should be approximately one pound per gallon (ppg) heavier than the mud but less than the minimum fracture gradient that could break down a formation. If more than one slurry is to be used, the density and viscosity differences between slurries should be taken into account. Below is a table listing various types of cement with their density ranges.

Cement Slurry Type	Density Range, ppg
Densified or Weighted	16 to 22
Neat	14 to 18
High Water Ratio	11 to 15
Ceramic Bead Extended	9.5 to 12+
Glass Bead Extended	7.5 to 12+
Foamed Cement	6 to 12+

Slurry Volumes

The quantity of slurry used should be designed to fill the annular area between the pipe and hole for the desired interval of coverage plus any excess to account for hole washout and possible contamination. If two slurries are used, the tail slurry volume should be sufficient to cover at least 300 to 500 feet of annulus above the shoe or a minimum of 500 feet above the producing interval.

Viscosity

The viscosity of a fluid is the ratio of the shear stress to the shear rate. Normally the unit of viscosity is centipoise; however in for oilfield cements the consistency of the slurry is measured in Bearden units (B_c). The Bearden a unit less number that API developed to rate the consistency of a fluid at a certain pressure and temperature that is transitioning irreversibly to a solid. The viscosity of the optimum cement slurry should range from 5 to 20 B_c. Slurries thinner than five B_c units will usually have excessive free water. Slurries with a viscosity greater than twenty units are often difficult to mix, using conventional methods.

Thickening Time

Thickening time is defined as the amount of time it takes from the initial mixing of the cement with water until it is no longer pumpable. At this point a consistency of 70 B_c has been obtained. The designed thickening time is usually based on the total time necessary to mix and displace the cement, plus a safety factor of one hour. In the field, thickening time translates to pumping time. This allows the field personnel to evaluate the transition time of the cement from a liquid through a gel state into a solid. Thickening time is a very important criterion for critical jobs where gas or

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fluid migration is a concern. Accelerators or retarders may be used in the cement to change the set time from a few minutes to many hours. A retarder is used in deep or very hot wells to prevent the set of the cement before the job is complete. Accelerators are used in shallow or cool wells to speed up the set of cement.

Compressive Strength

The slurry should be designed to minimize wait on cement time. Most authorities agree that a compressive strength of 1000 psi is adequate for drill out. For wells with a bottom hole static temperature in excess of 230º F, 35% silica flour or silica sand should be added to prevent strength retrogression.

Fluid Loss

Fluid loss of cement slurries should be designed and tested at bottom hole circulating temperature and 1000 psi differential pressure. The following guidelines should be used:

- Casing cementing - if fluid loss control is required because of permeability zones or water sensitive zones - 200-400 cc's/30 minutes

- Liner cementing - <100 cc's/30 minutes

- Squeeze cementing - 50-150 cc's/30 minutes

- Gas migration slurry - <50 cc's/30 minutes

Free Fluid

Free fluid should be less than 1% when tested at bottom hole cementing temperature for normal cementing operations. Zero free fluid slurry should be used in areas of known gas migration problems or in highly deviated and horizontal wellbores. Free fluid tests on critical jobs should be run at a 45º angle.

Lost Circulation

For casing jobs across known lost circulation zones, the use of Gilsonite, Sure Seal, or other lost circulation materials should be considered. Lost circulation material should not be used in liner cement slurries due to the small annular clearances. Also, when lost circulation material is to be used, care should be taken in choosing the float equipment and how the job is executed.

Control Slurry Segregation

This differs from free water in that there may not be visible signs of water separation, however, close evaluation of the cement will show significant variations in slurry density from top to bottom of the cement column. Slurries need to be designed to maintain their integrity and uniformity under downhole conditions.

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Cement Placement Mechanics

The following is a list of considerations that should be taken into account during the planning and execution of the cementing operation:

- Casing Hardware
    - Float Equipment
    - Stage Tools
    - Centralizers
    - Wiper Plugs
- Hole Conditioning
- Casing Rotation and Reciprocation
- Placement Procedures
    - Single Stage
    - Multistage
    - Liners
- Spacers and Chemical Washes

Important factors in obtaining a good primary cement job are

1. Good drilling practices and mud properties that provide for proper hole cleaning and the minimization of washouts are key factors in obtaining an excellent cement bond.

2. Pipe movement using both rotation and reciprocation is the best way to achieve excellent primary cementing quality. Even in low clearance holes, movement is critical. Unless the pipe is stuck, reciprocation can be accomplished with conventional surface equipment as well as numerous styles and types of centralizers. In order to rotate the pipe, the casing and centralizers have to be specifically designed for that purpose. A built-for-purpose rotating cementing head, coupled with a top-drive drilling rig is necessary for safe casing rotation.

3. Use of centralizers to keep the casing off the borehole wall is necessary. Programs are available from any of the cementing companies or centralizer vendors to aid in the placement and spacing of the centralizers for specific wellbore geometry and conditions. It is incumbent on the well site supervisors that they ensure that the centralizers are run as planned. Spiral, solid body centralizers can be very effective in highly deviated and horizontal wells, provided they do not restrict annular flow. Bow spring centralizers are rarely effective in anything but straight holes.

4. Optimal borehole to pipe clearance is critical. If one has a gauge hole, the cementing is greatly simplified. If the hole has washouts or is very rough it is much more difficult to get a good cement bond. Too little clearance also is problematic. For optimum cement circulation, attempt to get between ½" to 1" clearance all around the casing. For years industry has worked with rates, viscosities and flow regimes necessary to clean the mud

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cake before cementing to get an effective bond. Cementers have depended on washes and spacers to clean and disperse the mud filter cake. It has been found that clearances between borehole and pipe are critical.

5. Use spacers and/or flushes to isolate dissimilar fluids, prevent potential contamination problems, and help remove mud and mud cake from the well. Mud cake specific dispersants, pumped in turbulence and used with scratchers and pipe movement, are the most effective. Use enough spacer and/or flush to allow adequate contact time.

6. In formations with low frac gradients, cement slurries as low as 7.5 ppg have been very effective. It has been found that cement strength is greater than initially was thought possible. Eight-hour compressive cement strength of 1000 to 2000 psi is adequate to preserve an annular seal and these are typically achieved without issue.

Conditioning the Well and Displacement

1. Once the well has reached total depth the hole should be circulated to ensure that the well bore is clean and the mud conditioned properly before the drill string is pulled to run casing. Mud removal while cementing is closely related to the borehole quality resulting from the drilling operations.

2. Conditioning the mud properly is an extremely important aspect in obtaining a good cement job. The PV, YP and Fluid Loss of the mud need to be lowered to its optimum stable properties. If the mud exhibits progressive gels, these need to be eliminated prior to running casing. This will increase the displacement efficiency of the mud during, the conditioning of the well and prevent abnormal forces during pipe movement or breaking circulation.

3. Condition hole with good surface conditioned mud at highest possible rate without causing a problem with lost return.

4. Continue conditioning the mud and hole until a fluid caliper indicates at least 95% of the hole is being circulated. Cement will generally follow the path of the circulating drilling mud.

5. Determine hole volume, displacement volumes, wellhead pressures, bottom hole pressures, location of cement in the annulus, etc.

6. Measure returns with a trip tank or strapped tank or pit.

7. If wellbore conditions permit, reciprocate and/or rotate the casing to improve mud displacement. When combined, rotation and reciprocation can be a very effective mud displacement technique. However, drilling rig and surface equipment, along with wellbore conditions, often do not permit safe and practical casing movement. Casing rotation in directional and/or horizontal wells is vastly different from vertical wells and requires a tremendous amount of engineering and planning to implement.

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8. After casing is on bottom, begin reciprocation and mud conditioning immediately. Continue pipe movement until the cement begins to exit the shoe or abnormal drag/torque is encountered. Spot casing and continue the job until the plug is bumped or the calculated displacement is reached.

9. Calculate the swab and surge pressures to determine the maximum safe reciprocating speed.

10. Reciprocation of casing need not be fast; for example, one complete 15-foot stroke cycle, every one to three minutes is sufficient.

11. Due to free-fall phenomenon of cement in casing, mud return rate can exceed displacement rate if the well is on a vacuum. However, later in the job, the return rate can be significantly less than displacement rate as the free-fall rate slows down. This lower rate is not necessarily indicative of lost circulation.

12. It should be noted that the bottom cement wiper plug is another key element in the cementing operation. It serves two functions: it prevents the intermixing of the mud or spacers and the cement and it cleans the inner wall of the casing.

13. The top plug is run between the cement and the displacement fluid. Do not over displace. If the top plug has not bumped when properly calculated displacement volume has been pumped, shut down the pumps.

14. After bumping the top plug or shutting down, bleed off the casing pressure to determine whether the floats are holding. If the floats are not holding shut the well back in. A small amount of pressure increase can be expected because of fluid expansion and heat from the cement reaction.

Mud properties (for cementing):

Rheology

Plastic Viscosity (PV) < 15 centipoises (cp)

Yield Point (YP) < 10 lb/100 ft^2

These properties should be reviewed with the Mud Engineer, Drilling Engineer, and Company Representative(s) to ensure no hole problems are created.

Gel Strength

The 10-second/10-minute gel strength values should be such that the 10-second and 10-minute readings are close together or flat (i.e., 5/6). The 30-minute reading should be less than 20 lb./100 ft^2. Sufficient shear stress may not be achieved on a primary cement job to remove mud left in the hole if the mud were to develop more than 25 lb./100 ft^2. of gel strength.

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Fluid Loss

Decreasing the filtrate loss into a permeable zone will generally enhance the creation of a thin, competent filter cake (2 millimeters). A thin, competent filter cake created by a low fluid loss mud system is desirable over a thick, partially gelled filter cake. A mud system created with a low fluid loss will be more easily displaced. The fluid loss value for a vertical well should be < 15 cc/30 min (ideal would be 5 cc's). The fluid loss value for a horizontal well should be zero.

Circulation

Prior to cementing circulate full hole volume twice, or until well conditioned mud is being returned to the surface. There should be no cuttings in the mud returns. An annular velocity of 260 feet per minute is optimum (SPE/IADC 18617).

Flow Rate

Turbulent flow is the most desirable flow regime for mud removal. If turbulence cannot be achieved, pump at as high a flow rate as can be practically and safely used to create the maximum flow energy. The highest mud removal is achieved when the maximum flow energy is obtained.

Spacers and Mud Flushes

Spacers and/or flushes should be used to prevent contamination between the cement slurry and the drilling fluid. They are also used to clean the wellbore and aid with bonding. To determine the volume, either a minimum of 10 minutes contact time or 1000 ft. of annular fill, whichever is greater, is recommended.

Scratchers and Centralizers

Scratchers and/or centralizers should be attached with stop collars. Ensure that they are spaced out correctly.

Float Equipment

The float collar should be installed at least 40 feet above the shoe. This is to provide a reservoir to hold the cement contaminated by the mud wiped off the casing walls ahead of the wiper plug.

Cement Job Evaluation

Once the cement job has been performed it should be evaluated to determine if the objectives have been met. The objectives of the cement job need to be understood so that a proper job evaluation can be done. The main purpose for the cement job on the conductor casing is to prevent the circulation of drilling fluids around the casing and to the surface. The surface casing must be cemented to protect useable water formations and help support deeper casing strings. Intermediate casing strings are cemented to seal abnormally pressured reservoirs, isolate incompetent formations, and shut off lost circulation. Production strings are cemented to insure zonal isolation, prevent the migration of fluids in the annulus and to allow for well stimulation.

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Pressure testing is the most common testing method to ensure the mechanical integrity of the casing. It is generally performed after each casing string is set and before the casing shoe is drilled out. Once the casing shoe is drilled out then a shoe test is conducted to confirm the casing shoe will be able to withstand the anticipated mud weight for the next portion of the hole. After the production casing is run and cemented and before the completion begins, that casing string will be pressure tested. If the well is going to be hydraulically fracture stimulated the pressure test is usually run up to eighty percent of the rated casing burst. This is to insure that the casing integrity is intact for the completion.

In many wells a temperature survey will be run. If the temperature log is run at the appropriate time, an increase in temperature will indicate the top of the cement. A more thorough evaluation of the cement job can be done using various cement bond logs. During the last few years great advances have been made in cement bond logging tools. Instead of getting an average of the signal attenuation (cement bond) over the whole well bore, the tools can read small sections of the hole radially and give a much more precise picture of the quality of the cement job. Cement bond logs must be run under a very strict set of conditions and calibration; otherwise the log can be invalid. In addition, if the wellbore has been disturbed (trapped pressure bled off, pressure tested, fluid displaced, etc.) after the cement has set, a micro-annulus can be created that effectively breaks the acoustic coupling of the cement to the pipe. If the micro-annulus is not eliminated with the application of surface pressure during logging operations, the log results are invalid. Plus with the use of nitrogen foam, glass beads or other similar products cement bond logs can only be used as a qualitative tool.

Newfield Mid-Continent's Best Practices

Drilling

1. The well mud is being circulated until the drilling supervisor determines that he has the proper mud properties throughout the entire well bore and that the hole is clean.

2. The casing is run with the appropriate number and placement of centralizers.

3. Once the casing is on bottom the well bore and mud are conditioned again.

4. A Baker Swell Packer is run on the production casing to be set inside the intermediate casing string. This protects the well from fluids that may want to attempt to migrate up hole between the production casing and the intermediate casing.

5. During displacement of the oil-based mud a new Halliburton wash/spacer (TergoVis 1) is being used. It is designed to displace the oil-based mud with minimal intermingling with the mud and reduced hole stabilization problems. Additionally, the TergoVis will set up in the annular space above the top of the cement helping to stabilize and protect the casing.

6. When cementing, the casing is being either rotated, reciprocated or both. Halliburton's nitrogen foamed cement is being pumped at a weight sufficient to bring it up the hole above any potentially productive formations.

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Completions

1. The annulus pressure between the intermediate casing and the production casing is measured. If there is any pressure it is bled into a frac tank and checked for flow. The annulus is then pressure tested to 500 psi. The pressure is then released and the line remains connected to the annulus during the fracturing operation and pressure continuously monitored. Should pressure occur on the annulus, the fracturing job is shut down immediately.

2. The production casing is pressure tested to 80% of the yield of the pipe. Once the hydraulic fracturing crew is rigged up and pumping operations begin the casing injection pressure is continually monitored. Pop off valves and shut down switches are installed to immediately stop the pumping operation and relieve the pressure should it exceed a preset limit.

Conclusion

The oil and gas industry has been cementing wells for well over one hundred years. Many of the best practices discussed above have been used since the 1940's. To protect the fresh water and other resources in the communities where we operate and obtain the maximum lifetime value from our wells, it is incumbent for all of us in the petroleum industry plan and execute the best cementing practices available.

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Appendix B.

Extended Abstracts from Session 2:
Well Operation and Monitoring to Protect Drinking Water

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Wellbore Integrity: Failure Mechanisms, Historical Record, and Rate Analysis

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The statements made during the workshop do not represent the views or opinions of EPA.
The claims made by participants have not been verified or endorsed by EPA.

Introduction

Leakage of methane from oil and gas wells can have negative impacts on drinking water supplies (Taylor et al., 2000; Szatkowski et al., 2002; Van Stempvoort et al., 2005; Osborn et al., 2011) and increase greenhouse gas loading of the atmosphere (Howarth et al., 2011). Osborn et al. identified a correlation between the concentration of methane in private water wells in Pennsylvania and New York and proximity of such wells to the nearest natural gas well. That study also identified three possible mechanisms for explaining this correlation, and concluded that the most likely of these is migration from "leaky wells". A "leaky well" is one that has lost structural integrity and is allowing fluids in the rock strata crossed by the well to bypass the well itself and potentially enter an underground source of drinking water (USDW) and/or emit into the atmosphere. The purpose of the present study is to investigate further this possible methane migration mechanism. Methods for this study are, first, a brief description of mechanisms leading to leaky wells, second, a review of historical statistical data on occurrence of leaky wells, and, third, a detailed analysis of recent data on leaky wells in the Marcellus shale play in Pennsylvania.

Mechanisms for Loss of Structural Integrity

A comprehensive description of the various mechanisms by which oil and gas wells can develop fluid leaks can be found in Dusseault *et al.* (2000) and Robertson et al. (2012). A schematic of a simplified example is shown in Figure 1. The structural elements of a well are a set of casing strings, steel pipes of decreasing diameter installed to increasing depth, and layers of cement that can fill the annuli created between the drilled hole and each casing string. Only two strings are shown in this simple example; modern shale gas wells typically have 4 strings. One purpose of the cement is to act as a gasket around each casing string, with the objective of achieving successful "zonal isolation". In the example shown in Figure 1, zonal isolation means prevention of upward flow through the annulus of gas from a zone above the target reservoir. Modern cements are based on common Portland cement and water, with the possibility of various additives to reduce shrinkage and cracking during curing and to decrease permeability to gas flow. Placement of each layer of cement is sequential with deepening of a well and involves highly specialized equipment and procedures. Cement composition and placement are regulated at the state level for wells on private lands.

Successful zonal isolation places requirements on the cement to decrease the probability of many different cement failure mechanisms. Detailed description of these many mechanisms is beyond the scope of this paper but can be found in Dussault (2000). One requirement, shown failed in Figure 1, is that the cement bonds to both the outer surface of a casing string and the various rock

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types through which that string passes. Loss of such bond creates a fracture, sometimes called a micro-annulus, through which fluid may migrate upwards.
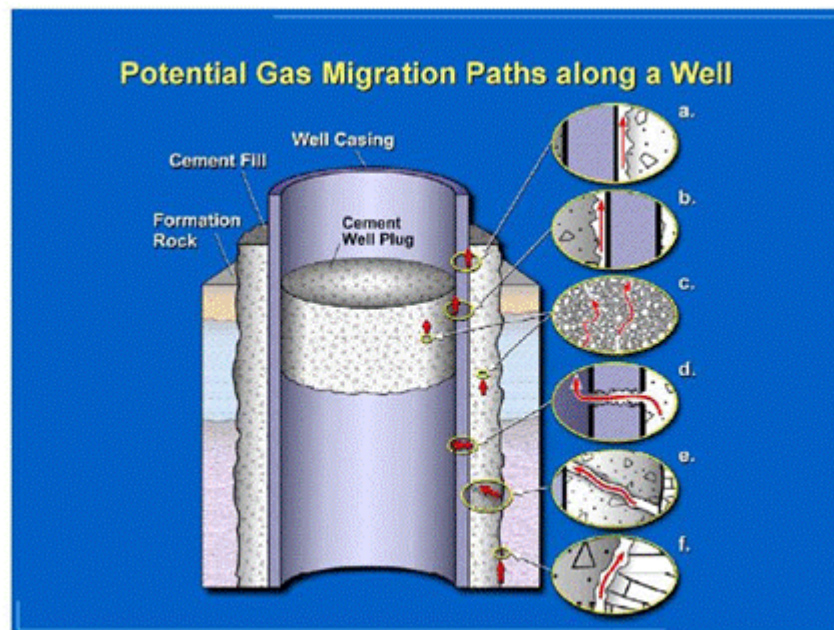
Repeated pressurization of a casing, open-annulus sections along a casing, high gas pressures encountering curing cement or entering such open-annulus sections are exacerbating factors leading to more rapid occurrence and upward growth of disbonding, in the rock-cement and /or the cement-casing interface.

These phenomena are not rare in the oil and gas industry. Data on failure rates for cement jobs leading to sustained casing pressure and possible fluid migration into USDW can be found, for example, in Figure 4 from Brufatto *et al.* (2003), who state:

> "Since the earliest gas wells, uncontrolled migration of hydrocarbons to the surface has challenged the oil and gas industry…many of today's wells are at risk. Failure to isolate sources of hydrocarbon either early in the well-construction process or long after production begins has resulted in abnormally pressurized casing strings and leaks of gas into zones that would otherwise not be gas bearing".
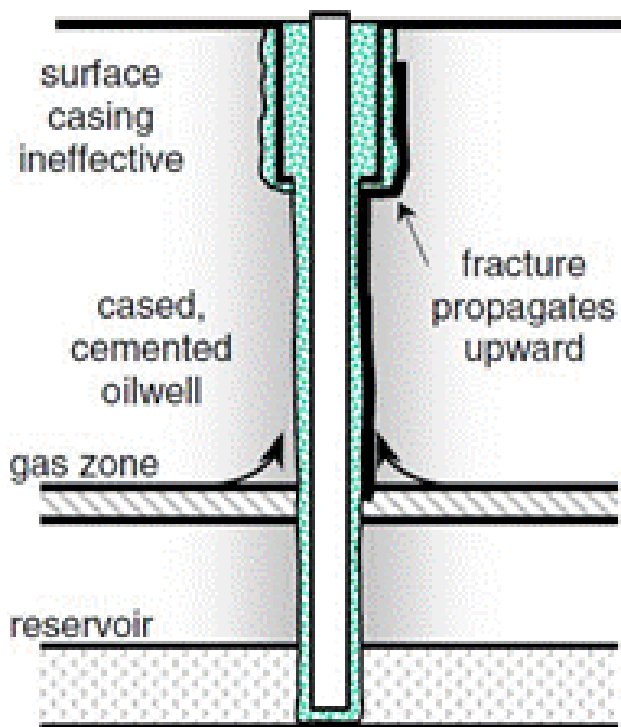
Figure 1. Schematic showing phenomenon of upward gas migration along a casing string resulting from cement-rock disbonding. From Dusseault *et al.*, 2000.

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Figure 2. Schematic of details of possible fluid migration paths in and around a cased/cemented well.
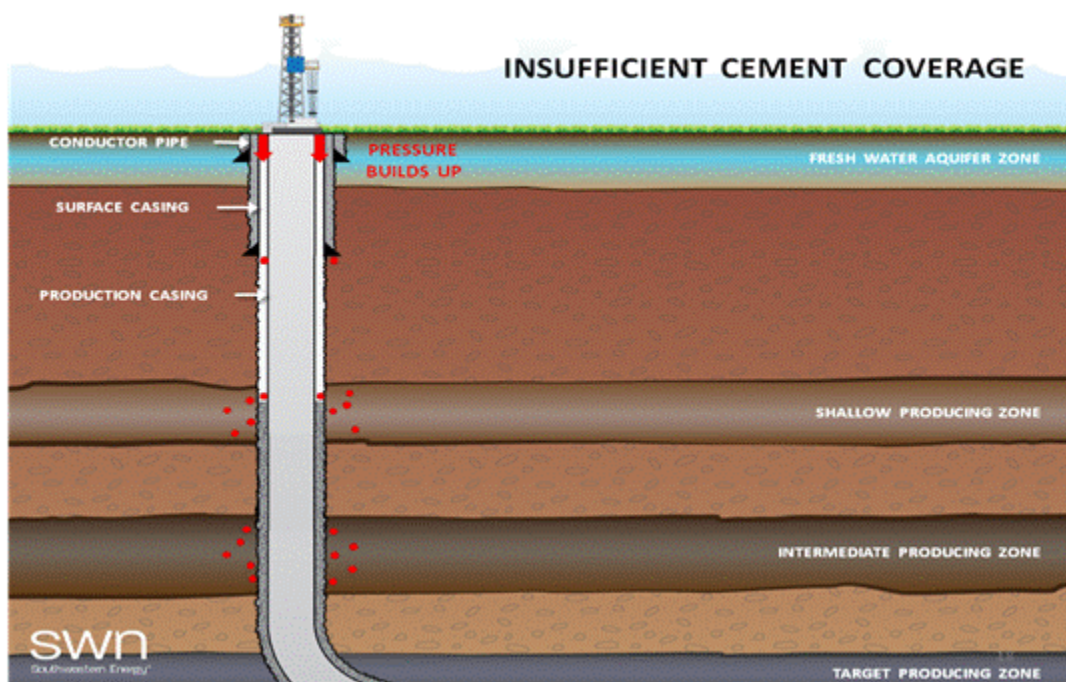
Figure 3. Depiction of entry of gas from a shallow source into an un-cemented annulus, leading to sustained casing pressure and migration of fluids into an USDW. From Boling (2011).

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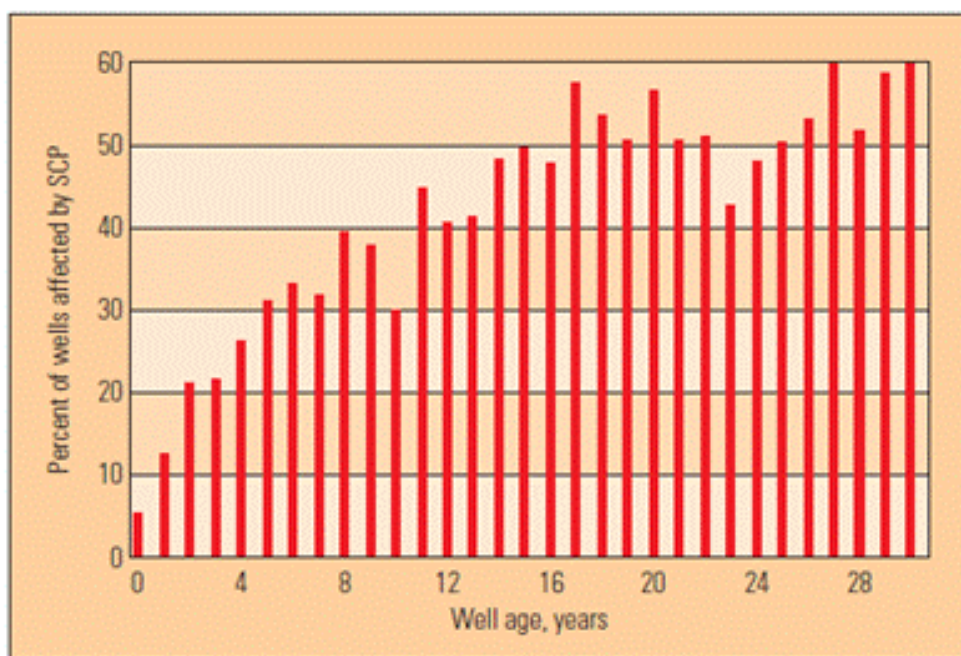
^ Wells with SCP by age. Statistics from the United States Mineral Management Service (MMS) show the percentage of wells with SCP for wells in the outer continental shelf (OCS) area of the Gulf of Mexico, grouped by age of the wells. These data do not include wells in state waters or land locations.

Figure 4. Data on frequency of occurrence of sustained casing pressure (SCP) in offshore wells. From Brufatto et al. (2003).
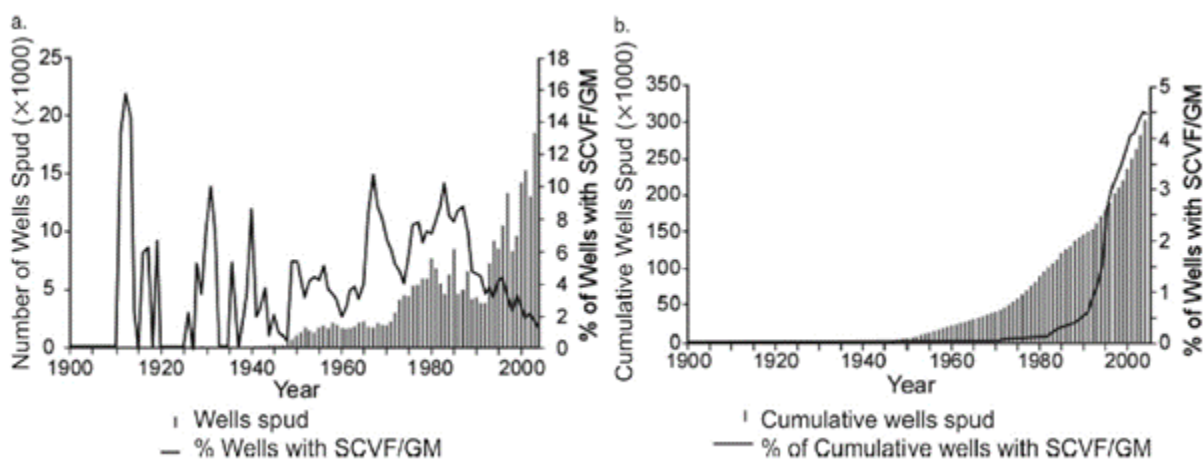
Figure 5. Data on frequency of occurrence of sustained casing vent flow (SCVF) or gas migration (GM). From Watson et al. (2009).

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In their statistical analysis of information about nearly 315,000 onshore oil and gas wells, Watson and Bachu (2009) state:

"Low cement top or exposed casing was found to be the most important indicator for SCVF/GM. The effect of low or poor cement was evaluated on the basis of the location of the SCVF/GM compared to the cement top... the vast majority of SCVF/GM originates from formations not isolated by cement."

Figure 5 shows data gathered by Watson and Bachu that is consistent for young wells with that shown in Figure 4. Watson and Bachu also present data that show a much higher rate of failure for deviated wells. It should be noted that, even with ongoing technological and chemistry improvements in cement and in cementing, loss of wellbore integrity is still common. A summary of the rate of well failure in the Pennsylvania Marcellus play since 2010 is presented below.

Prevalence of Fluid Migration from Faulty Wells

The science on contamination of drinking water from shale gas drilling, fracing, and production, is recent, ongoing, and incomplete. A peer-reviewed, archival journal study from Duke University (Osborne, *et al.*, 2011) found apparent migration of substantial amounts of methane from gas wells to private water wells as far out as 1000m in the Marcellus play in Pennsylvania. A more recent paper from the Duke University team (Warner *et al.,* 2012) documented geochemical evidence for possible natural migration of Marcellus formation brine to shallow aquifers in Pennsylvania. Also, the U.S. Environmental Protection Agency (EPA, 2011) recently released a preliminary report from an on-going study in Pavilion, WY, that suggests that substances used in fracing might migrate into adjacent water-bearing strata. The study also found clear evidence that there had been migration of methane from gas wells to nearby drinking water wells - likely caused by deficient cement jobs. Inadequate well construction and, of course, spills have been implicated in many states in a large number of cases of migration of drilling related substances into nearby drinking water.

Along with these fairly direct evaluations of the migration of methane and other substances, industry sources have asserted that private water wells are often contaminated by "naturally occurring" methane. This is often presented in an apparently analytical but confusing way, suggesting that the appearance of methane in drinking water wells is sort of "common" and thus unlikely related to any gas well drilling. Such presentation fails nearly entirely to, first, distinguish between dangerous/hazardous levels of methane in water (7 mg/L or more in PA), and much lower levels that are not generally taken to be of concern. Second, it ignores the prevalence or likelihood of having a dangerous "natural" level of methane in drinking water. Third, it ignores any time line: has there been any significant change in the concentration of methane concurrent with the beginning of nearby gas field development?

The New York DEC's data (NYS rdSGEIS, pg. 4-39) make clear that for a 2010 sample of water wells (n=46) in the "Delaware, Genesee, and St. Lawrence River Basins," presumably not near gas wells, just 2% of the wells had a dangerous level over 10 mg/L. One well had a level of 22 mg/L; the remaining wells then had an average level of 0.31 mg/L. This low percentage of "normal" risk has been confirmed repeatedly in studies in Pennsylvania, Figure 6; in the Southern

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Tier of NY (1450 water wells, USGS, 2010); in Alberta, Canada (360,000 wells, Griffiths, 2007); and by both independent investigations and by testing by gas drillers (e.g., Boyer, *et al.*, 2011). None of these findings suggest, in any way, that dangerous levels of methane are at all common in rural private water wells. Thus, a fairly strong implication is that, if and when methane does occur at high levels in water wells near gas drilling, it is likely due to some aspects of gas drilling, fracing and/or production operations themselves. This is consistent with both the Osborn, *et al.* (2011) study and the EPA Pavilion (2011) preliminary report. Exact migration mechanisms are not yet completely clear in each case, but the potential well failure mechanisms described in the previous section are often implicated.
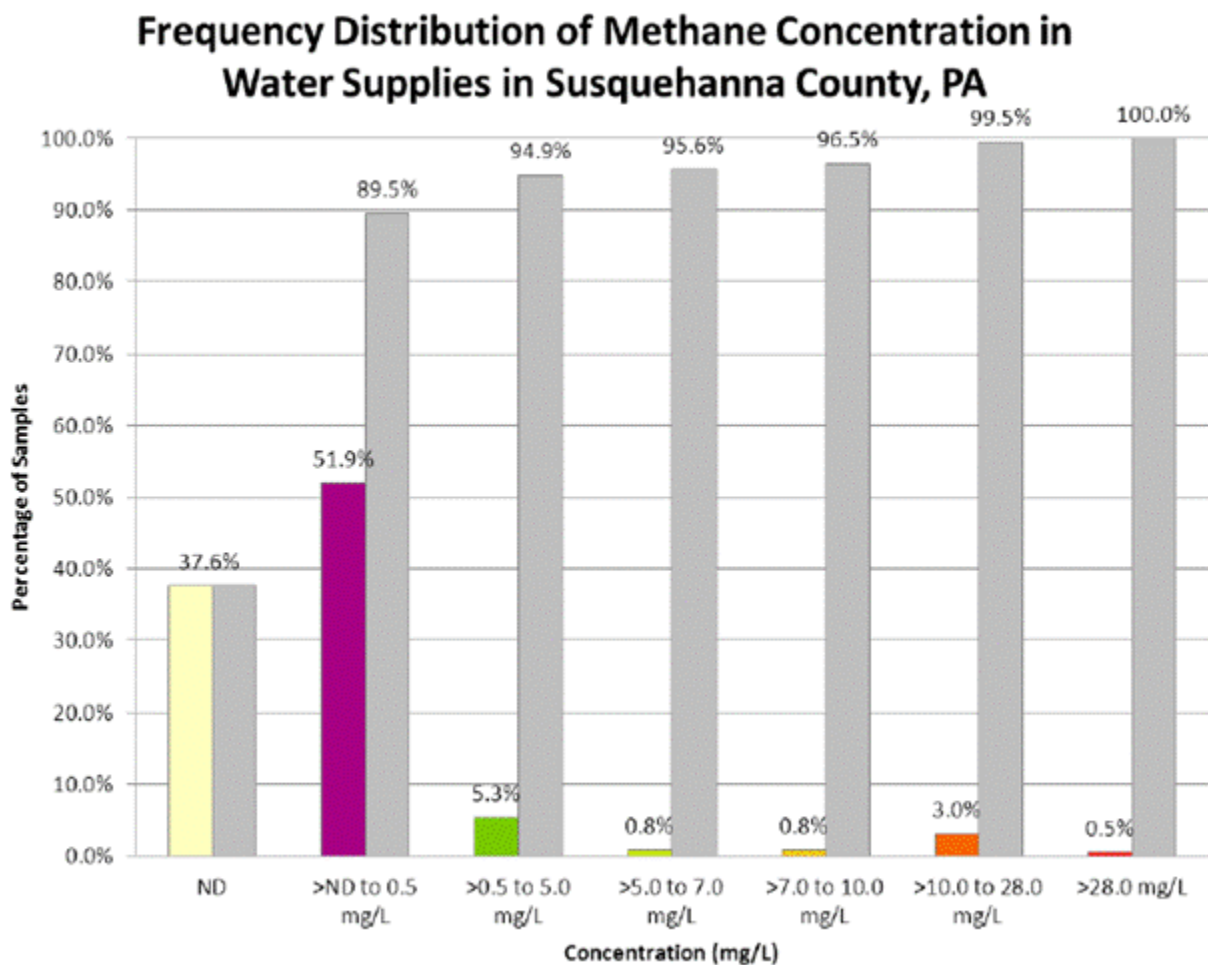
Figure 6. Data collected by PA DEP on methane concentration in private water wells in Susquehanna County, PA. 2433 water supplies were tested: 89.5% had concentrations of methane < 0.5 mg/L, 95.6% had concentrations of methane < 7.0 mg/L. Courtesy of Seth Pelepko, PA DEP.

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Recent Industry Performance in the PA Marcellus Play

A previous review of the PA DEP Marcellus Violations Database at
http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/O
G_Compliance resulted in the data shown in Figure 7. However, a recent re-review of this
database revealed that the data shown in Figure 7 are inaccurate. That data was obtained by
searching the violations database for all violations indicating that a well was leaking outside its
production casing. Table 1 shows all the violation codes used by PA DEP to indicate that a well is
leaking outside its production casing, why it might have occurred, and the consequences of such
failure. These were the codes used to filter the entire violations database to identify wells with
compromised structural integrity presented in Figure 7.

However, recently it has come to our attention that this filtering process results in a *lower-bound
on the number of wells with compromised structural integrity.* That is, more wells have failed
casings and/or cement jobs than have been reported through the violations shown in Figure 7. All
inspection reports for the more than 6000 wells drilled to-date in the Marcellus in PA were
reviewed; this is a more complete and revealing search than just filtering on certain violations.
The inspection reports indicate that many failed wells were not issued violations. Rather, they
received "Violation Pending" comments; or comments indicating that "squeezing", a cement
repair procedure which would only be done if a well was leaking outside its production casing,
had been done or was to be done; or comments that repairs were underway for a perforated
casing; or comments that gas was detected at the wellhead at or above the LEL (lower explosive
limit).

Table 2 shows the comparison for each of 2010, 2011, and 2012 between the numbers of wells
that had actually received violations, and those that were noted in inspection comments to be
leaking but had not received violations.


```
1,454  wells drilled in 2010.
      90 well failures.
    6.2% rate of failure.


1,937 wells drilled in 2011.
     121 well failures.
   6.2% rate of failure.


262 wells drilled in Jan/Feb 2012
    19 well failures
  7.2% rate of failure


Consistent with previous industry data,
      and not improving.
```

**Figure 7. Preliminary results of survey of leaking wells in the Pennsylvania Marcellus play based on
violations issued by the DEP. Violations data from
http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/OG
_Compliance**

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Table 1. Violation Codes Used to Identify Wells with Violations for Figure 7.

78.73A - Operator shall prevent gas and other fluids from lower formations from entering fresh groundwater.
78.81D2 - Failure to case and cement properly through storage reservoir or storage horizon
78.83A - Diameter of bore hole not 1 inch greater than casing/casing collar diameter
78.73B - Excessive casing seat pressure
78.83 GRNDWTR - Improper casing to protect fresh groundwater
78.83 COALCSG - Improper coal protective casing and cementing procedures
78.85 - Inadequate, insufficient, and/or improperly installed cement
78.86 - Failure to report defective, insufficient, or improperly cemented casing
207B - Failure to case and cement to prevent migrations into fresh groundwater

Table 2. Additional Counts of Wells with Loss of Integrity Included in Figure 8.

2010	64 wells with violations, 47 additional wells with loss of integrity noted in Inspection Comments
2011	97 wells with violations, 45 additional wells with loss of integrity noted in Inspection Comments
2012	44 wells with violations, 76 additional wells with loss of integrity noted in Inspection Comments

Figure 8 contains the revised well failure rates, using both actual violations and inspection comments to identify leaking wells. The complete database supporting the results shown in Figure 8 is available on request to http://www.psehealthyenergy.org/CONTACT.

Finally, it should be noted that a well that appears, at its wellhead, not to be leaking is not necessarily a sound well. It is well known that fluid migration can occur a significant distance away from the wellhead of a well that appears on inspection of only the wellhead to be of sound structural integrity.

Summary

The most recent experience with shale gas wells in the Pennsylvania Marcellus play reflects long term, world-wide industry data with respect to new wells with compromised structural integrity. Operator-wide statistics in Pennsylvania show that about 6-9% of new wells drilled in each of the past three years have compromised structural integrity. This apparently low failure rate should be seen in the context of a full buildout in the Pennsylvania Marcellus of at least 100,000 wells, and in the entire Marcellus and Utica plays, including New York, of twice that number. Therefore, based on recent statistical evidence, one could expect at least 10,000 new wells with compromised structural integrity. It is too early to discern whether the other industry experience with this technical problem, an increase in loss of integrity with well age, will also be reflected. However, at play in modern shale gas development are many of the key factors identified by

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industry researchers as having a negative influence on well structural integrity: the need for deviated wells, rapid development of a field, presence of "shallow" high-pressure gas horizons, and disturbance of young cement due to adjacent drilling activities on the same pad.

1,609 wells drilled in 2010.
111 well failures.
6.9% rate of failure.

1,979 wells drilled in 2011.
142 well failures.
7.2% rate of failure.

1346 wells drilled in 2012
120 well failures.
8.9% rate of failure.

Consistent with previous industry data,
and not improving.
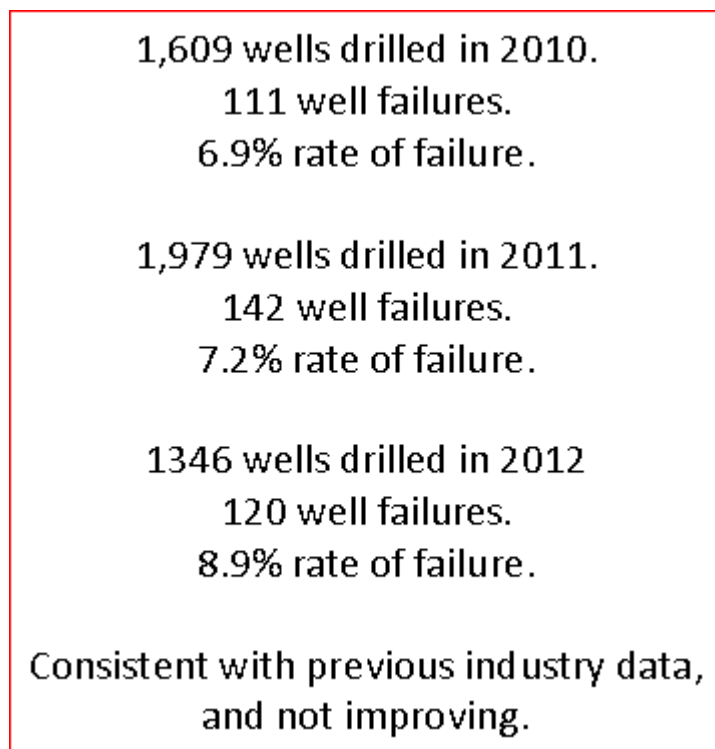
Figure 8. Revised results of survey of leaking wells in the Pennsylvania Marcellus play based on violations issued by the DEP and well inspector comments. Violations and comments data from http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/ Oil_Gas/OGCompliance

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Shell's Implementation of Process Safety & eWCAT
(electronic Well Control Assurance Tool)

Marco op de Weegh
Well Control & Design Integrity Team Lead
Shell Projects & Technology, Wells

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The claims made by participants have not been verified or endorsed by EPA.

Introduction/Background

This presentation and abstract will communicate Shell's implementation efforts of eWCAT (electronic Well Control Assurance Tool), which is part of process safety. Shell's HSSE & SP (Health, Safety, Security, Environment & Social Performance) Control Framework specifies governance for identified risks, to mitigate impact to people and the environment and to act as a good neighbor. Guidance is provided through standards and supporting documents, including manuals, guides, learning materials and assurance protocols. This framework outlines accountability and assurance requirements. Process safety is the management of hazards that can give rise to major accidents involving release of potentially dangerous materials, release of energy, (such as fire or explosion) or both. *(Baker Report,* Piper Alpha Platform, UK, North Sea, July 6, 1988*).* Through the application of the HSSE &SP CF and process safety, DEM 1 & 2 (Design Engineering Manuals), standards (DEM1) and PSBR's (Process Safety Basic Requirements, DEM 2) are utilized to existing and future assets to manage exposures. Examples for Wells DEM 1 standards are the pressure control manual (PCM) and casing tubing design manual (CTDM). There are currently 11 PSBRs, which indicate DEM 2 requirements. For Example, PSBR 11 was a result of the Macondo / DW Horizon incident. The eWCAT verifies compliance with internal and external requirements for well control integrity. The Well Control Model (WCM) identifies the minimum requirements for equipment utilized for well control, which are indicated by the DEM 1 Pressure Control Manual (PCM). The WCM, together with barrier verification plans, tests and verifies personnel competency and that equipment is documented in the electronic Well Control Assurance Tool (eWCAT).

The presentation accompanying this abstract during the EPA Technical Workshop on Well Construction/Operation and Subsurface Modeling will cover:

- HSSE & SP Control Framework (Health, Safety, Security, Environment & Social Performance)
- Process Safety, Wells Standards – DEM 1 & 2 (Design Engineering Manuals)
- Well Delivery Process & Bow-tie methodology
- PCM – eWCAT (Pressure Control Manual)
- Equipment, Personnel & Barrier Verification Plans (BVP)
- P&ID's (Process & Instrument Diagrams)
- COC & COS (Certificate of Conformance & Certificate of Service)

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Shell's Control Framework provides a structure and system to enable and consistently guide the organization. And, the framework is utilized to communicate with external stakeholders, including regulatory agencies. Shell's General Business Principles are at the core of the framework, which integrates leadership roles and responsibilities. Business opportunities are evaluated for risk exposure, assurance and compliance requirements to enable decisions for strategies, planning and appraisals. Clear lines of authority are established to support identified business opportunities to address internal and external requirements.

Process and personal safety requirements mitigate risk exposures throughout a well's life cycle. The following scopes are evaluated to ensure integrity for the wellbore and mitigate impact to the environment and those near our operations:

- Design integrity
- Technical integrity
- Operating integrity
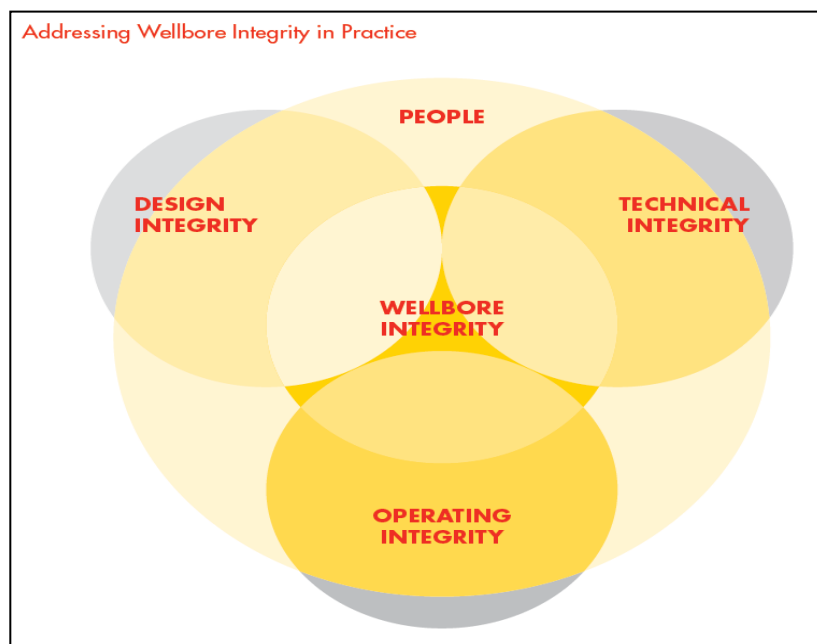
Figure 1. Process safety and addressing well bore integrity in practice

Lessons from industry incidents, caused by the unintended release of energy or hazardous substances, are integrated into our process and personnel safety methodology. Each well project includes an assessment of known and potential hazards associated with well control, well bore integrity, and containment. The following criteria are used to screen incidents and potential hazards:

- Loss of primary well control
- Design load case exceeded
- Single barrier failures or barrier events

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- Unintended release of well effluents
- Other relevant incidents

Hazard exposure and incidents are assigned risk criteria, indicated by a Risk Assessment Matrix (RAM) and based on severity, consequence and likelihood. Requirements and incident prevention criteria are documented in Design Engineering Manuals (DEM 1&2) and Well Standards (WS).

DEM2 specifically indicates Process Safety Business Requirements (PSBR) to prevent a re-occurrence of an incident. The following PSBRs are currently in place:

- PSBR 1   Safe locations of occupied portable buildings
- PSBR 2   ESD valves on platform risers
- PSBR 3   Temporary refuges
- PSBR 4   Permit To Work
- PSBR 5   Management Of Change
- PSBR 6   Avoid liquid release relief to atmosphere
- PSBR 7   Avoid tank overfill followed by vapor cloud release
- PSBR 8   Avoid brittle fracture of metallic materials
- PSBR 9   Alarm management
- PSBR 10   Sour Gas (H2S)
- PSBR 11   Deepwater Well Design and Construction

DEM1 are Design Engineering Practices (DEPs) and Wells Standards which indicate Shell's endorsement of best practices, industry standards and regulatory requirements.

Wells projects are subject to the guidelines & HSSE & SP Control Framework requirements. The Well Delivery Process (WDP) is utilized to mature the business opportunity and assigns key decision and review points for each Wells project, based on the HSSE & SP control framework requirements. Major exposures, indicated by top events, will be assessed on hazards and consequences by a bow-tie methodology.

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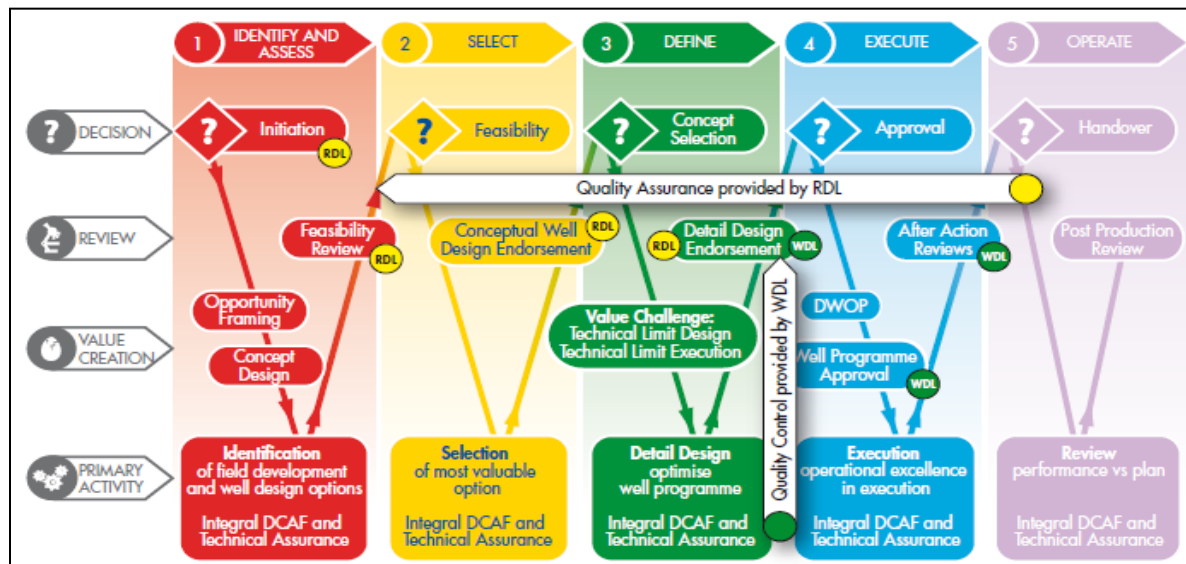
Figure 2. Well Delivery Process

The bow-tie methodology will indicate, based on the risk exposure, the barrier(s) in place to prevent the top event from exposure and the mitigation(s) needed to prevent further escalation. Based on the RAM indication, a minimum number of barrier elements or mitigation measures should to be in place to classify the risk exposure to As Low As Reasonably Possible (ALARP)
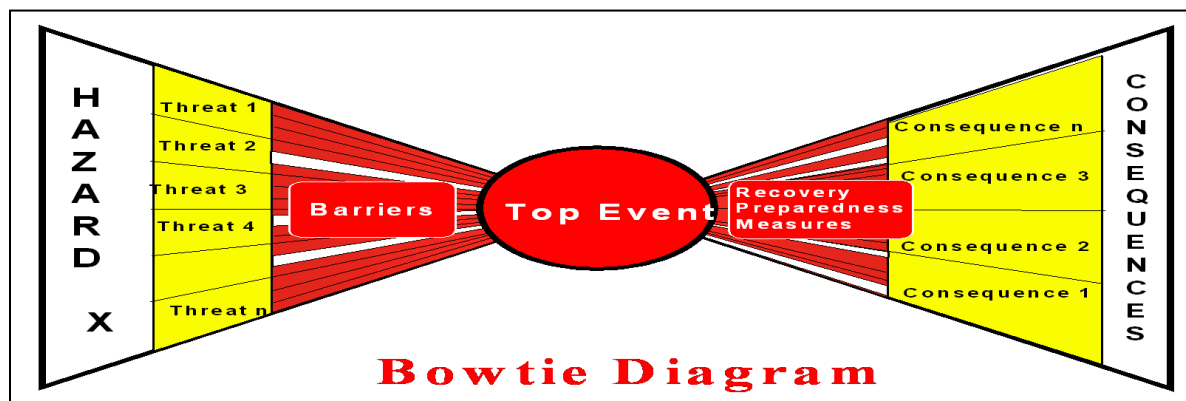
Figure 3. Bow tie diagram & methodology

During each phase of the Well Delivery Process, a project will be matured based on the criteria set in a Shell Decision Review Board (DRB). DRBs include Regional Disciplines Leads (RDL) and/or Wells Delivery Leads (WDL), which apply requirements set in the Project Controls & Assurance Plan (PCAP).

Shell is developing and implementing a monitoring system (eWCAT) for well control certification, including equipment and people, which will be utilized in a similar manner to the electronic Well Integrity Management System (eWIMS). The ultimate goal is to assure that all wells have integrity during the construction/maintenance phases (eWCAT) and during the operation phase (eWIMS). Well control compliance has three main elements:

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- Equipment certification and integrity verification,
- Personnel Well Control certification and competency, and
- Barrier Verification (plan and test).

The system will provide key metrics to monitor compliance, and it will use "traffic lights" to display a transparent view of the current status. It will also provide a consistent global framework and approach to well control compliance management. Validation will be supported by clear and simple workflows and tasks with due dates.
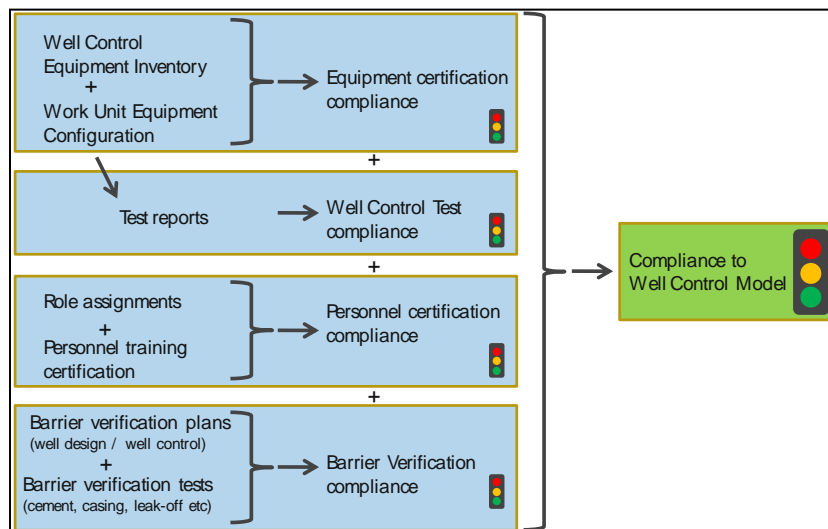
Figure 4. eWCAT elements and "traffic light" status indication.

Based on industrial trends, it is not sufficient to assume that contractors' procedures, around certification and testing, are adequate; nor can a contractual transfer of responsibility take place.

The implementation of electronic Well Control Assurance Tool (eWCAT) and endorsement of the Pressure Control Manual (PCM) will provide transparency and verification that our projects are controlled (barriers).

Implementing eWCAT will include the following scope:

- "Walk the line" from Mud Pumps to Mud Gas Separator (MSG) and identify equipment for the unit (document in upload template).
- Equipment identified will need verification of integrity by:
  - Certificate of Conformance (Industry standard, 5/10 years frequency as per API 6A/16A)
  - Certificate of Service (Performed maintenance, yearly, as per OEM recommendations)
- Document and verify well control competence of personnel:
  - Fundamental/supervisory level for either surface/subsea
  - Assistant Driller and up (Driller, Tool-pusher, DVS, Rig Manager, etc.)
- All company and contractor supervisory staff should hold a valid well control certificate from:

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- o International Well Control Forum (IWCF) or,
- o International Association of Drilling Contractors (IADC).

To enable eWCAT, the following steps are completed:

- Enter (load) equipment and personnel data into eWCAT (use of upload templates)
- Link the wells project (well events) in EDM (Engineers Data Model, the primary source of well data, including daily reports, cost, time, TA approvals, etc.) with eWCAT (work unit contract)
- Superintendent (Sr. Well engineer) to approve equipment and personnel scope completeness or gaps in relation to the Well Control Model (WCM)
- Wells engineer to load the Barrier Verification Plan (BVP) into eWCAT and indicate the verification test (for project scope)
- In case of non-compliance, initiate, process and approve the deviations in FSR (Facility Status Reporting) or derogation form (Technical Authority 1 approval)
- Provide updates to maintain the "traffic light green" compliance status by completing tasks as indicated in eWCAT.
- Complete all tasks prior to moving to next well project (new well event) and update data for the work unit contract (equipment, personnel and deviations)

Process & Instrument Diagrams (P&IDs) will enable the communications between all related stake holders involved in the eWCAT utilization. The P&IDs are a key enabler to identify equipment installed, barrier verification, and the tracking of any potential changes in equipment scopes. Serial or unique identification numbers on equipment with current or updated Certification (Certificate of Conformance or Service, COC/COS) will enable equipment integrity and barrier verification during the execution of Wells projects.

The criteria for Certificates of Conformance & Service are set in the PCM and in accordance to industry recognized standards and Original Equipment Manufacturers (OEM) specifications. The COC & COS enable the verification of equipment, as indicated by the quality assurance system, of the relevant standard and maintenance requirements of the OEM. Both types of certificates (COC &COS) are endorsed by an independent licensed entity, such as API (American Petroleum Institute) or an applicable industry/regulatory standard.

The verification of COC & COS enables compliance with the Shell HSSE & SP control framework requirements (when Process Safety requirements in DEM1 DEPs refer to requirements contained in external industry codes and standards, those requirements are also treated as mandatory).

Summary

Our industry will be exposed to a constant state of change. Process and personnel safety methodology, together with a HSSE &SP control framework, enables our organization to lead and manage changes in a responsible manner. In light of recent challenges, we have developed

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and implemented eWCAT to manage and make our integrity efforts transparent to all involved stakeholders and in line with our framework. Redundant and verified barriers, during all operational phases of well construction and operations, are an integrated requirement in our organization.

References

EP 2008 9088 Well Delivery Process

EP 2002 1500 Pressure Control Manual

699781 HSSE Making Wells Safer

Wells Global Functional Improvement Plan 2011

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Well Integrity and Long-Term Well Performance Assessment

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The claims made by participants have not been verified or endorsed by EPA.

Introduction

Wells are designed to safely extract or inject fluids in the subsurface and to prevent leakage of fluids from the target reservoir or any other geologic formation. Drilling the well perforates the rock and provides an avenue for fluids to migrate between formations including underground sources of drinking water (USDWs) and from the subsurface to the accessible environment. A combination of steel casing and Portland cement is used to create zonal isolation and prevent this fluid migration (Figure 1). Portland cement is injected into the annular space between the steel casing and the rock borehole and must form a complete bond between steel and rock to isolate fluid migration between the geologic formations and the surface.

Figure 1. Schematic diagram of well showing nested set of steel casing with Portland cement designed to prevent fluid movement outside the casing.

The first task in any well completion is to properly place the cement to achieve zonal isolation. This is challenging as the completion operations are conducted at the surface and the zones to be isolated are often at great depth and are hidden from direct observation. Acoustic instruments are used to try to verify zonal coverage by cement, but these methods are indirect and generally do not prove well integrity, although a satisfactory acoustic log is considered necessary to have demonstrated that zonal isolation has been achieved. The second task for the cement-steel system is to withstand the mechanical, thermal and chemical stresses present during wellbore operations and within the geologic formations. Wells are pressurized, de-pressurized and transmit relatively hot or cold fluids during normal operations. The local geology may impart tectonic stresses (e.g., mobile salt or shale) and contain corrosive formation water. Steel and cement must continue to isolate geologic formations while handling these stresses.

Why Do Wells Leak?

The failure to properly complete wells can arise by a variety of mechanisms (see Wojtanowicz 2008 for a review). These all involve the failure of the cement to completely span the annular space between steel and cement:

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1. Without proper centralization of the casing, cement may not fill the tight side of the borehole
2. Drilling without proper mud can result in formation caving and enlargement of the borehole that is difficult to fill with cement
3. Excessive pressure in the cement column can cause the cement to leak into the formation
4. Cement can lose water to the formation prior to setting fully or cement and water can separate leaving cement-free zones
5. Drilling mud must be removed fully to prevent contamination of cement and allow bonding to formation and steel
6. Formation fluids can mix with and contaminate cement
7. Cement can set in such a way as to allow intrusion of gas and formation of gas channels (Carter and Slagle 1972)
8. Bonding of cement to steel or rock may be inadequate
9. Cement can shrink during curing and separate from the casing or formation

This long list is compounded by the lack of tools that can definitively reveal poor well integrity before leakage damages the environment. The most promising and relevant tools are known as external mechanical integrity tests and include acoustic, temperature and radioactive tracer methods for detecting flow behind casing.

Post completion, wells are subject to mechanical, thermal and chemical stresses that can result in debonding of the cement-casing or cement-formation interfaces, fracturing of the cement, or chemical degradation of cement and/or steel. Well operations, including internal mechanical integrity testing, change the pressure inside the casing resulting in expansion or contraction that can damage the cement or its interfaces with steel and rock. In the case of hydraulic fracturing, the wells can experience either very high internal pressure during fracture stimulation and/or high-pressure traveling along the outside of the casing. Thermal effects due to production or injection of fluids can have a significant mechanical impact through differences in thermal expansion of steel, cement and rock as well as transients in thermal equilibrium. Finally, fluids and gases can attack the steel and cement and degrade their mechanical or hydrologic properties. CO_2 and H_2S are highly corrosive to carbon steel that is typically used in well construction and both of these gases react with and can be harmful to Portland cement. In addition, formation fluids can result in sulfate attack on cement and acid stimulation practices can expose cement and steel to corrosive fluids.

With all of these potential problems, it would seem that well integrity is rather difficult to achieve. However, one mitigating factor is that zonal isolation can be achieved with a relatively small thickness of cement. Thus in a well with a 100 m or more Portland cement, a mere 1 m of this across an impermeable caprock can prevent fluid migration.

Field, Experimental and Computational Studies of Well Integrity

The following review will emphasize experience obtained during investigations of the integrity of CO_2 sequestration wells. In these studies, the primary objective was related to the chemical

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stability of Portland cement and steel but many of the observations and approaches are applicable to understanding integrity in hydraulic fracturing wells.

Detailed sampling and logging of old wells has provided direct observations on the physical state of wells (Figure 2). Well materials from a CO_2-enhanced oil recovery (EOR) field in west Texas showed several features relevant to well integrity (Carey et al. 2007): 1) Cement had survived 35 years in a CO_2 environment and continued to provide substantial barrier to flow; 2) evidence for CO_2 migration was observed along the cement-casing and cement-formation interfaces; 3) steel casing was in good condition; and 4) cement fractures were observed but had healed by carbonate precipitation.
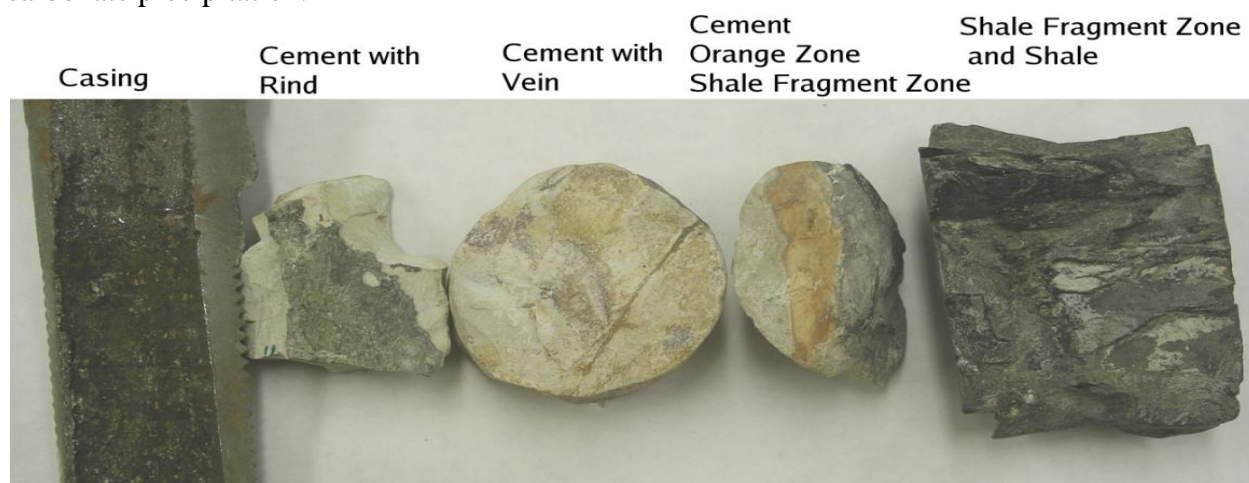
Figure 2. Samples recovered from a side-track drilling of a 1974 CO_2-EOR well located in the SACROC field, west Texas. The dark rind is a carbonate deposition zone at the cement-steel interface; the vein in the cement is a healed fracture; the orange zone resulted from diffusion of CO_2 into cement at the cement-formation interface. From Carey et al. (2007).

The primary focus of the SACROC study was on the chemical stability of cement in CO_2 environments, but the study revealed the importance of interface flow mechanisms and the ability of cement to self-heal through precipitation. This was observed in cement fractures but also at the interfaces where carbonate precipitation occurred. In the absence of CO_2, cement fractures have been observed to close by mineral deposition in studies by Huerta et al. (2013) and in studies of flow of CO_2-saturated through cement (Bachu and Bennion 2009; Wigand et al. (2009); Laudet et al. 2011). Several studies have also observed reduction of permeability during flow of CO_2 and water or CO_2-saturated brine through cement-casing interfaces (Carey et al. 2010) and through cement-rock interfaces (Newell and Carey 2013; Walsh et al. 2013). However, the capacity of cement systems to heal under all conditions has not been established, particularly in systems without CO_2 (e.g., Yalcinkaya et al., 2011).

Computational modeling of the chemical reactivity of cement systems provides a basis for predictions of mineralogical stability in wellbore environments. Recent advances in thermodynamic databases and their application of have improved the potential for more accurate calculations of cement degradation (Matschei et al. 2007; Lothenbach et al. 2008). An example calculation of CO_2 attack of cement is shown in Figure 3 and illustrates the transformation of

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Portland cement phases to calcium carbonate and amorphous silica, alumina, iron hydroxides (Carey et al. 2007). Other examples of cement modeling applied to CO_2 sequestration include Huet et al. (2010), Gherardi et al. (2012), Jacquemet et al. (2012) and Wertz et al. (2013).
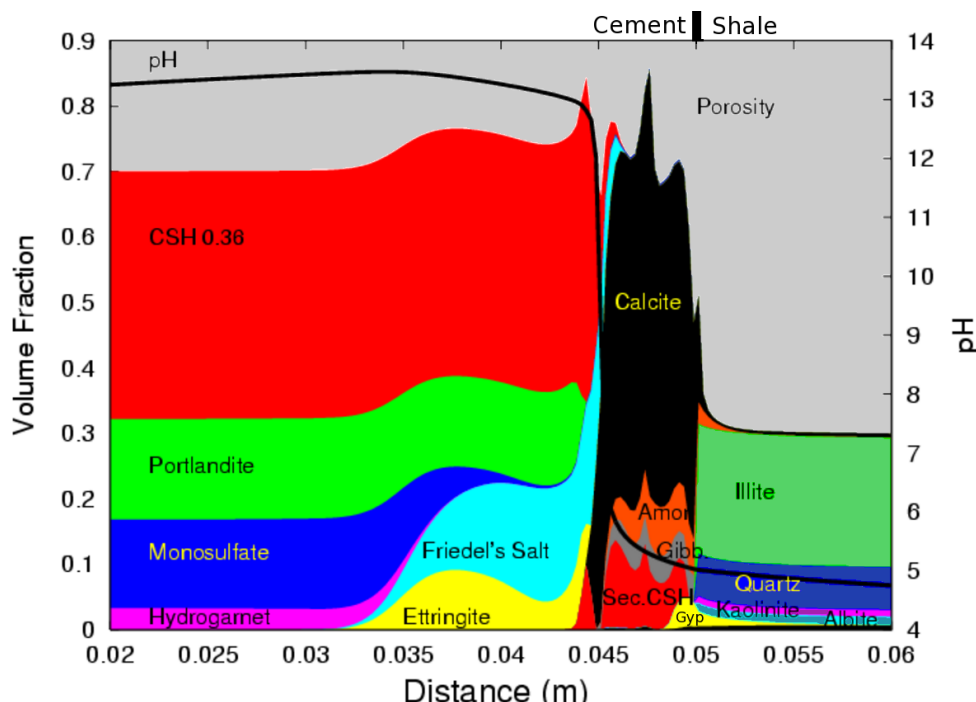
Figure 3. Computational model of cement carbonation. Unaltered cement on the left is attacked by CO_2-saturated water diffusing in from shale caprock on the right. The result is after 30 years of reaction and shows a 0.5 cm zone of carbonated cement. From Carey et al. (2007).

The reactive transport models provide useful insights into cement stability but they do not directly address the hydrologic or mechanical properties that are critical to the determination of zonal isolation. Additional work is needed to couple the chemical models with impacts on permeability and the development and healing of fractures.

There has been comparatively less work on the geomechanical behavior of wells, at least in sequestration applications. Work by Liteanu et al. (2009) and Gabezloo et al. (2009) illustrates the plasticity of Portland cement at elevated confining pressures. This has important implications with respect to whether cement develops fractures in response to stress as well as the permeability of fractures and defects in cement. If cement deforms following defect creation, then fractures and interfaces are unlikely to remain open and transmissive. In particular, cement mechanical properties should provide limits on the maximum microannulus aperture that cement can support. The geomechanical response of cement is of particular importance to hydraulic fracturing due to the large pressure perturbations required to fracture rock.

Portland cement protects steel from corrosion. However, many well completions do not include complete coverage of steel by cement and regions of exposed steel should be evaluated for potential exposure to corrosive formation fluids. If the cement-steel bond is poor and fluids migrate along the interface, corrosion can be significant. For example, Carey et al. (2010)

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investigated the effect of CO_2 at the steel-casing interface and showed that steel corroded more significantly than cement carbonated, but this was mitigated by the precipitation of iron carbonates at the interface (Figure 4). Recent work on CO_2 sequestration has involved development of corrosion models applicable to subsurface conditions that include high salinity brines (Han et al. 2011).
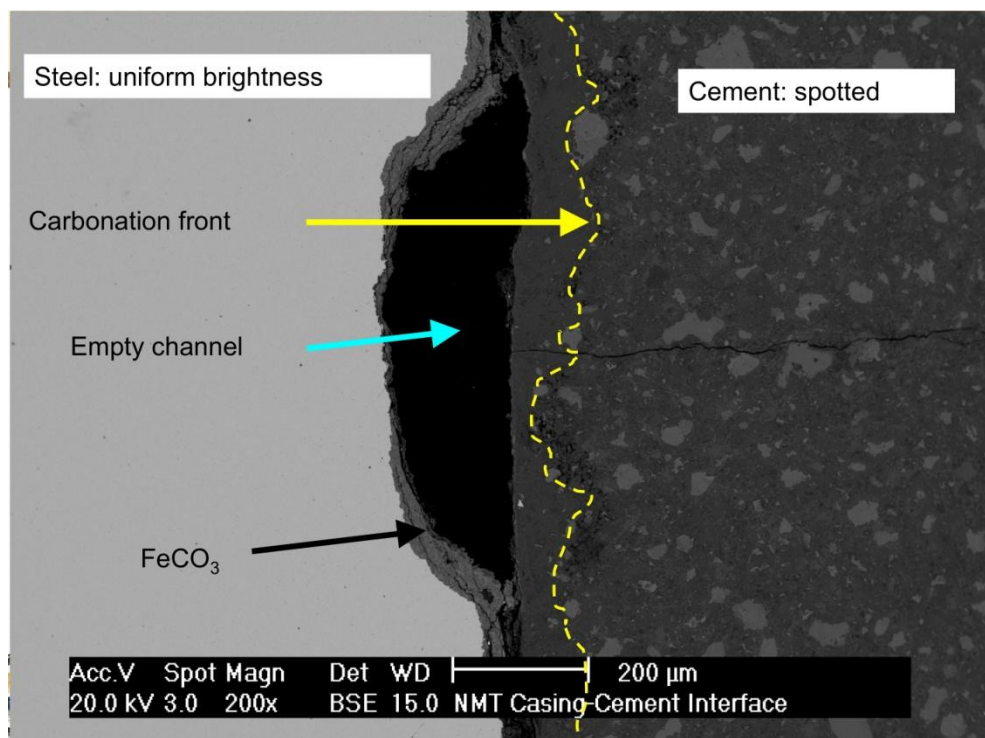
Figure 4. Corrosion of steel and carbonation of cement in a coreflood experiment simulating the steel-cement interface in a well. From Carey et al. (2010).

Key Results from CO$_2$ Sequestration-Related Work

- Gas migration is dominated by transport at interfaces between cement and steel or cement and formation rather than by flow through the cement matrix
- Portland cement has substantial self-healing properties related to mineral precipitation at interfaces and potentially through plastic deformation
- Cement protects steel from corrosion; where flow occurs at the cement-steel interface, corrosion of steel can be a more rapid process than cement degradation
- Cement mechanical properties at reservoir depths may be sufficiently plastic to limit fracture development or microannulus width.
- Cement geomechanical properties at elevated pressure are a key but inadequately known aspect of maintaining zonal isolation during hydraulic fracturing

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Open Questions Regarding Well Construction and Hydraulic Fracturing

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The claims made by participants have not been verified or endorsed by EPA.

Hydraulic fracturing of wells began in the oil field as a method to stimulate oil and gas wells, and was first used in 1947. Since that time, hydraulic fracturing of oil wells has been practiced in thousands of wells. The process of hydraulic fracturing creates fractures that extend from a borehole into the producing formations. Proppants are injected into the fractures, preventing the fractures from closing after the injection pressure is reduced. Proppants are typically sand or resin-based materials. The fractures with permeable proppants provide highly-transmissive pathways to the borehole, exceeding the normal permeable pathways through the native formation materials.

Hydraulic fracturing, combined with horizontal drilling technologies, has allowed for the development of oil and gas reserves that have not been economically developable using only vertical well construction techniques. As the use of these technologies (hydraulic fracturing and horizontal drilling) has increased, concerns over ground and surface water contamination have developed. However, the term "fracking" has been used to not only identify the process of hydraulic fracturing, but also to include all aspects of well drilling, construction, and production. This has lead to the incorrect correlation between contamination and the singular process of hydraulic fracturing. In addition, this incorrect correlation has impacted other areas of natural resources development, specifically with geothermal and water supply well construction. Hydraulic fracturing of geothermal and water supply wells has been adversely impacted by the public's reaction to the term and process of hydraulic fracturing. Hydraulic fracturing of potable water supply wells has been conducted for several decades using clean water technologies. However, recent water supply and geothermal well projects that would have benefitted by the use of hydraulic fracturing technologies were impacted by public concerns regarding the use of the technology.

To date, there has not been any direct correlation between groundwater contamination and the singular process of hydraulic fracturing. However, there have been oil and gas well sites with contamination of surface and ground water. Identification of the causes of the contamination have generally been related to incorrect or improper well construction and the lack of control of drilling or hydraulic fracturing fluids at the surface within the well site boundaries. Therefore, identifying and mitigating contamination associated with oil and gas drilling and construction activities should be focused in these areas.

Discussing and addressing several open questions related to well construction and hydraulic fracturing will assist in guiding the future investigation and research of potential impacts from oil and gas development with specific focus on hydraulically fractured wells. Some of the potential open questions are as follows:

- How do you define hydraulic fracturing with respect to well construction?
- When should baseline ground and surface water quality samples be collected?

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- How and what ground and surface water quality data should be collected?

- What information (well construction, abandonment procedures, etc.) and testing is required for existing (offset) wells completed through producing intervals to be hydraulically fractured?

- What are the criteria for groundwater monitoring wells (existing wells or new wells with verifiable construction methods)?

- How should Underground Sources of Drinking Water (USDW) be identified (geophysical logging, physical testing, or other alternative methods)?

- Do all wells within an oil and gas development field need to test potential USDW's or a representative number?

- What is the required depth and type of surface casing, what types of cementing requirements should be considered for oil and gas wells to prevent possible contamination to USDW's, and does this change from field to field?

- How do you verify cement grout seals during or after well construction (cement bond logs, cement evaluation tools, temperature logs, etc.) and should all wells be required to verify the cement seal?

- Should Mechanical Integrity Tests (MIT) be conducted on surface casing strings that are completed through USDW's?

- How does time factor into all aspects of well construction and monitoring (pre-development, construction, production, and abandonment)?

- Does the use of "green" fluids in hydraulic fracturing change the approach to well construction, inspection, and monitoring?

- What controls are effective to mitigate surface spills (close-looped systems, whole-site spill prevention measures, etc.)?

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Appendix C.

*Extended Abstracts from Session 3:
Subsurface Modeling*

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Evaluating Scenarios of Potential Subsurface Impact Using Computational Models

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Information presented in this abstract is part of the EPA's ongoing study. EPA intends to use this, combined with other information, to inform its assessment of the potential impacts to drinking water resources from hydraulic fracturing. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

Introduction

The US EPA Hydraulic Fracturing study is evaluating the question "Can subsurface migration of fluids or gases to drinking water resources occur, and what local geologic or man-made features might allow this?" The US EPA Office of Research and Development, through Interagency Agreement with the Department of Energy's Lawrence Berkeley National Laboratory (LBNL), is conducting an investigation of the potential impact of injection and the fracturing process on drinking water aquifers. Dr. George Moridis is the LBNL research team leader. The project is using numerical simulations to investigate possible mechanisms that could lead to upward migration of fluids, including gases, from a shale gas reservoir to a drinking water aquifer, and the conditions under which such hypothetical scenarios may be possible. A more complete description of the project is included in the US EPA Progress Report (US EPA, 2012, Section 4.1).

An outline of the project critical path is shown in Figure 1. After a thorough review of the scientific literature and data, and interviews with a selection of experts on the topic, a finite number of plausible scenarios were selected for more quantitative assessment. These scenarios basically included two major possible pathways: (1) wells, either the production well itself or offset wells such as abandoned oil and gas wells (see Moridis et al., 2013); and (2) geologic features such as faults and fracture zones. The investigation is ongoing in two concurrent tracks. The first track is investigating the geophysical factors involved in establishing a pathway connecting the tight gas reservoir to the drinking water aquifer. Because the possibility of a pathway or combination of pathways cannot be ruled out, a separate track of research is investigating the factors influencing fluid migration, whether of methane gas, displaced native brines, or introduced hydraulic fracturing fluids (see Freeman, Moridis, 2013).

The initial scenarios include (see Figure 2):

Scenario (a): Defective or insufficient well construction coupled with excessive pressure during hydraulic fracturing operations results in damage to well integrity during the stimulation process. A migration pathway is then established through which fluids could travel through the cement or area near the wellbore into overlying aquifers. In this scenario, the overburden is not necessarily fractured.

Scenario (b): Fracturing of the overburden because inadequate design of the hydraulic fracturing operation results in fractures allowing fluid communication, either directly or indirectly, between shale gas reservoirs and aquifers above them. Indirect communication would occur if fractures intercept a permeable formation between the shale gas formation and

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the aquifer. Generally, the aquifer would be located at a more shallow depth than the permeable formation.

Scenario (c): Similar to Scenario B1, fracturing of the overburden allows indirect fluid communication between the shale gas reservoir and the aquifers after intercepting conventional hydrocarbon reservoirs, which may create a dual source of contamination for the aquifer.

Scenario (d): Sealed/dormant fractures and faults are activated by the hydraulic fracturing operation, creating pathways for upward migration of hydrocarbons and other contaminants.

Scenario (e): Fracturing of the overburden creates pathways for movement of hydrocarbons and other contaminants into offset wells (or their vicinity) in conventional reservoirs with deteriorating cement. The offset wells may intersect and communicate with aquifers, and inadequate or failing completions/cement can create pathways for contaminants to reach the ground water aquifer.
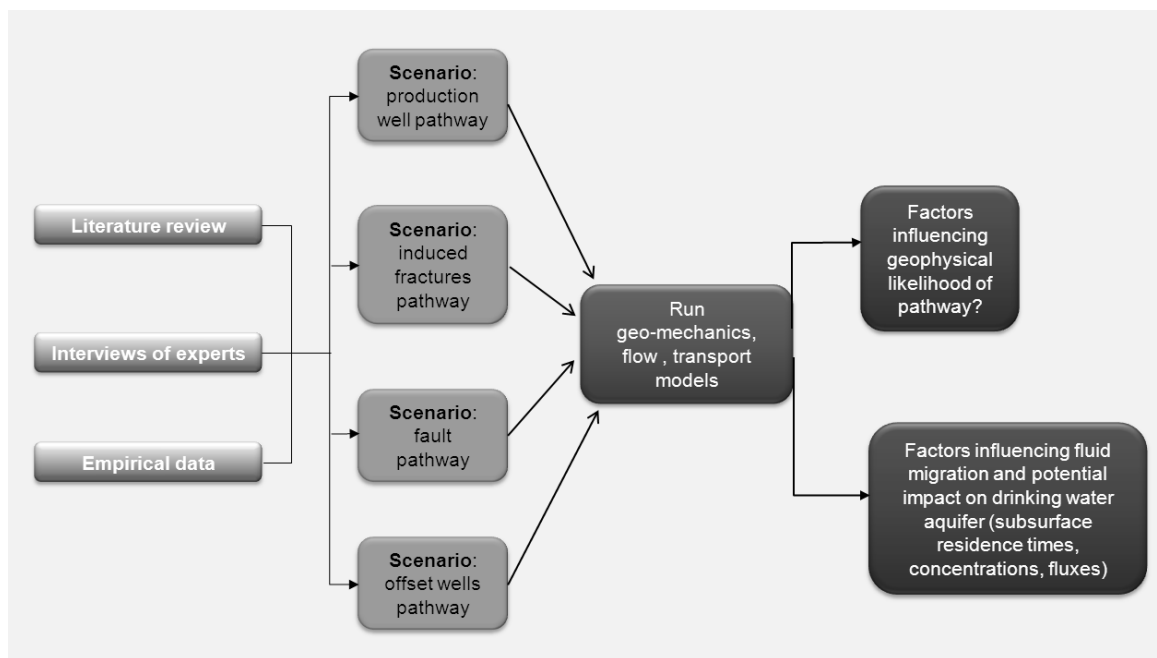
Figure 1 Critical path for subsurface impact assessment.

There is no single numerical model that includes all of these processes. Thus, the EPA-LBNL team chose to build off of the Transport of Unsaturated Groundwater and Heat (TOUGH) family of codes (Moridis et al., 2008) in combination with the existing modules listed in Figure 3 to create a modeling system that simulates the subsurface flow and geomechanical conditions encountered in the hydraulic fracturing migration scenarios. TOUGH was developed at LBNL in the early 1980s and the suite of simulators are now widely used at universities, government organizations, and private industry. The LBNL selected computational codes are able to simulate the flow and transport of gas, water, and dissolved contaminants concurrently in fractures and porous rock matrices. The numerical models used in this research project couple flow, transport, thermodynamics, and geomechanics to produce

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simulations to promote understanding of conditions in which fluid migration occurs. A complete list of references documenting the code development is included in the US EPA Progress Report (US EPA, 2012).
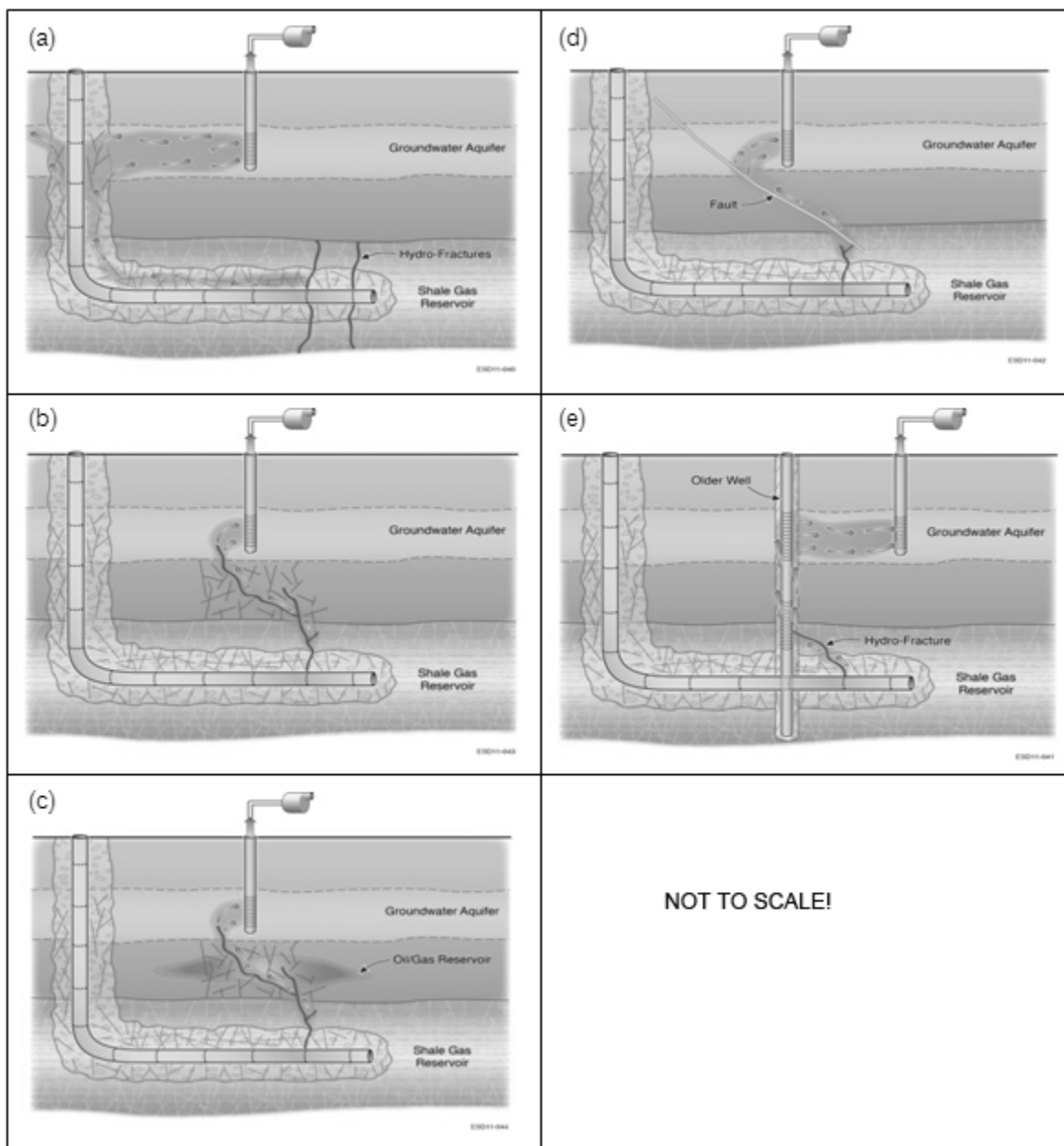
Figure 2 Hypothetical scenarios of potential pathways connecting shale gas reservoirs with aquifers under investigation.

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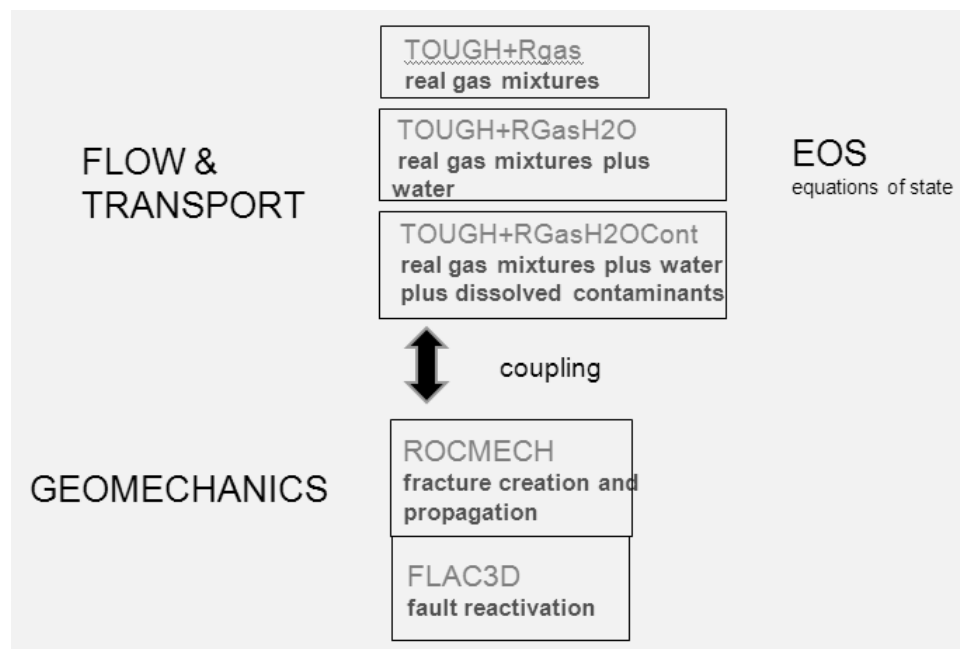
Figure 3 The LBNL TOUGH+ family of codes supporting the project.

Summary

The subsurface migration modeling project is proceeding along two concurrent tracks. The first addresses the geomechanical reality of mechanisms and seeks to determine the likelihood of migration pathways (as determined and constrained by the laws of physics and the operational quantities and limitations involved in hydraulic fracturing operations). The second track focuses on contaminant transport following a subsurface migration pathway, and attempts to determine a timeframe for (and flux of) contaminants (liquid or gas phase) moving from a shale gas reservoir to the ground water aquifer.

Acknowledgements

Disclaimer: Information presented in this abstract is part of the US EPA's ongoing study (www.epa.gov/hfstudy). US EPA intends to use this, combined with other information, to inform its assessment of the potential impacts to drinking water resources from hydraulic fracturing. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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Analysis of Feasibility of Extensive Fracture Development and Fault Activation Induced by Hydraulic Fracturing

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Study of Fracture Creation and Propagation During Hydraulic Fracturing Operations

The main focus of this component of our study is the evaluation of the possibility that hydraulic fracturing operations can result in fractures that extend from the shale gas reservoir through the overburden to a shallow aquifer, thus creating a fast permeability pathway that can result in aquifer contamination (Figure 1).

We analyze by means of numerical simulation the propagation of vertical fractures induced by the tensile hydraulic fracturing in shale gas reservoirs. Our study shows that the fracturing mechanism for the shale gas reservoirs is more material strength-dominated, rather than dominated by the viscosity of the fracturing fluids. We first investigate factors that can affect hydraulic fracturing at very early (initial) times, when an instantaneous load is applied to describe the fracturing operation. A high injection pressure and a low tensile strength create more extensive fractures, but we determine that these fractures are finite (stable).

We then investigate fracture propagation during hydraulic fracturing in the case of typical Marcellus shale gas reservoirs. We use rigorous coupled flow-geomechanics modeling, employing an algorithm that describes fully coupled 3D flow, thermal and geomechanical processes, uses the dynamic multiple continuum approach, determines simultaneous tensile and shear failure, and estimates leak-off to the reservoir formation. From the results of the numerical simulation, we find that tensile fracturing occurs discontinuously, thus generating saw-tooth (oscillatory) patterns of responses of the pressure, the fracture aperture, and the displacement (Figure 2). These physical oscillations can be considered as induced micro-seismic events originating from tensile failure.

We also determine that fracture propagation is sensitive to factors such as the initial conditions of (a) the total stress, (b) the pressure and saturation distributions, (c) the type of the injection fluid, (d) the formation property heterogeneity, (e) the formation tensile strength, (f) the elastic moduli of the formation, and (g) the permeability magnitude and models. When the water saturation is large, complex physical responses are observed within the fracture as a result of significant changes in permeability due to fracturing, multi-phase flow of gas and water, and gravity segregation (Figure 3). We find that injection pressurizes both water and gas, inducing further fracturing. Thus, the fracture volume is not the same as the injected fluid volume.

Study of Fault Reactivation and Induced Seismicity During Hydraulic Fracturing of Shale-Gas Reservoirs

The main focus of this component of the study is to investigate the possibility that hydraulic fracturing operations can result in significant reactivation of dormant faults, causing substantial

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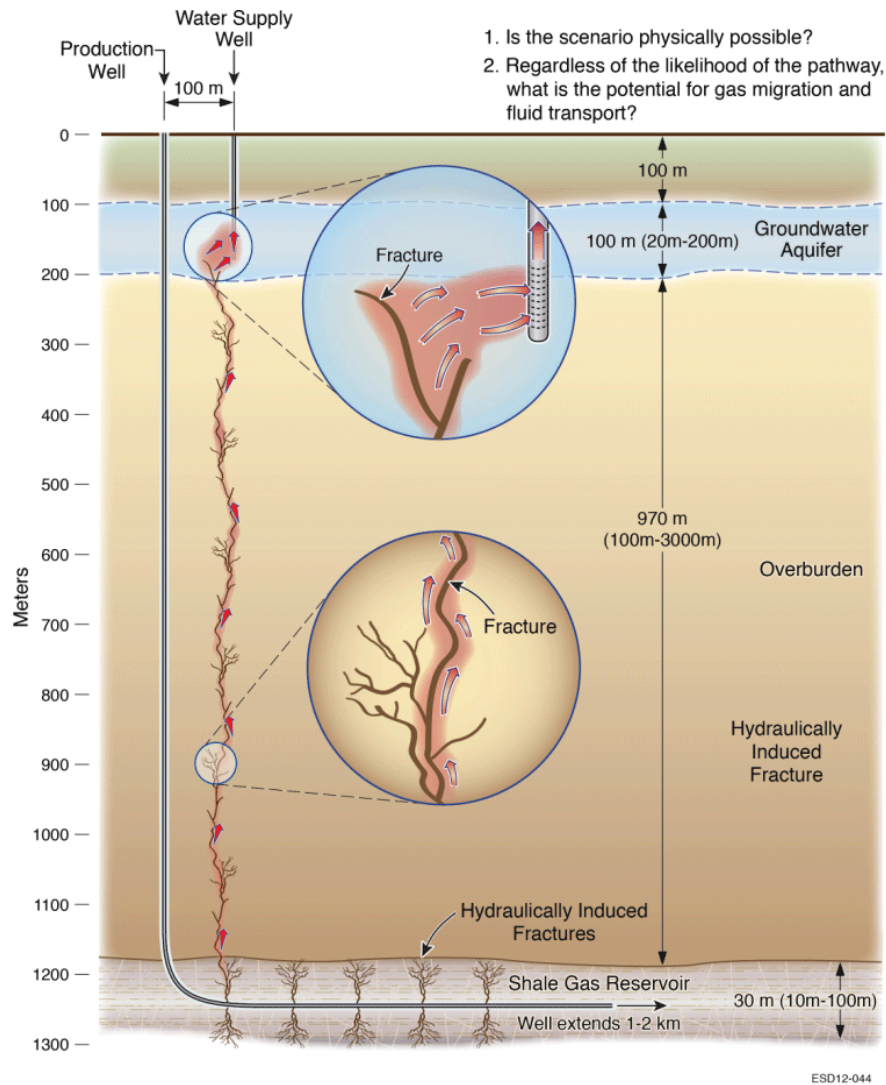June 3, 2013, Subsurface Modeling Technical Follow-up Discussion

displacement and creating pathways for fast transport of contaminants from the shale reservoir to shallow groundwater resources (Figures 4 and 5).

We conducted numerical simulation studies to assess the potential for injection-induced fault reactivation and notable seismic events associated with shale-gas hydraulic fracturing operations. Figure 6 shows an example of such geomechanical behavior under conditions of a constant fluid injection rate. Our modeling simulations investigate whether micro-seismic events are possible and, if so, what is the expected magnitude. Additionally, we estimate important parameters such as rupture along the fault and total displacement (slip).
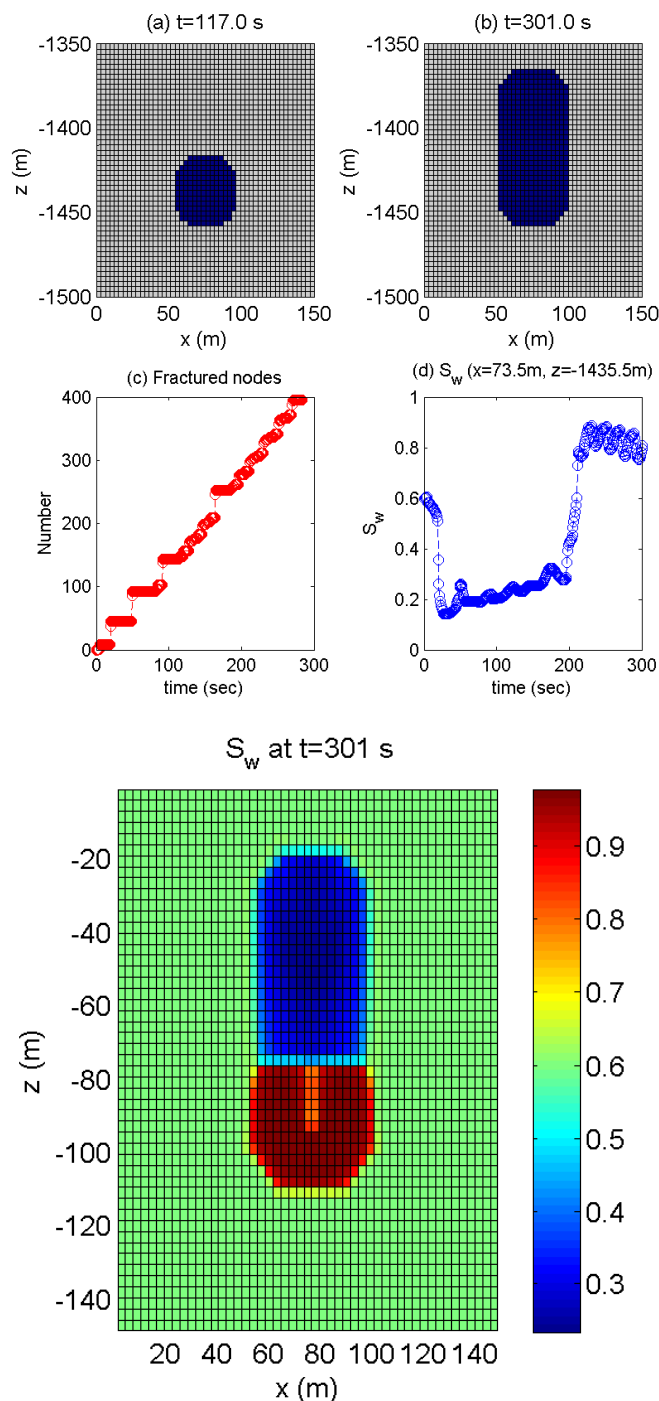
Acknowledgements

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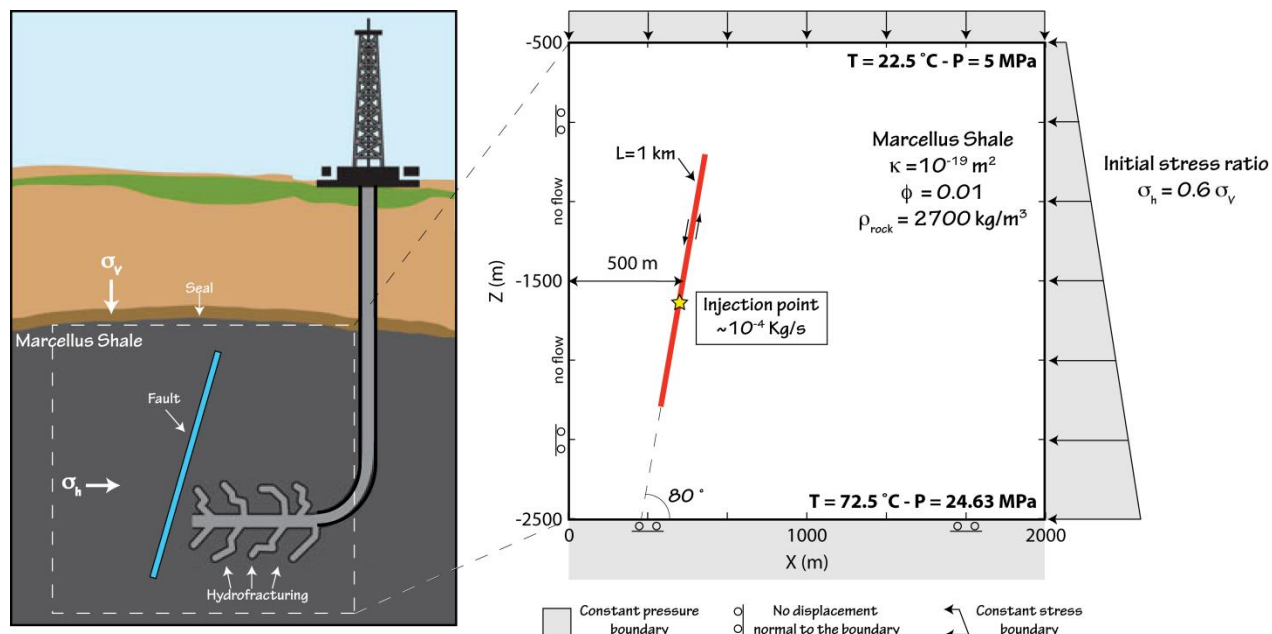
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Figure 1. Considered failure scenario involving fracture evolution from the shale through the overburden to a shallow aquifer.

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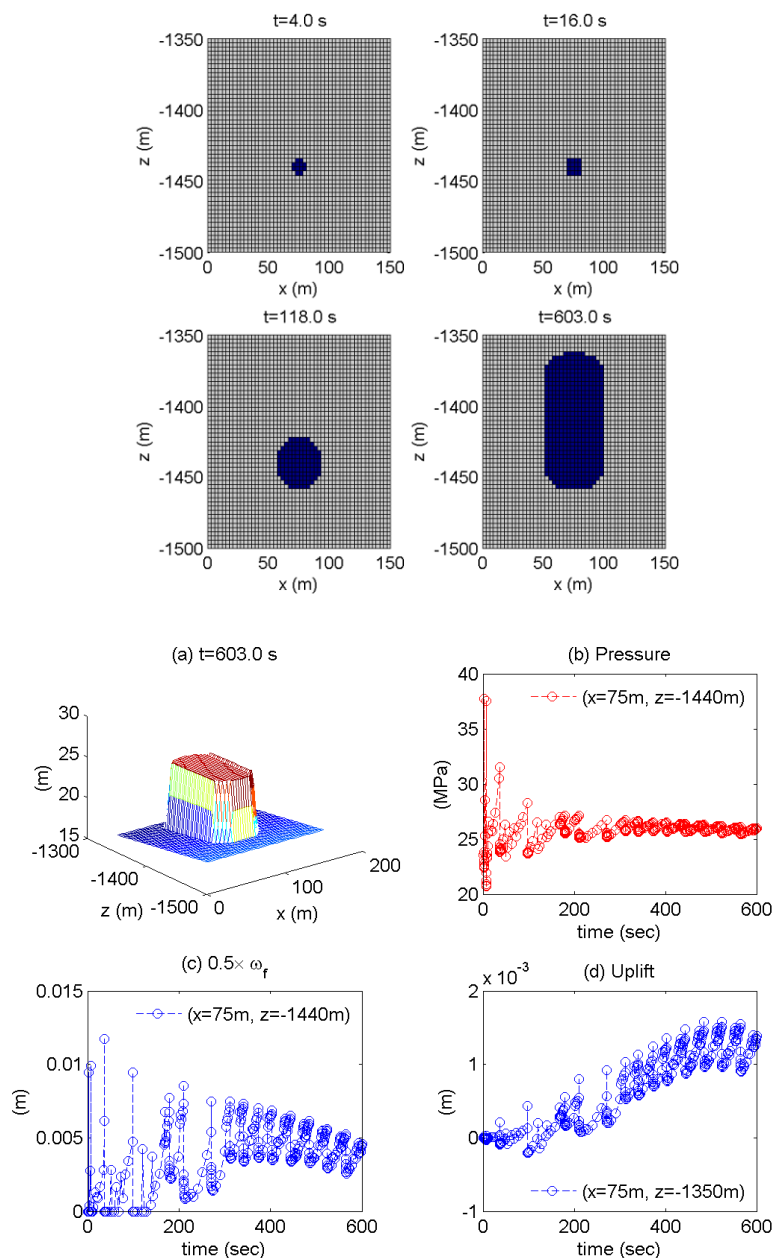
Figure 2. Fluid injection (reference case) when the initial water saturation S_w, = 0.1. Top set: vertical fracture propagation in the x-z plane due to tensile failure. Fracture propagates upward, because the minimum compressive total stress, S_h, is low at the shallow depth, yielding larger fracture openings around the fracture top. Bottom set, clockwise: (a) pressure distribution at t=603s, (b) evolution of pressure at the injection point, (c), variation of the fracture aperture at the injection point, (x=75m, z=-1440m), (d) uplift at the top of the shale layer, (x=75m, z=-1350m). The high-pressure gradient near the fracture tip is due to significant differences in permeability between the fracture and the shale gas reservoir. Saw-tooth pressure (oscillatory) behavior is associated with different time scales between geomechanics and fluid flow. Changes in fracturing status and pressure result in repeated openings and closures of the fractures. The physical oscillation can be considered *microearthquakes* (induced micro-seismic events), generated by tensile failure during the hydraulic fracturing operations.
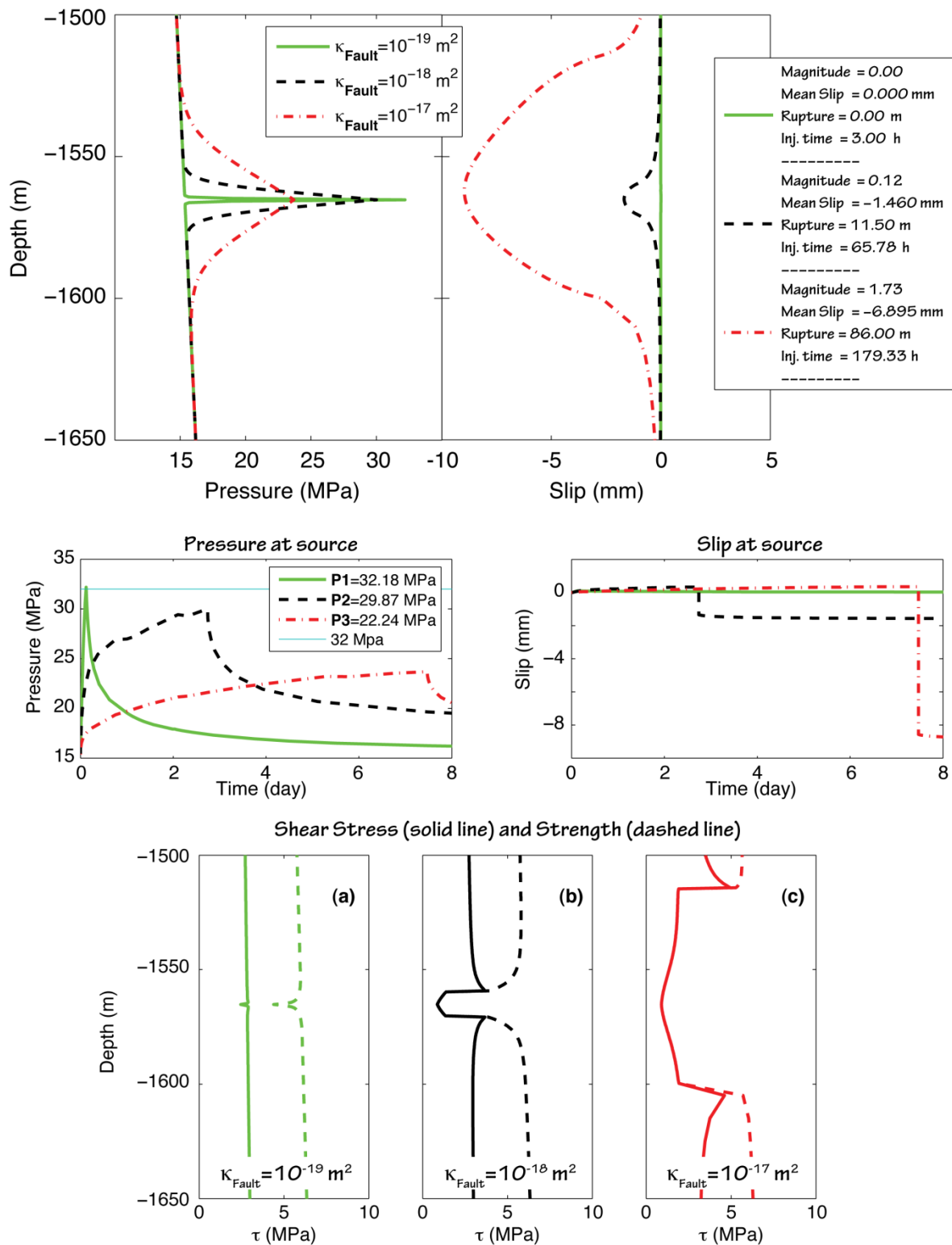
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Figure 3. Fluid injection when initial S_w = 0.6 and the relative permeability is high. Top, clockwise: (a) and (b) fracture propagation, (c) the number of the fractured nodes, (d) evolution of water saturation at (x=73.5m, z=-1435.5m). Bottom: saturation distribution at t=301s. Multiphase flow with gravity segregation and dynamic fracturing causes complex saturation regimes.

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Figure 4. Modeling of reactivation of a minor subvertical fault as a result of nearby shale gas fracturing operation. (a) Schematics and (b) numerical model domain with initial and boundary conditions.
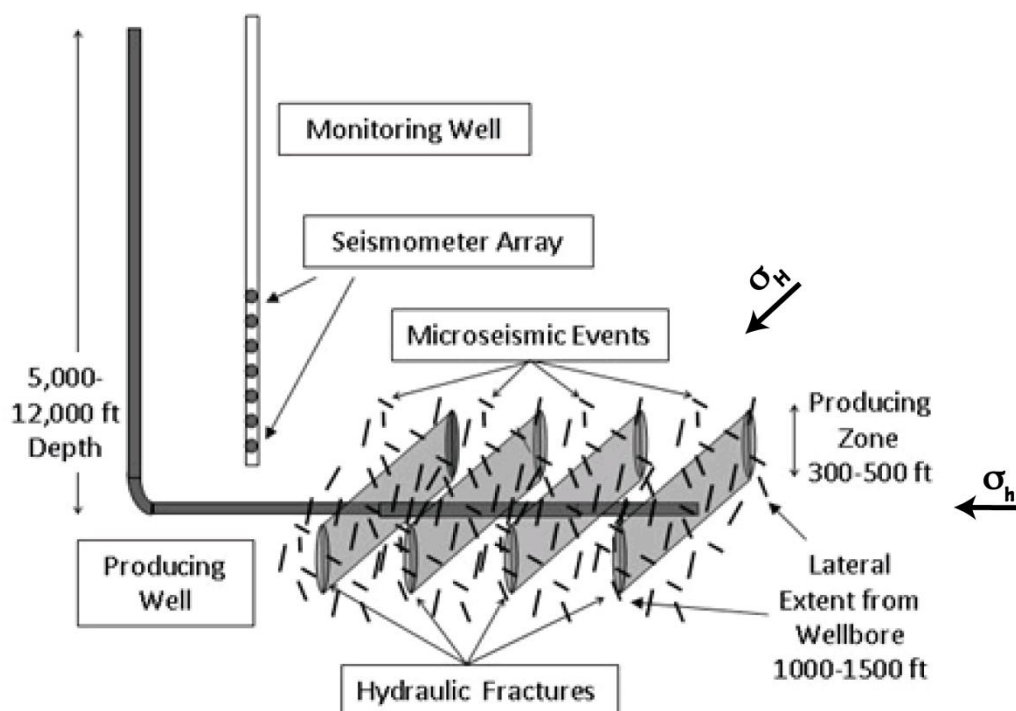
Figure 5. Typical configuration of hydro-fracturing operation along a horizontal well (http://shalegaswiki.com/index.php/Hydraulic_fracturing). In this model we consider one such hydraulic fracture extending up and connecting with a fault.

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Figure 6. An example of simulated induced-induced fault reactivation under constant injection rate with variation of initial (pre-injection) fault permeability.

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Modeling of Leakage in Potential Failure Scenarios for Shale Gas Systems

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The claims made by participants have not been verified or endorsed by EPA.

Introduction

Natural gas from shale reservoirs has become an increasingly important energy resource in recent years. However, the environmental challenges posed by hydraulic fracturing remain poorly characterized. There exist theoretical risks of leakage of contaminants through induced fractures into groundwater resources, but no rigorous model-based analysis has been performed to assess the magnitude of these risks. The mechanisms and quantities of fluids which may realistically be transmitted through induced fractures and faults between geological strata are unknown. Possible exacerbating factors in shale gas well completion or stimulation design are likewise unknown. Quantification of these factors will aid industry in the continuing development of environmentally sustainable hydraulic fracturing practices.

Methodology

The purpose of this study is to determine the rate of migration of gas through a long vertical fracture connecting an underlying gas reservoir upward to an aquifer separated by a significant vertical distance. The aim is to characterize the rate at which the buoyancy of the gas phase drives the gas up through fracture/fault, and to estimate the timescale at which this leakage begins.

TOUGH+RealGasH2O Development
We developed the TOUGH+RealGasH2O code to model the two-phase flow of water and gas in shale gas systems. We have further developed a mesh-building tool capable of capturing the potentially complex geometries involved where thin vertically extensive features intersect multiple geologic strata. We apply these tools toward the modeling of various configurations of the fractured system, using a sensitivity analysis approach based around determining bounding-case scenarios. Parameters of interest include the conductivity of vertically extensive faults and fractures, the relative pressure differential of the underlying shale layer and the aquifer, the permeabilities of the productive intervals, and the vertical distances between layers.

MeshVoro Development
The MeshVoro code was developed with the aim of creating refined grids with the nuance and detail necessary to capture the defined hypothetical failure scenarios. This Voronoi-grid based unstructured meshing tool permits the accurate and efficient creation of complex 3D geometries.

Individual grid objects such as wells and fractures were given a substantial "fade zone" surrounding each object where the grid points are placed progressively less densely stepping further away from the object. As depicted in Figure 1.a and Figure 1.b, the domain at the fringes of the reservoir is gridded relatively coarsely, while the region near the shale well and water well is gridded more densely. Figure 1.a and Figure 1.b both depict an aquifer layer with an embedded water well and an underlying shale layer with a horizontal well, each well possessing

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a precisely refined surrounding. The wells themselves are only a few centimeters in radius and the gridding near the wells is by necessity on the order of 1 cm, while the gridding far away from the wells is in the range of tens of meters.
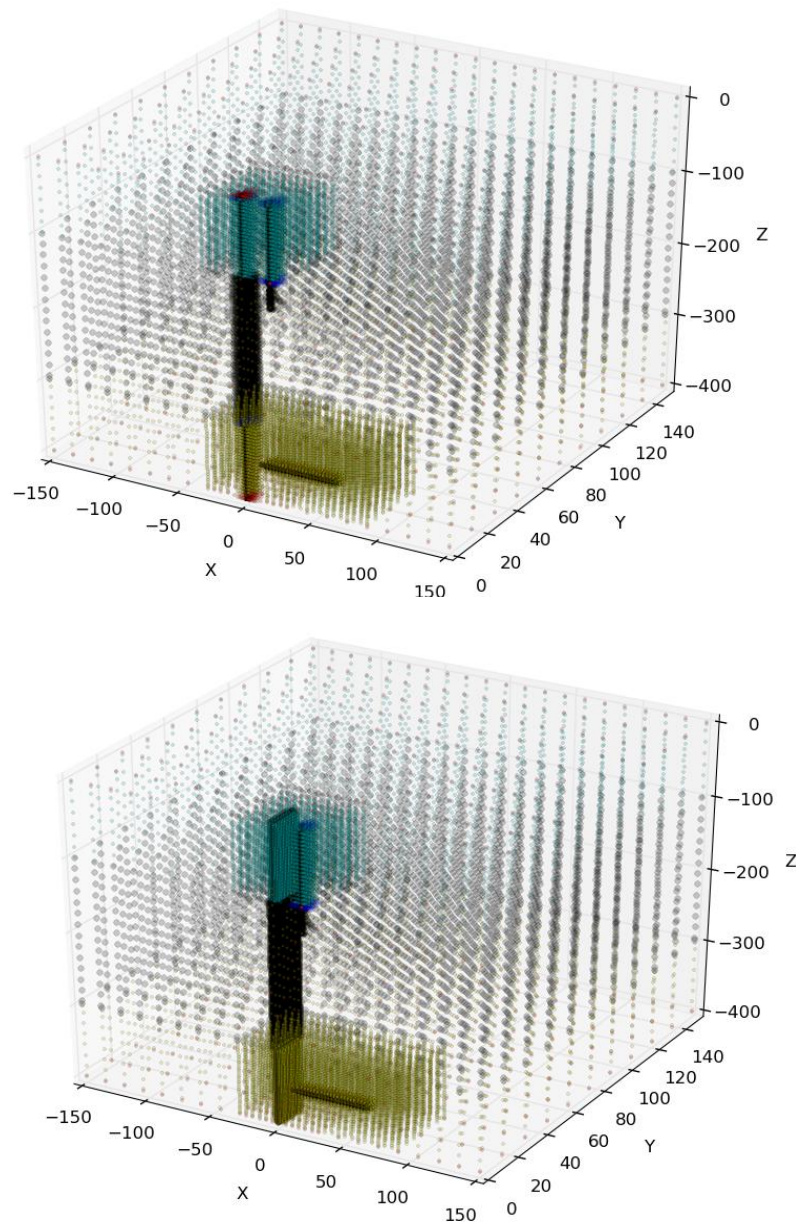
Figure 1. Description of grids used in this study. Top panel: Penetrating older well. Bottom panel : Penetrating hydraulically-induced fracture.

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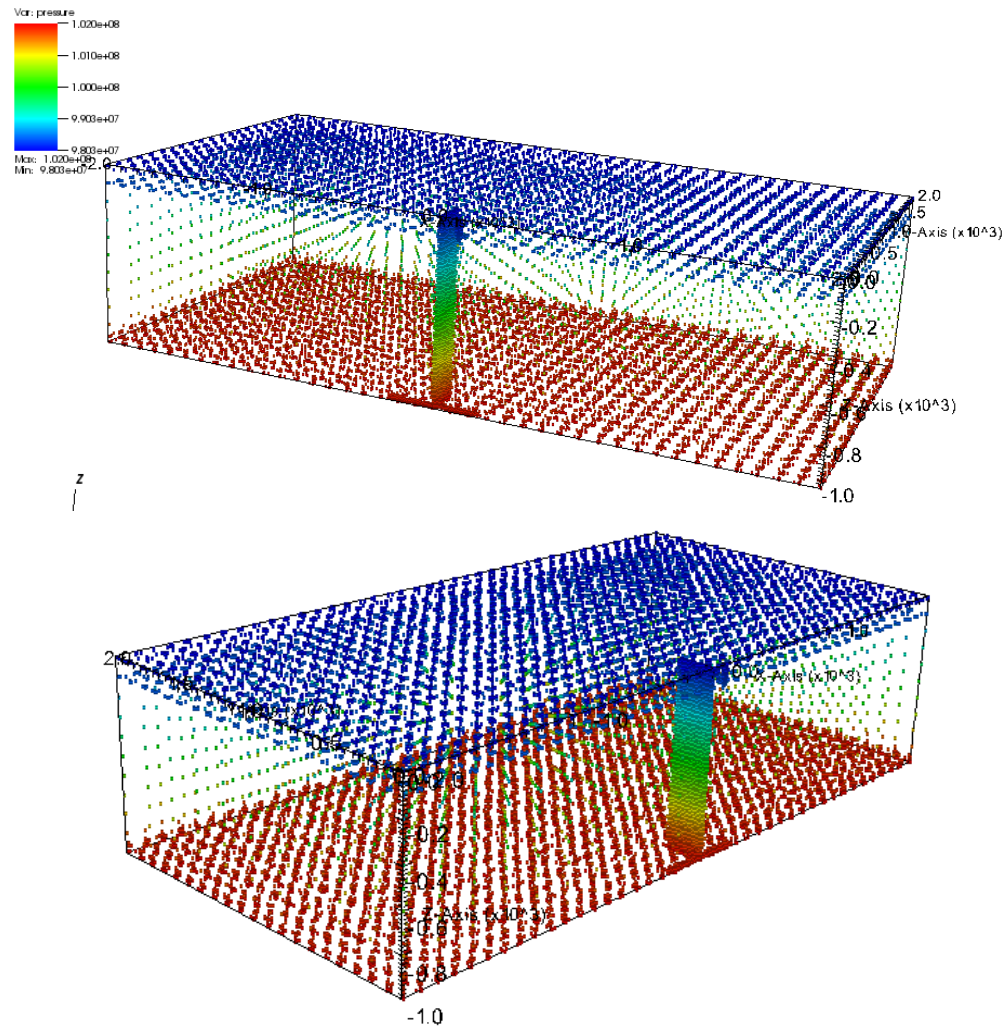
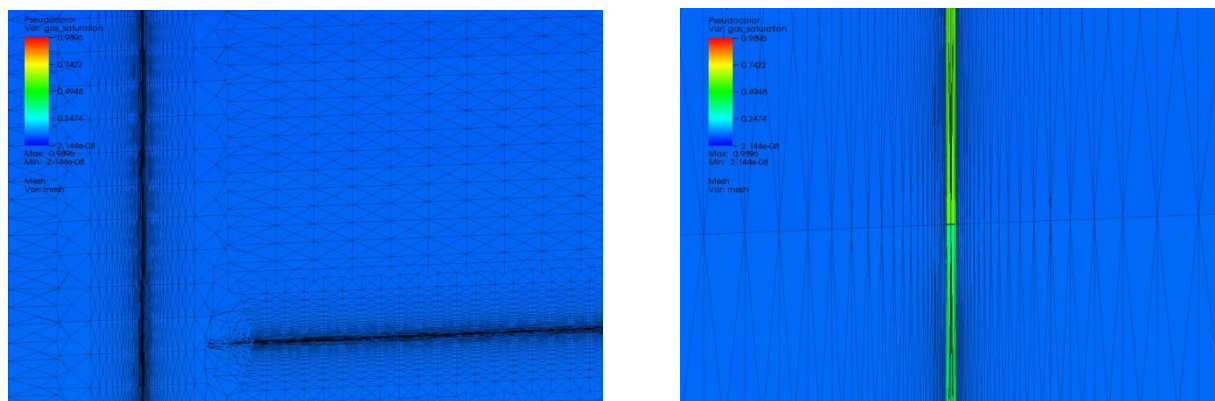**Figure 2. Pressure equilibration. Top: Case 1. Bottom: Case 2.**

Figure 3. Panel a - left: Mesh visualized near well with MESHVoro. Panel b - right: Detail view of gas leaking up well.

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Figure 2.a and Figure 2.b depict the output of a TOUGH+ simulation performing gravitational equilibration of hydrostatic equilibrium within this mesh. The color indicates pressure in Pascal. Note that the pressure distribution is smooth even though the distribution of points is very refined near the grid objects and very coarse near the boundaries. Figure 3.a and Figure 3.b depict the tetrahedralization of the mesh, meaning the actual element volumes are visualized as they exist in the mesh. In Figure 3.b, the rising plume of gas saturation in the wellbore is apparent, colored green.

Results

TOUGH Simulations
A number of TOUGH+ simulations have been performed using a wide range of sensitivity parameters in order to map out the potential behaviors of the gas as it leaks up a well or fracture due to buoyancy or due to a production-driving pressure gradient. At this time, results suggest that the leakage rate is substantially controlled by the conductivity of the leaking flowpath, and by the permeability of the underlying gas reservoir.
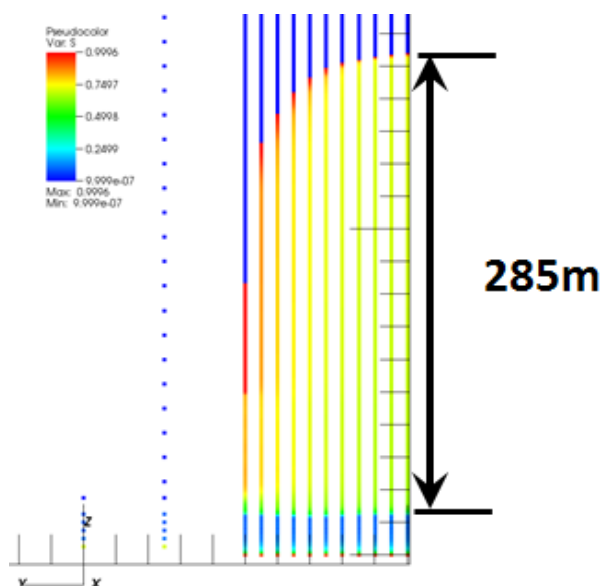
Figure 4: **Gas plume rising up fracture after 255 days.**

Gas Breakthrough Simulations
Each of the systems below is composed of a total thickness of 1000m, with the top 100m aquifer and the bottom 100m shale and the intermediate 800m an impermeable caprock. In the first set, the entire system is penetrated vertically by a well possessing a permeability (given in Table 1). In the second set, the system is penetrated vertically by a fracture possessing a permeability (given in Table 2).

In several of the runs described in Table 1, a well in the aquifer layer located 100m away from the leaking well was producing water at variable rates. Note that Tables 1 and 2 do not describe the entire spectrum of variations in the properties and conditions of the systems we are simulating.

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As expected, an early conclusion that can be drawn from these studies is that the rate of gas flow depends on the permeability of the leaking feature. In addition, the leakage rate is affected by the matrix permeability, the distance between the shale and the aquifer, and the relative pressure regimes in the aquifer and in the shale.

This work may be used to help guide completion and stimulation practices and to identify at-risk areas, such as shale gas reservoirs with closely overlying aquifers. Our simulation tools may also be used to investigate novel leakage scenarios.

Table 1. Some Properties and Conditions Used in the Study of Penetrating Well Systems

k_{shale}	k_{well}	$k_{aquifer}$	Shale Well Production Rate (kg/s)	Water Well Production Rate (gpm)
3.000E-19	3.000E-09	3.000E-14	0.000E+00	0.000E+00
3.000E-19	3.000E-09	3.000E-14	0.000E+00	1.000E-01
3.000E-19	3.000E-09	3.000E-14	0.000E+00	1.000E-03
3.000E-19	3.000E-09	3.000E-14	1.000E-04	0.000E+00
3.000E-19	3.000E-09	3.000E-14	1.000E-03	0.000E+00
3.000E-19	3.000E-09	3.000E-14	1.000E-04	1.000E-01
3.000E-19	3.000E-14	3.000E-14	0.000E+00	0.000E+00
3.000E-18	3.000E-14	3.000E-14	0.000E+00	0.000E+00
3.000E-19	3.000E-13	3.000E-14	0.000E+00	0.000E+00
3.000E-18	3.000E-12	3.000E-14	0.000E+00	0.000E+00

Table 2. Some Properties and Conditions Used in the Study of Penetrating Fracture Systems

k_{shale}	$k_{fracture}$	$k_{aquifer}$
3.000E-18	1.000E-13	3.000E-14
3.000E-19	1.000E-13	3.000E-14

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Emergence of Delamination Fractures around the Casing during Wellbore Stimulation

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Introduction

Casing support and zonal isolation are principal objectives in cementing the wells; however, the latter objective always raises the most concern particularly when there is a potential formation fluid migration into the cement sheath. Wellbore integrity is highly dependent upon the integrity of the interfacial bond between the cement and the formation as well as the bonding between casing and cement. A closer look at the common cement strength test data, performed routinely in the labs, reveal a complicated behavior that cannot be simply modeled using a single parameter i.e. the interfacial strength. Here, we present a more comprehensive constitutive equation to model the behavior of cement interfaces. Comprehensive analysis of micro-annulus formation is presented by utilizing a poroelastic finite element model enriched with interfaces to simulate initiation of the failure zone and possible broaching of the failure zone along the wellbore to shallower zones. Using this model, we demonstrated that it is possible to use data from routine tests to determine not only the shear strength but also normal fracture energy of the cement. The proposed approach provides a tool for a more accurate prediction of cement integrity in subsurface conditions to quantify the risk of wellbore integrity issues.

Cement Sheath Integrity

Cement is used to support the casing and also provide hydraulic isolation of various formations penetrated by the wellbore, accordingly preventing fluid flow from high-pressure zone to low pressure zones. Cement also protects casing from corrosion by chemically aggressive brines. The quality and integrity of a cement job can determine how long a well remains stable and productive without requiring repair. The cement sheath failures and nearby wellbore failures may lead to upward flow of formation fluid, which has significant adverse consequences on wellbore integrity (Figure 1). Field and laboratory experiments have revealed two types of mechanisms responsible for the loss of cement sheath integrity: mechanical degradation (Goodwin and Crook, 1992) and chemical degradation (Kutchko et al., 2007). For instance, wet or dissolved CO_2 form a corrosive fluid can induce chemical degradation in cements. Degradation-kinetics data show that chemical degradation is controlled by fluid diffusion rate, so it may not be very fast unless leakage pathways already exist due to mechanical degradation (van der Kuip et al. 2011). As a consequence, it is crucial to understand mechanisms lead to mechanical degradation beforechemical degradation occurs (Bois et al. 2012). In this paper, we mainly focused on mechanical degradation mechanisms.

Nowadays, environmental protection is of greater concern than ever, especially the protection of shallow aquifers during and after drilling and completion. Therefore, understanding the formation of liquid movement paths has become an important step to achieve long-term mechanical durability of a cement sheath exposed to different conditions during the well life. It is

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notable that liquid movement does not usually occur around the wellbore uniformly. Due to the inherent heterogeneity of rock and cement, fluid flow around the casing tend to limit itself to a number of routes, which leads to a higher fluid flow velocity and consequently larger fluid drag forces on cement particles. Larger drag forces may move cement and rock particles easier and provide a preferential path for fluid to flow. These paths, also known as channels, may further fracture the rock to form small cracks. The integrity of the cement sheath could be undermined as a result of these annular cracks development (Goodwin and Crook, 1992). The creation and the deteriorating impact of these fractures are controlled by several factors governed from cement composition, the cement curing process, thermal stresses, hydraulic stress, compaction, wellbore tubular, and downhole environment (Jutten et al. 1989, Berger et al. 2004).
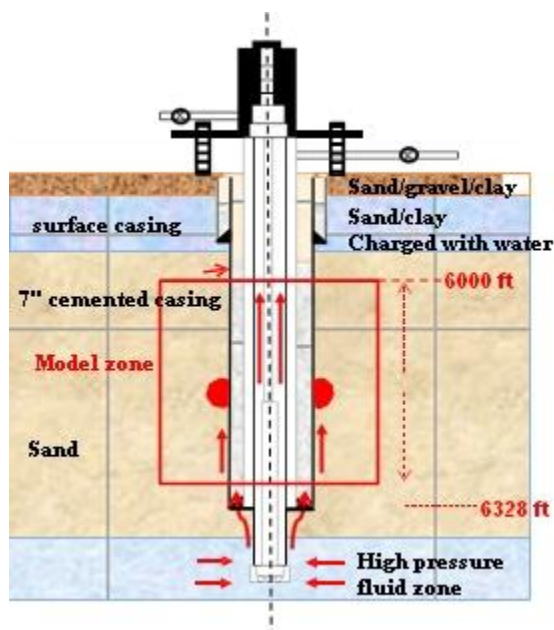
Figure 1. Upward flow migration could be due to leakage at the casing shoe because of excessive pressure during hydraulic fracturing or excessive pressure at the perforation at the fracturing depth.

Development of new measurement technologies, such as CBM, ULT (Boyd, et al, 2006 and Jiang, et al, 2012) on one hand and more sophisticated constitutive models to predict the behavior of different materials interfaces on the other hand, provide more opportunities to apply more sophisticated model to gain deeper understanding of the physics behind fluid migration behind the casing. In this paper, initiation of the failure zone is modeled using an axisymmetric poroelastic finite element model, which is enriched with cohesive interfaces to model cement interfaces.

Theory of cohesive interfaces

The criteria for fracture propagation are based on the energy release rate approach, which states that a fracture propagates when the stress intensity factor at the tip exceed rock toughness. For inherent nonlinear nature of interfacial cracks, the most robust criterion is described by the constitutive model of the cohesive zone (Barenblatt 1962; Hilerborg et al. 1976). In the cohesive crack approach, the fracture processing zone is modeled by a cohesive crack of zero width with

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traction transferring capacity. The energy dissipation with the fracture processing zone is taken into account through the traction crack opening displacement constitutive model (Xie, et al. 1995). Cohesive interface starts to open when the tractions applied to the interface reach a critical point, which is described by traction separation law (Tvergaard and Hutchinson, 1996). Traction separation law is the basic theory for the description of damage initiation and its propagation. One of the advantages of this criterion over similar ones is its flexibility to tune the parameters to incorporate the behavior of different fracture mechanisms. For instance, different materials show different bridging properties across the fracture tips, which could be quantified from lab measurements.

Carter and Evans (1964) presented an experimental setup to measure shear bond and hydraulic bond. What they measured as the hydraulic bond is a mixed mode of shear and tensile cohesive energy. We utilized a process for using finite element method to determine cohesive stiffness, strength and energy properties out of these tests. Properties are calibrated such that simulated tests match the measured response of the specimens. Using pure mode test data to characterize cohesive behavior minimizes the number of cohesive properties that must be simultaneously determined. Fortunately, shear bond test is in pure shear mode for the large extent of deformations, but unfortunately, no such test has been developed to measure cement interface properties in pure normal mode. Evan and Carter (1962) proposed the pull-out test as a way to measure the shear bonding strength between cement and formation. A schematic picture of push-out tester is demonstrated in Figure 2. The center shale plug has a diameter of 25.4 mm and a nominal length of 20 mm. The shale core is being dragged slowly by a brass rod with a diameter of 20mm where the cell surrounding cement ring is constrained against any movement. A typical force versus displacement plot for this test is provided in this paper, which is considered as the benchmark for our numerical tests.
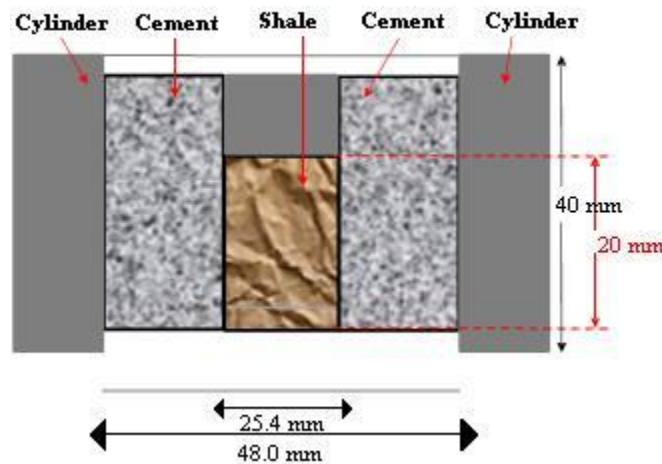
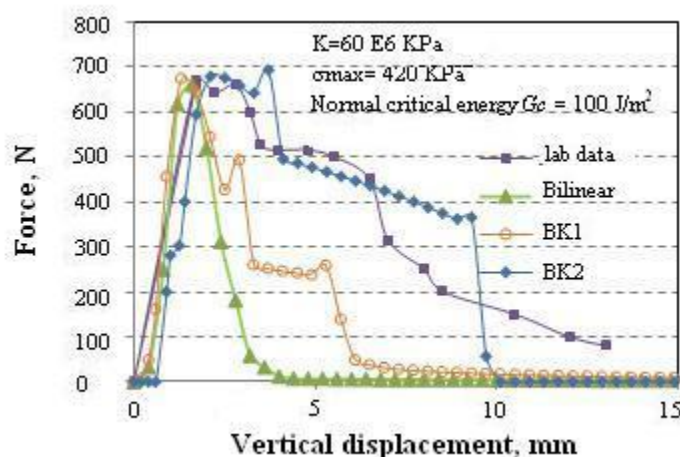**Figure 2**. **A schematic of the push-out tester.**

In an attempt to characterize the failure damage mechanism between cement and formation, numerical simulation was performed to estimate shear strength (peak and residual), and deformability (shear stiffness) of the interface. An axisymmetric finite element model is built in

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ABAQUS for this objective. In the process of pulling out, shear displacement was imposed by applying a constant velocity, v = 0.002 m/s, to the top part of the rock sample. The shear force applied to generate the constant velocity to the shale was monitored via a shear displacement relative to the cement. Confining pressure (normal stress) might be added at the outside of cement to simulate downhole condition. We assumed that delamination propagation initiates from an all-around cylindrical flaw. Hence, an axisymmetric finite element model, which is a slice of the three dimensional geometry, can be used for stress analysis (shown in Figure 3). This model is meshed using commercial and in-house mesh generators. The model consists of casing, cement sheath and a permeable elastic surrounding rock.
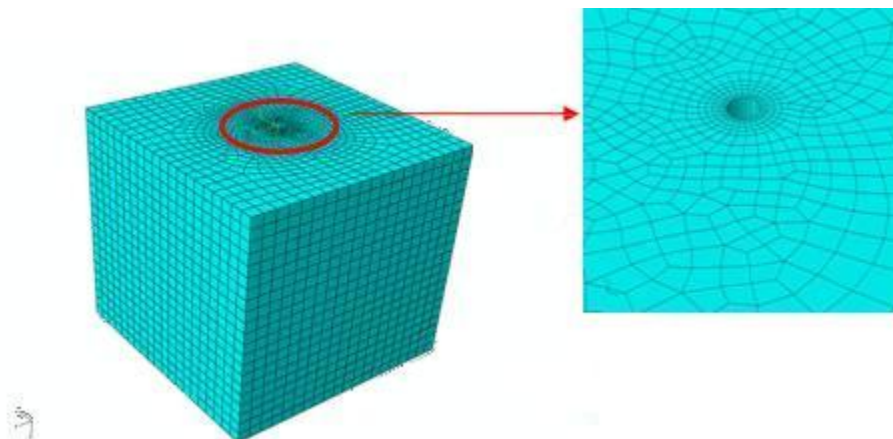
Figure 3. Schematic picture for three dimensional poroelastic finite element model.

The sheer force vs. cement shear displacement is shown in Figure 4. Two utilized failure initiation criteria show identical linear behavior at the initial stage of loading due to elastic deformation. The peak strength occurred at shear displacement around 2 mm, which is about 10% of the specimen's length. The observed sharp peak strength demonstrates an effective locking of the cement to the rock. Initial linear elastic response produced using bilinear and BK both agree with the experimental results. Then peak strength is followed by a sharp softening process in bilinear form, whereas, the peak stress-softening in BK form is followed by another two peaks and sharp softening processes, which is probably due to the change in loading mechanism from shear to tension cause by large deformations. The softening comes to the play after reaching the peak strength. In the calibrated results produced by BK criterion, two softening stages are observed after reaching peak strength. The first soften strength is larger than the second one. The second softening and stabilization process is significantly wider than the first one. Further numerical investigation showed that second softening process is governed by cement-casing interface, rather than shale cement interfaces. Cohesive parameters calculated from lab experiment can be used for field scale simulation of cement integrity problems. Currently, the cement strength is the only parameter used for integrity analysis of the cement sheaths in the fields, but we can see that other parameters should be included to have a realistic model of what might happen in the real world.

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Figure 4. Comparison shear force with cement shear displacement in models with different traction separation law.

Conclusion

Protection of shallow aquifers is an increasing concern, so regulatory requirements for cement performance in well abandonments, drilling and hydraulic fracturing should improve; however at the same time more sophisticated techniques are required for assessment and simulation of long-term integrity in the oil and gas wells. Advent of new ultra sonic technology which gives azimuthal measurements provides a reliable assessment tool but these tools have no predictive capability. Additionally, appearance of new cement additives in the market requires more sophisticated techniques to predict cement integrity under severe conditions in the surface based on the common lab test data. To address these needs, more sophisticated models are required to predict mechanical behavior of cement interfaces. Here, we used cohesive interface constitutive equation to describe mechanical characteristics of cement interface during failure. Potential delamination paths can be predefined by cohesive elements without any presumption of the initial crack size or location. The main challenge in using cohesive model is choosing, or being more accurate, measuring cohesive model parameters in the lab. A process for using finite element method to arrive at cohesive stiffness, strength and energy properties explained in this paper. Properties are calibrated such that simulated tests match the measured response of the specimens. Then the cohesive element approach provides a tool to evaluate this process in the wellbore scale. Moreover, the proposed approach can predict the wellbore integrity influenced by imperfect cement, excessive pore pressure near the wellbore, which provides an important insight on the role of cement mechanical integrity on wellbore isolation.

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Abandoned Wells as a Potential Leakage Pathway:
Lessons Learned from CO₂ Geological Storage

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Princeton University

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Leakage along wellbores is recognized as one of the potential risks associated with Geological Carbon Storage. This is especially true in North America, where there are millions of abandoned wells, many of which are co-located with potential CO_2 storage formations. Large-scale injection of CO_2 into deep saline aquifers can lead to leakage of the injected CO_2, the displaced brine, or both. A variety of simulation tools have been developed to estimate potential leakage along existing wells, associated with injection of CO_2 and subsequent migration of both CO_2 and brine. The modeling approaches have been designed specifically to simulate large-scale CO_2 injection problems. While there are important differences between large-scale CO_2 storage operations and production of unconventional oil and gas, the leakage pathways are similar and both systems involve two-phase fluid flows. Therefore, it may be beneficial to consider how studies of potential CO_2 leakage might inform the study of potential leakage of fluids associated with unconventional oil and gas production.

High uncertainties associated with the hydraulic characteristics of abandoned wells require Monte Carlo calculations, which in turn necessitate development of efficient (simplified) modeling approaches. We have developed a series of simplified models, ranging from reduced-spatial-dimension numerical simulators to analytical and semi-analytical solutions. These allow us to analyze problems like the one illustrated in Figure 1, where a lateral spatial domain of 50 km by 50 km is simulated. Flow is driven by an assumed injection in the center of the domain using a single vertical well. The domain includes more than 1,200 existing wells, which are shown in the figure. The model involves 8 layers in the vertical. We assume each formation has a single value of permeability, so that each formation is spatially homogeneous. We similarly assume the resident brine and the injected CO_2 have constant fluid properties, we ignore mass transfer between the two phases, we assume the fluids are instantaneously segregated by buoyancy and that they are separated by a macroscopic sharp interface. With these major assumptions, we can derive analytical and semi-analytical solutions that include multiple formations (layers) in the vertical direction and represent all wells explicitly.

The major randomness in the system is associated with the assignment of effective permeability values along the 1,200 potentially leaky wells. Different options can be chosen for the probability distributions that represent the leaky well permeabilities – for details see Celia et al. (2011) or Court (2011). One simple choice is a bi-modal lognormal distribution, with one mode corresponding to "good" or "intact" well cement outside of casing and the second mode corresponding to "bad" or "degraded" cement sections.
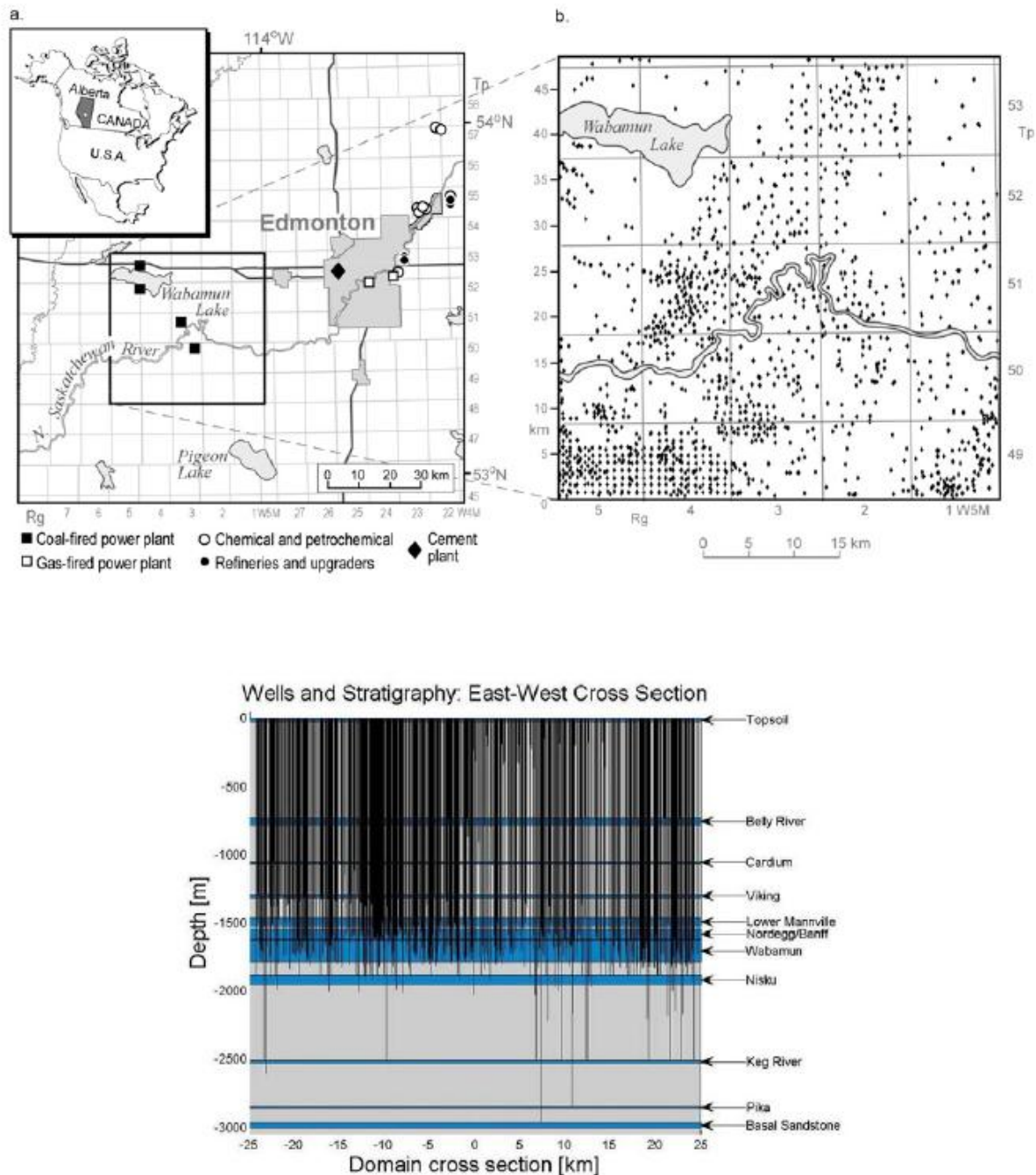
A typical example result is shown in Figure 2, corresponding to 50 years of injection into the Nisku formation (fourth lowest aquifer in Figure 1). One thousand realizations were run, each with different values of well permeability assigned to the potentially leaky wells, with values drawn from the bi-modal lognormal distribution. Two histograms of leakage values are shown in

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Figure 2, with leakage computed as the fraction of the total injected CO_2 that leaks out of the injection formation after 50 years of injection. One histogram is based on having one single permeability value applied along the entire length of a given leaky well ("correlated" results), while the second assumes a different value is assigned for each well segment that crosses an aquitard or caprock formation (the "uncorrelated" results). Details can be found in Celia et al. (2011) or Nogues et al. (2012).
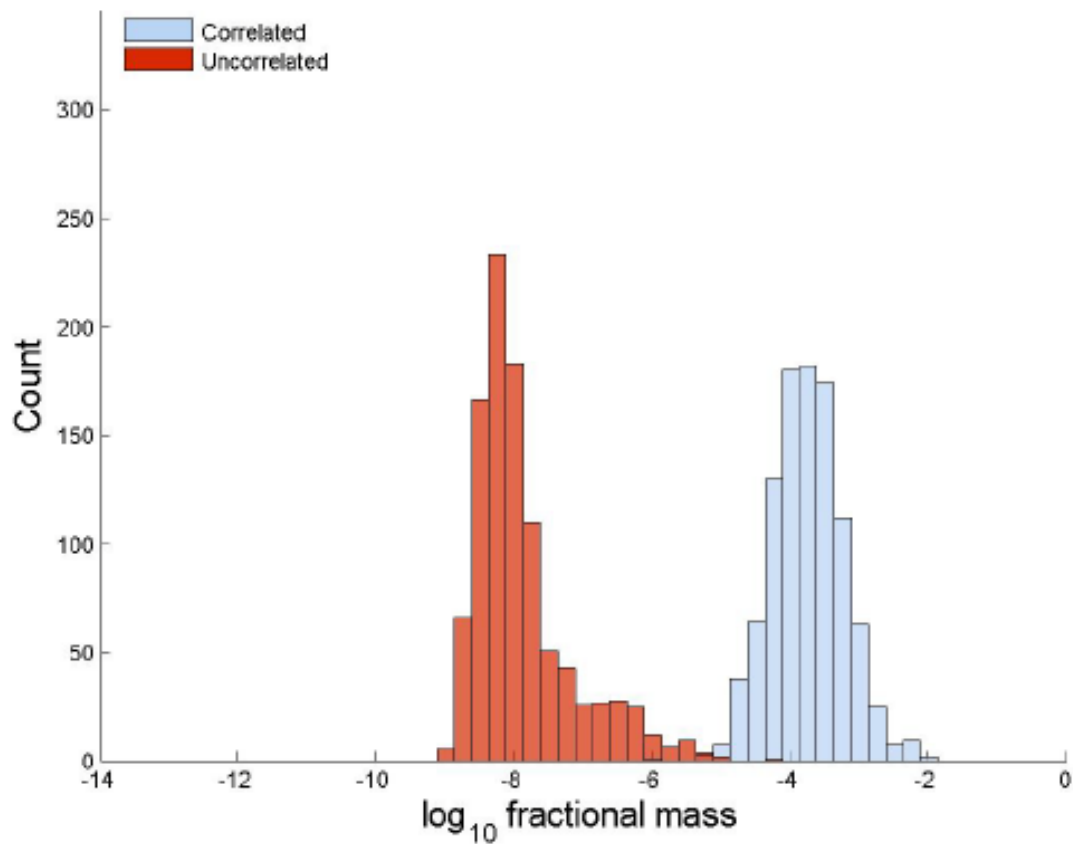
We have used these kinds of models to explore the parameter space for the major input parameter, which is the distribution of values of well permeabilities (see Nogues et al., 2012). We have concurrently worked with collaborators at BP and Schlumberger to enter old wells and perform tests from which actual permeability of cement (and other materials) outside of casing can be estimated. The procedures are described in Gasda et al. (2008) and Crow et al. (2010). While to date we have only a few data points, the combination of field measurements and simulation results appear to indicate acceptably low leakage rates for both CO_2 and brine.

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Figure 1: Location of study site in Alberta, showing location (a), location of the approximately 1,250 existing wells (b), and depth of penetration of the wells (c). Figure taken from Celia et al. (2011).

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Figure 2: Fraction of injected CO₂ that leaks into shallow subsurface zone after 50 years of injection. Figure from Celia et al. (2011).

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Appendix D.

Poster Abstracts

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Well Design and Construction in Texas

Travis N. Baer

Railroad Commission of Texas

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Introduction

An oil and gas operator is responsible for maintaining compliance with all state and federal regulations during all operations at the well, including reservoir stimulation by hydraulic fracturing. It is the intent of the regulations set forth by the Railroad Commission of Texas (RRC) that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones, over-pressured zones or zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When a regulation does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the regulations, using good engineering practices and the best currently available technology.

The RRC has set forth rules and parameters since 1919 that all operators operating in Texas must follow to ensure integrity of the well and protection of freshwater resources. The RRC has also recently proposed new rules outlining best management practices already utilized in the field and some new requirements already utilized by the industry to better protect freshwater resources and the general public as drilling and completion technology has advanced. *Please note that while most of the information presented below reflects current RRC rules as they pertain to well construction requirements, some of the requirements (such as minimum cement sheath thickness, isolation of corrosive and over-pressured zones) are presently proposed as changes to statewide rules and thus subject to change.*

The following is a relatively brief description of minimum requirements established in current and proposed RRC rules to ensure wellbore integrity and protection of freshwater resources. These requirements have long been established in Texas and are expected to mitigate some of the concerns for potential migration of hydraulic fracturing fluids addressed in the EPA's Subsurface Migration Scenario Modeling efforts.

Surface Casing

Setting the first string of casing to isolate all the freshwater bearing aquifers and ensuring cement is circulated from the casing shoe to ground surface is crucial. The depth of the surface casing must be such that it isolates the fresh water and usable quality water aquifers from deeper formations and is typically determined by the Base of Usable Quality Water (BUQW) protection depth, or the depth of the bottom of the deepest freshwater aquifer, as determined by State of Texas licensed Geologists working for the Railroad Commission of Texas. The proper identification of these fresh water zones (<1,000 mg/L Total Dissolved Solids (TDS)) and usable quality water zones (<3,000 mg/L TDS) by licensed geologists in the regulating body is crucial in ensuring the water resources are protected and helps alleviate ambiguity if operators were to determine their own

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protection depth. Regulating entities should also consider including the Underground Sources of Drinking Water (USDW; <10,000 mg/L TDS) depths as part of the protection depth. When drilling the surface casing hole, operators must utilize freshwater mud of sufficient weight to maintain control of the well at all times.

In Texas, operators are required to set surface casing to at least the BUQW, but no more than 200 feet deeper than the BUQW. However, in many instances, it may be beneficial to set surface casing either shallower, or significantly deeper (>200 feet) than the BUQW due to the geology and location of the fresh water sands in the well. In some cases, fresh water can be as deep as 6,000 feet or more below ground surface. Going this deep with only one string of casing can be risky considering blowout preventers and other well control equipment cannot be installed until after surface casing is set and increased mud weight for those depths may be greater than the fracture pressure in shallower fresh water formations. It is recommended that in any instance where the surface casing may be set deeper than 3,500 feet that the regulating entity evaluate each wellbore and well control design on a case-by-case basis. Operators should utilize multi-stage cementing tools in the casing design when setting deep surface casing or when using intermediate casing to isolate some usable quality water formations.

The surface casing acts as a barrier between the aquifers and deeper formation fluids during drilling and completion of deeper casing strings, and also acts as a redundant barrier between the migrating fluids in the production tubing/casing and the freshwater aquifers. The hole in which the casing is to be set should be of sufficient diameter (proposed to be at least 1.5 inches greater than the diameter of the casing) to accommodate for a sufficient cement sheath outside the casing. The casing should also be properly centralized in the wellbore to prevent cement channeling where casing may be too close to the wellbore wall. The quality of cement for the bottom section of the surface casing must be of superior quality to ensure the casing is adequately anchored and will not allow for migration of fluids in the casing annulus. Minimum parameters for this high-quality cement are strict enough to ensure good anchoring and pressure resistance, yet amenable enough to allow operators and service companies to design new cement slurries with different properties to accommodate the different geologic formations encountered in the wellbore. Cement slurries must meet equivalent specifications listed in American Petroleum Institute (API) standards. Operators must accommodate for wellbore washouts and irregularities by pumping excess cement, typically no less than 30% excess, to ensure cement circulates to surface. However, if the operator is not able to circulate cement to the surface, the operator must remediate the cement job either by "topping off" with cement from the top down through the annulus, or perforate at the measured top of cement and squeeze cement through the annulus to the surface. The regulating entity should be actively involved in evaluating any surface casing remediation job on a case-by-case basis to ensure proper protection of the groundwater resources. After waiting on cement and prior to drilling out through the bottom of the casing shoe, the casing must be pressure tested to ensure the casing does not have any defects and that the freshwater zones are properly isolated. A formation integrity test (FIT) should also be performed soon after drillout to ensure the casing shoe is properly cemented (this process is known as a casing shoe test).

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Well Control Equipment at the Surface

The surface casing provides an anchor for the well while also providing an anchor for well-control equipment, including blowout preventers, to be installed onto the well. While there can be many variations in well control equipment, everything from blowout preventers and their individual rams, to diverter systems, to gas separation equipment, to mud conditioning equipment must be designed to accommodate for expected conditions at each well. Surface equipment should be designed and tested to withstand the maximum allowable surface pressure (MASP) that may be imposed during a hydraulic fracture treatment or during any other event in the life of the well. All equipment should be tested according to manufacturers' and API specifications, and also include factors of safety to ensure that continued use will not cause a mechanical failure and potential impact to freshwater resources and the general public. In harsh environments such as sour gas or corrosive production, special metallurgy or steel coating should be utilized to protect the well control equipment during prolonged use in accordance with API specifications.

Intermediate and Production Casing

After surface casing has been set and cemented, and all well control equipment installed, the design of the well may vary according to operator preference, geologic conditions, or reservoirs characteristics, but minimum parameters must still be met by all operators to ensure isolation of the oil and gas bearing formations and prevent migration to shallower formations through the casing annulus. Each string of casing set must be able to withstand the expected reservoir and/or applied hydraulic pressure that the well is expected to undergo. It is preferred that each string of casing have cement circulated in the annulus from shoe to surface. However, due to the depths and geophysical properties of some formations, it is not feasible to circulate cement from shoe to surface. Therefore, the operator is required to cement each string of casing at least 600 feet above the shoe or 600 feet above the shallowest oil or gas productive zone, whichever is shallower. Cement should also be circulated above depths of known over-pressured or corrosive zones and zones to which fluid is injected into for disposal operations. Operators may set an intermediate string of casing to accommodate for these types of formations. It is recommended cement be circulated to at least 200 feet above the surface casing shoe to provide optimum isolation of formations. The volume of cement pumped through the casing shoe must be enough to isolate all productive formations based on the drilled-hole size and the outside diameter of the casing, including a "washout factor" of up to 30% excess to account for drilled-hole geometry irregularities. If it is determined that less than 600 vertical feet of cement has not been pumped through the casing annulus, a temperature survey or cement bond log must be run to determine cement height and/or bond integrity. There should be no less than 250 feet of cement slurry height as determined by a temperature survey or 100 feet of well-bonded cement as determined by a radial cement bond evaluation tool (see Fig. 1). The drilled-hole diameter should be no less than 1-inch larger than the outer diameter of the casing in order to allow proper use of cement bond evaluation tools as cement bond evaluation tools can accurately evaluate cement bond in no less than a 0.5-inch cement sheath. In horizontal or deviated wells, additional centralization must be utilized to allow for adequate radial circulation of cement around the casing and prevent channeling.

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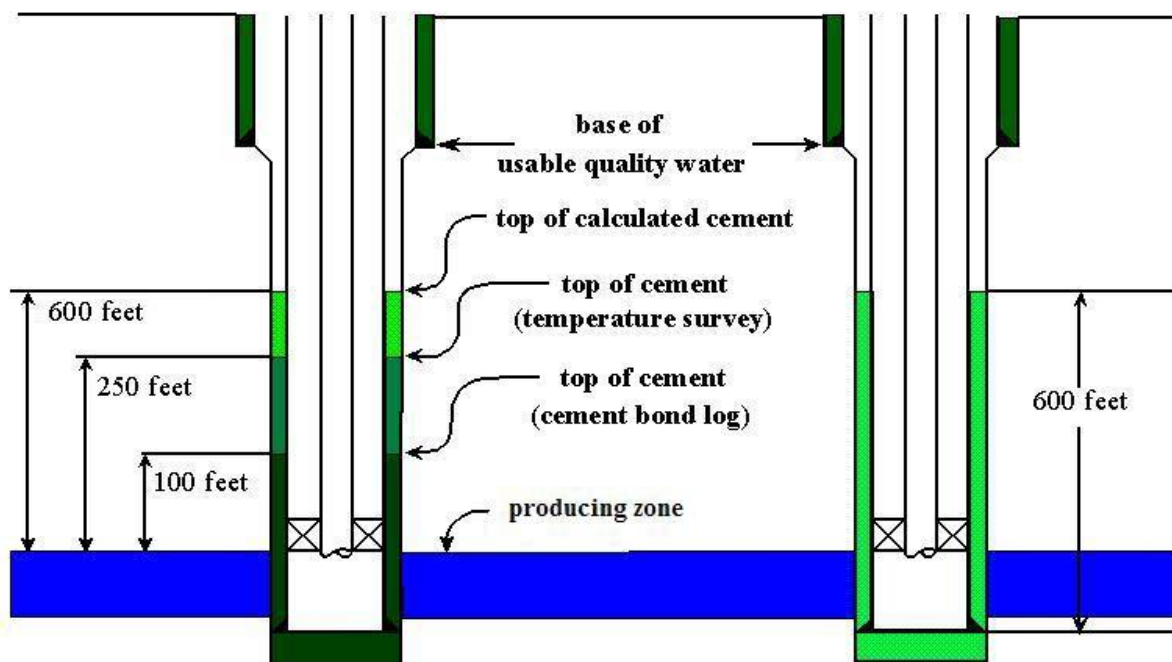June 3, 2013, Subsurface Modeling Technical Follow-up Discussion

Figure 1. Criteria for Determining Adequacy of Cement

Hydraulic Fracturing Operations

The cementing of the production casing is essential in the isolation of the oil and gas bearing formations during both completion and fracture stimulation operations and through the life of the well. The casing and cement must be designed to withstand high pressures and temperatures and have enough elasticity to withstand the pressure variations during hydraulic fracturing operations and reservoir depletion over the life of the well. Before the production casing is perforated in the pay zone and after the cement has had sufficient time to set up, the production casing should be pressure tested to the maximum pressure that will be applied during hydraulic fracturing operations. This pressure test is key in ensuring the casing is free of defects. If using "frac plugs" as treatment stage isolation, each frac plug should be pressure tested after setting and before perforating to ensure that the plug holds and that the casing has not mechanically failed during prior treatment stages. During hydraulic fracturing operations, it is imperative to monitor all well casing annuli for any pressure fluctuations that may indicate a possible casing leak or cementing problem. If any pressure fluctuation out of the ordinary is detected, fracturing operations must cease immediately and the source of the problem identified and remedied. All pressure tests performed on the wells must be well documented and reported to the proper regulating authorities.

Operators should also take into consideration other wells near proposed facture-treated wells.

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There have been several documented cases of in-situ communication across wellbores which can cause nearby wells to overflow their production tanks due to the substantial increase in flow rate. In some cases, the fracture treatment caused a nearby well to blow through an unclosed valve or a bull plug. In these documented cases, there was always a surface spill of produced fluids. However, in none of the cases was it determined that there was a well integrity problem and there was no recorded instance of groundwater contamination. These situations can be avoided with proper notification of fracture treatment to offset operators and research of adjacent or nearby wells to ensure all other wells are properly constructed to prevent well integrity issues.

Exceptions and Additions

As with all rules of the nature of engineering design attempting to encompass a broad range of design characteristics, room for exceptions should be allowed to accommodate for irregularities and new technologies without having to go through the strenuous process of rulemaking. Exceptions must be evaluated on a case by case basis by professionals in the regulating body to ensure protection of freshwater resources and the general public. Regulations should also allow for the regulating body to make more stringent well design changes on a case-by-case basis in sensitive situations or locations.

Conclusion

It is impractical to set specific parameters for each well drilled by every operator due to the diversity of the geology and technology available. However, there are minimum standards that can and must be met for each well to ensure the protection of groundwater resources and the general public. It is up to the regulating agencies to provide structure and guidance for these standards, but to also allow for changes as needed to allow for special conditions or technological advances that may offer superior protection of our freshwater resources.

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Colorado's Regulations On Wellbore Integrity And Hydraulic Fracturing

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Abstract

The Colorado Oil and Gas Conservation Commission (COGCC) currently has several rules, policies and procedures that, when implemented properly, are intended to result in wellbore integrity. "Wellbore integrity" is a system configuration, including casing, cement, annular fluid, and surface appurtenances (e.g., valves, piping, and emission control devices) to protect against infiltration and prevent the migration of oil, gas or water from one geologic horizon to another, that may result in the degradation of ground water.

COGCC has an active pre-construction and post-construction wellbore review process. The engineering staff preforms a pre-construction review of the casing and cement design to verify that the wellbore will be able to isolate fresh water from hydrocarbons. Field inspections occur during the drilling and completions phase to monitor and observation well drilling and completion phases through unannounced and random inspections. Post construction, the engineering staff perform a review of the as constructed casing and cement to verify that the approved permit to drill design was build and meets the criteria to isolate both fresh water and hydrocarbons zones. Wellbore integrity monitoring continues throughout well's productive life through bradenhead and mechanical integrity testing.

COGCC takes wellbore integrity very seriously. The current rules contain approximately 22 rules related to assuring the well's cement and casing can properly constructed to isolate and protect the fresh waters. Along with rules to monitor and maintain a well mechanical integrity, there are 11 policies several studies and defined procedures.

Introduction

The Colorado Oil and Gas Conservation Commission (COGCC) currently has several rules, policies and procedures that, when implemented properly, are intended to result in wellbore integrity. As discussed herein, "wellbore integrity" is defined as the ability of a wellbore system configuration, including casing, cement, annular fluid, and surface appurtenances (e.g., valves, piping, and emission control devices) to protect any potential oil or gas bearing horizons penetrated during drilling against infiltration of injurious waters from other sources, and to prevent the migration of oil, gas or water from one horizon to another, that may result in the degradation of ground water. These objectives of wellbore integrity are provided for in Rule 317.d.

An oil or gas well may be subjected to various stresses through the life of the well, and wellbore integrity must be maintained as these stresses are applied to the well. In general, there are four phases in the life of a well: drilling, completion, production and abandonment. COGCC has

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rules, policies and procedures to address wellbore integrity during each phase. The drilling phase commences after approval of a Form 2 (Application for Permit to Drill). COGCC engineering staff review Form 2's to verify that casing and cementing plans satisfy wellbore integrity criteria defined by Rule 317 and common industry practices specific to individual areas of the state.

Well Construction and Fluid Isolation

The COGCC engineering evaluation begins with a review of surface casing setting depths to ensure useable fresh water aquifers are isolated; and, well control is adequate per Rule 317.e. (areas with unknown subsurface conditions) or Rule 317.f. (areas with known subsurface conditions). For deep fresh water aquifers, cemented intermediate casing or production casing stage cement may be used to isolate the deep fresh water aquifers that are not otherwise isolated by cemented surface casing, Rule 317.g. Further, Rule 317.h. and Rule 317.i. require hydrocarbon producing zones to be isolated with cemented intermediate or production casing. Rule 317.h. and Rule 317.i. also require minimum strength standards and coverage intervals for surface, intermediate, and production casing cement.

A well is constructed with a combination of steel tubulars (casing) and cement to satisfy the wellbore integrity objective of zonal isolation. Steel tubulars (or "strings") are "telescoped" into the well as the wellbore is deepened. If necessary, a conductor pipe is used as the outermost string to keep the surface hole open while drilling and prevent collapsing (or "sloughing") of near-surface soil and unconsolidated rocks into the surface hole. Conductor pipe is not intended to provide isolation of fresh water aquifers. Conductor pipe is either driven into the ground or placed with cement in a drilled hole. The next smallest casing string is the surface casing, which is fully cemented and protects fresh water aquifers, except for deep fresh water aquifers that are otherwise protected by cemented intermediate casing or stage cement on production casing. Surface casing is also designed for sufficient depth to protect fresh water aquifers during possible well control events and as a foundation for placement of blowout prevention equipment that is used during drilling and workover operations. Depending on subsurface conditions, a smaller diameter intermediate casing is sometimes set and cemented inside and below surface casing to provide well control for weak deeper formations; to protect deep fresh water aquifers; to isolate lost circulation, to stabilize heaving or unstable zones; or to provide a rigid framework for hanging deep production liners, particularly in horizontal wells. The smallest diameter, innermost string is a production casing, which runs to surface or hangs off the bottom of an intermediate string as a liner. The primary purpose of the production string is to isolate producing hydrocarbon formations with cement to prevent migration of hydrocarbons and other fluids (e.g., hydraulic fracturing fluids) from the producing formation up the wellbore outside of the production casing. Figures 1 through 7 depict the drilling and installation process along with the related COGCC rules related to wellbore integrity. A summary of the COGCC engineering Form 2 review is presented as an exhibit to this summary, *Engineering Wellbore Review Procedure.*

The combination of steel and cement not only isolates fluid flow, but provide the compression, tension, collapse, and buckling strength necessary to maintain wellbore integrity in response to induced pressures applied to the well during drilling, completion and production activities. COGCC cement strength criteria are based on industry standards for compressive strength at 8

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hours and 72 hours. See Rule 317.h. and Rule 317.i. COGCC requires production casing to be pressure tested for conditions anticipated during completion and production operations, Rule 317.j.

COGCC may require remedial cementing when a well is being deepened, re-entered, or recompleted. In existing wells, where newly-defined subsurface conditions have been identified, COGCC will require remedial cement across fresh water aquifer or hydrocarbon bearing zones prior to completion of any new objective hydrocarbon formations. COGCC may require specific tests during these phases of operation, Rule 207. As an example, formation integrity tests are required after drilling below the surface casing in the East Mamm Creek Area (refer to the *Notice to Operators Drilling Mesaverde Group or Deeper Wells in the Garfield County, Well Cementing Procedure and Reporting Requirements, revised February 9, 2007).*

Post Construction Verification

After the well has been drilled, cased and cemented, the operator is required by Rule 308A to submit a Form 5 (Drilling Completion Report) reporting how the well was constructed. Figure 4 depicts a cased and cemented well. Operators are required to submit documentation of the work completed with Form 5. COGCC engineering staff reviews the documentation (well log data, service company reports, and operator daily field reports) to confirm that the conductor (if any), surface, intermediate (if any) and production casings were placed and cemented in accordance with the approved Form 2 and applicable COGCC rules and policies. If cement coverage is not adequate to provide proper isolation of fresh water aquifers and hydrocarbon producing zones, then remedial cementing and/or other corrective action is required, and enforcement actions are considered. COGCC requires a Cement Bond Log (CBL) to verify cement coverage behind the production casing or intermediate casing (if a production liner is used). Rule 317.o. Depending on the planned casing and cement configuration, COGCC staff may also require a CBL or temperature log for an intermediate casing string, even if a production casing string CBL is already required by rule. Figure 5 is an excerpt from a CBL showing the top of production casing cement. This geophysical log is a downhole tool run for the express purpose of evaluating the presence and quality of cement placed around casing.

COGCC also requires operators to file a Form 5A (Completed Interval Report). Rule 308B Form 5A includes information related to completed formations, depths, perforated intervals, and stimulation treatments. Figure 6 illustrates a graphic representation of a completed interval.

Well Integrity Monitoring

COGCC has several methods to monitor wellbore construction in the field during drilling, cementing, completion and production operations. COGCC engineering and field inspection staffs conduct unannounced and random inspections during all phases of these operations. Field inspections may also be conducted during specialized tests that are performed to demonstrate wellbore integrity, including bradenhead tests, mechanical integrity tests (MIT's) and formation integrity tests.

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Surface casing cementing inspections may be performed to verify that cement is placed along the entire length of casing through observation of visible cement returns at the surface outside of the surface casing. With the cemented surface casing isolating the fresh water zones, drilling will continue for the intermediate or production hole.

During drilling, the production hole stability is maintained by the fluid weight of the drilling mud and the resulting mud cake that is formed on the borehole wall. After the target hydrocarbon zone has been reached in the production hole, the production casing is placed and cemented in the hole to isolate the hydrocarbon producing formations. COGCC staff may conduct unannounced and random field inspections while the production hole is being drilled, or while production casing is being run and cemented to monitor compliance with COGCC rules.

The next phase of monitoring is during the completion (a.k.a., stimulation or hydraulic fracture treatment). COGCC engineering and field inspection staffs conduct unannounced and random inspections to observe these operations. Rule 341 requires continuous bradenhead (the annulus between the surface casing and the production casing) pressure monitoring and recording during all stimulation operations. The rule further states that the stimulation fluids shall be confined to the objective formations during treatment. If the bradenhead annulus pressure increases more than 200 psig at any time during stimulation, the operator shall verbally notify COGCC as soon as practicable. Upon receipt of any high bradenhead pressure notices, COGCC engineering staff reviews the pressure data to determine if any remedial action is necessary. The operator is required to perform remedial work if wellbore integrity was compromised. Within the Wattenberg Field, COGCC has established an adjacent wellbore policy for bradenhead monitoring during hydraulic fracturing treatments of horizontal wells within 300 feet of an existing well.

Tests may be performed periodically during a well's productive life to monitor wellbore integrity. Bradenhead tests and MIT's are two examples. Bradenhead monitoring is an indirect method to verify wellbore integrity, and is defined by Rules 207.b. and 608.e. Bradenhead testing is the pressure monitoring of wellhead access to the annulus between the production and surface casing, as depicted in Figure 8. The wellhead annuli are equipped with fittings to allow safe and convenient access for pressure and fluid flow monitoring. The objective of the test is to check for pressure differential between the annular space and the casing and to observe any fluid flow (gas, oil, and/or water) up the annulus, which could be indicative of a casing leak. If a casing leak is suspected, then a MIT could be performed for verification.

Bradenhead monitoring of all coalbed methane (CBM) wells is required on a biennial basis. Rule 608 CBM bradenhead monitoring is performed per COGCC Orders in the San Juan and Raton Basins. Further, COGCC used Rule 207 to define special bradenhead areas. There are two Commission designated testing areas in addition to the San Juan and Raton Basins: Piceance Basin (refer to *Notice to Operators Drilling Wells in the Buzzard, Mamm Creek, and Rulison Fields, Garfield County and Mesa County, Procedures and Submittal Requirements for Compliance with COGCC Order Nos. 1-107, 139-56, 191-22, and 369-2*, dated July 8, 2010) and the *Special Bradenhead Testing Area in Weld County, established on December 16, 2009.*

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MIT's, as described in Rule 326, are required for all shut-in, temporarily abandoned, or injection wells. The test is required at 5-year intervals. The test is performed by filling the casing (and/or the casing-tubing annulus on injection wells) with water or gas and applying a designated test pressure to the casing, as shown on Figure 9. The surface pressure is observed for 15 minutes to monitor for possible leak off. Wellbore integrity is confirmed if significant leak off is not observed. Conversely, if the test fails, the well is required to be repaired or abandoned. The requirement to maintain mechanical integrity is further enhanced by Rule 317.j. which requires the production casing to be pressure tested for the conditions anticipated during completion and production operations.

Wells lacking mechanical integrity or wells that are no longer capable of production are required to be abandoned per Rule 319 and Rule 326.d. The downhole abandonment procedure requires all water, gas or oil zones to be isolated and fluids to remain in their respective formations, as shown on Figure 10. To meet this requirement, mechanical or cement plugs are placed above and/or below hydrocarbon and fresh water aquifers. COGCC engineering staff reviews a Form 6 (Notice of Intent to Abandon) prior to plugging and abandonment to verify proper plug placement. This review is similar to a Form 2 engineering review, as discussed above, to identify all fresh water aquifers and hydrocarbon producing zones.

Conclusions

COGCC has an active pre-construction and post-construction wellbore review process. A field inspection program occurs during all phases of well and surface facility construction, operation, abandonment, decommissioning, and reclamation through unannounced and random inspections. Monitoring processes include a variety of downhole test procedures. The oil and gas extraction industry is dynamic with evolving technology. COGCC staff considers current rules and policies adequate to create, maintain, and demonstrate wellbore integrity. However, periodic review of COGCC's wellbore integrity rules, polices, and procedures are necessary to keep in step with the oil and gas extraction industry.

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WELL BORE DIAGRAM
DRILL OUT FOR SURFACE CASING
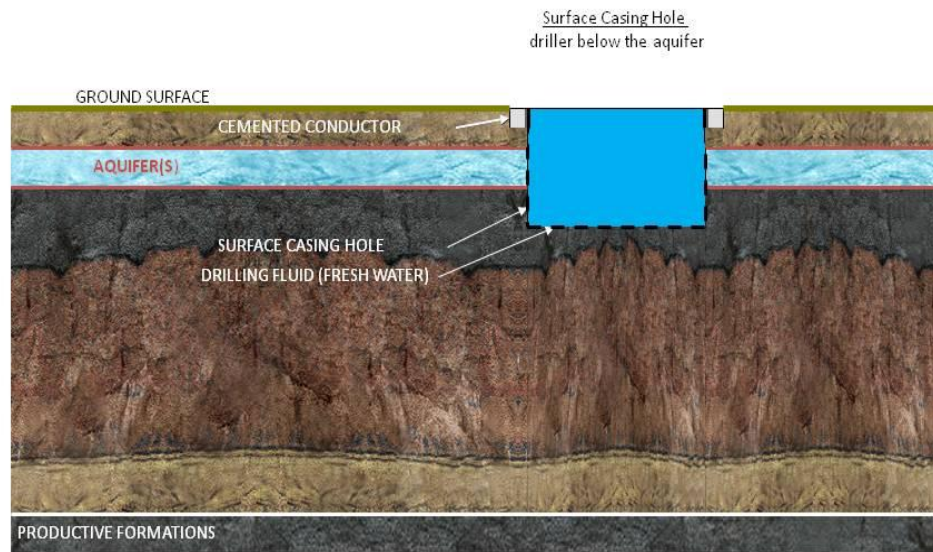With fresh water to protect the aquifers

Figure 1

WELL BORE DIAGRAM
PLACE & CEMENT SURFACE CASING
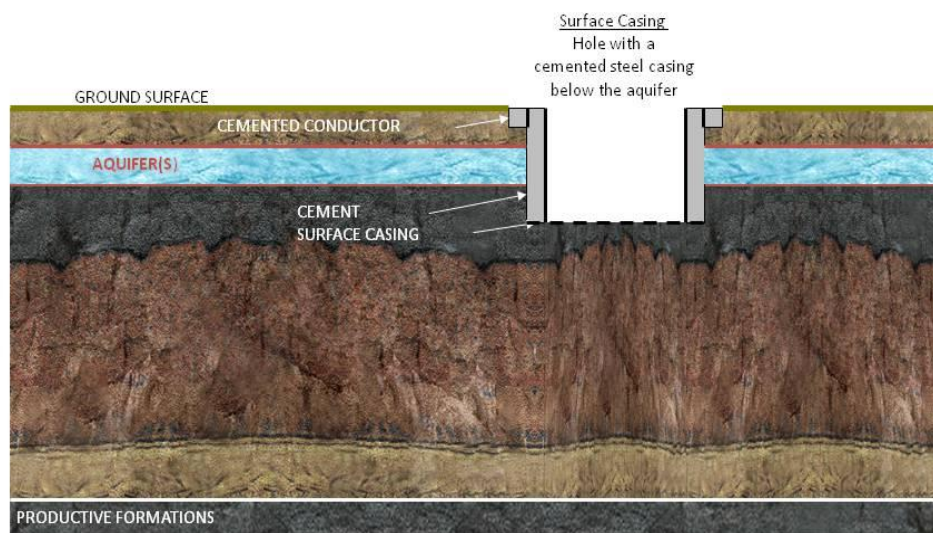To Protect Aquifers
Per COGCC Rules 317.e, f, g, & h

Figure 2

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WELL BORE DIAGRAM
DRILL OUT FOR PRODUCTION HOLE
Fluid inflow control by drilling fluid weight
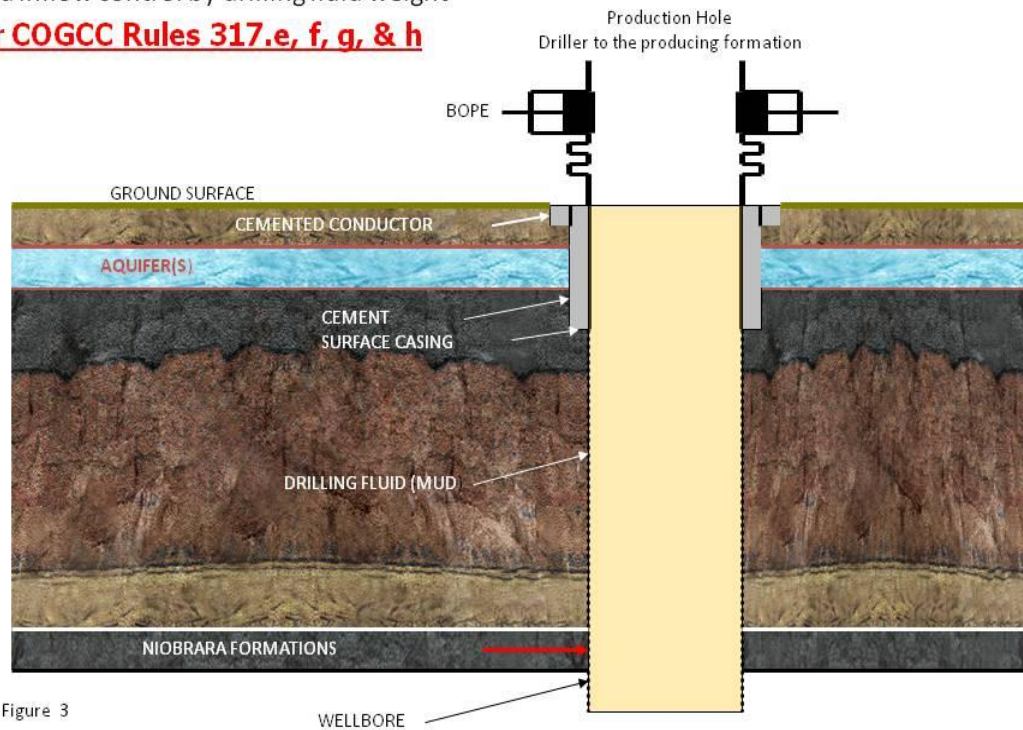**Per COGCC Rules 317.e, f, g, & h**

Figure 3

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Figure 4

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Cement Bond Logs to verify placement of cement

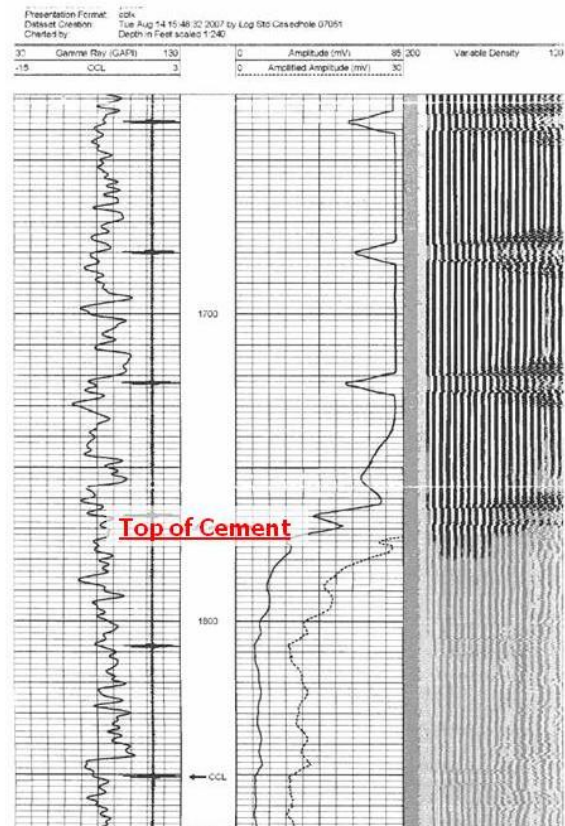**Per COGCC Rule 317.o** requires cement bond logs for all wells.

Figure 5

WELL BORE DIAGRAM
PREPARE FOR PRODUCTION
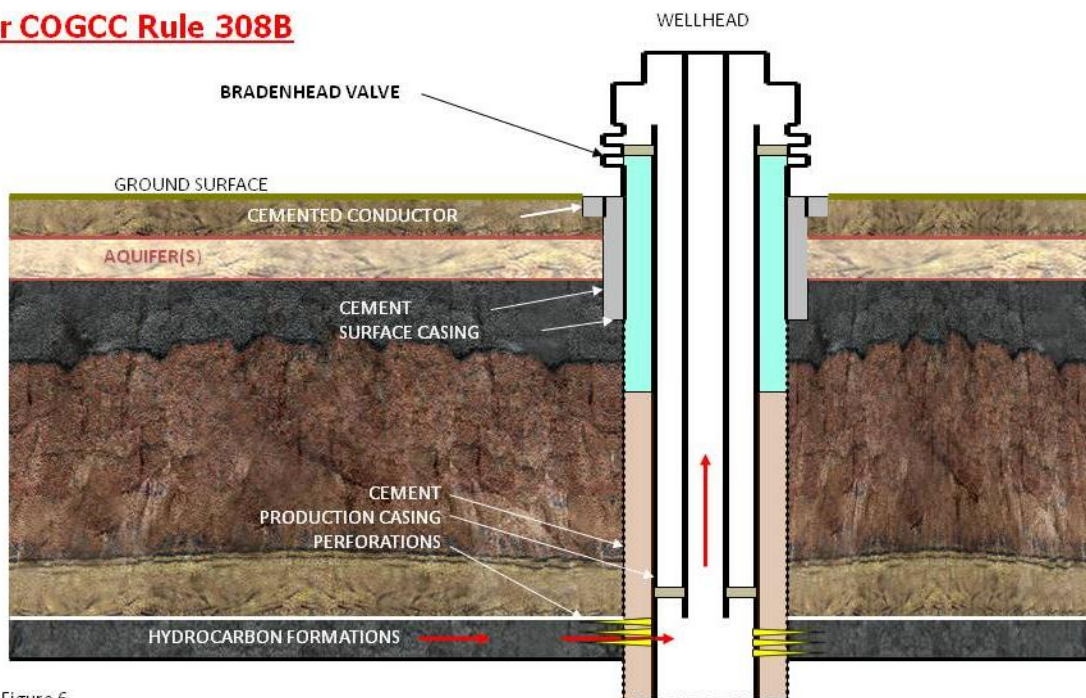Perforate and run tubing

Per COGCC Rule 308B

Figure 6

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WELL BORE DIAGRAM
STIMULATION – Hydraulic Fracture
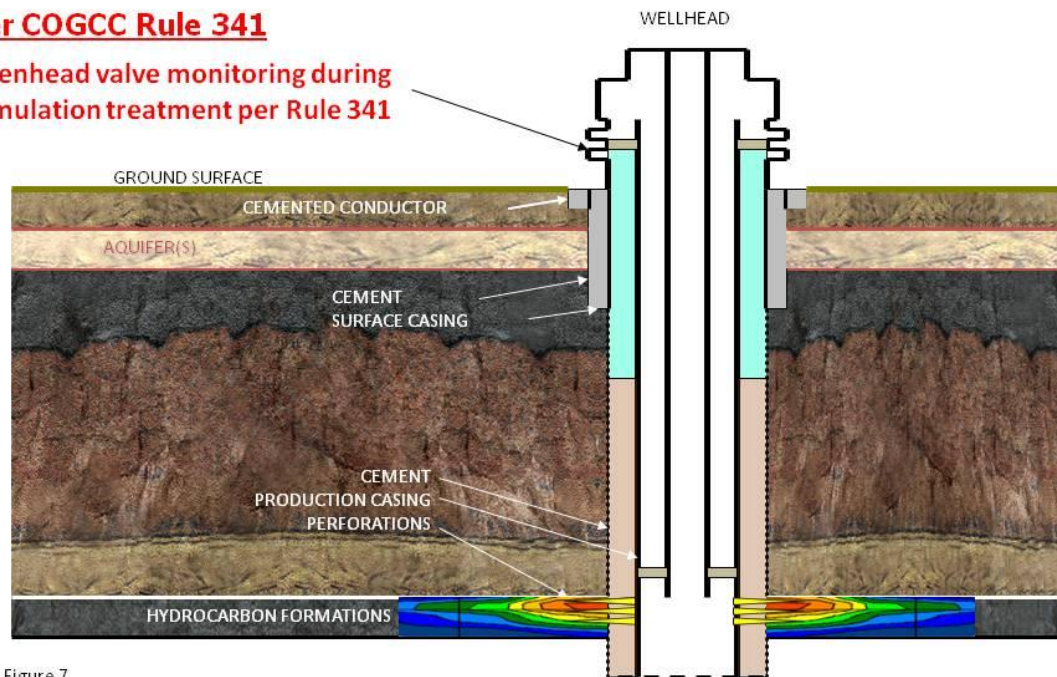
Figure 7

BRADENHEAD MONITORING TEST
Monitoring for internal annulus pressure

Figure 8

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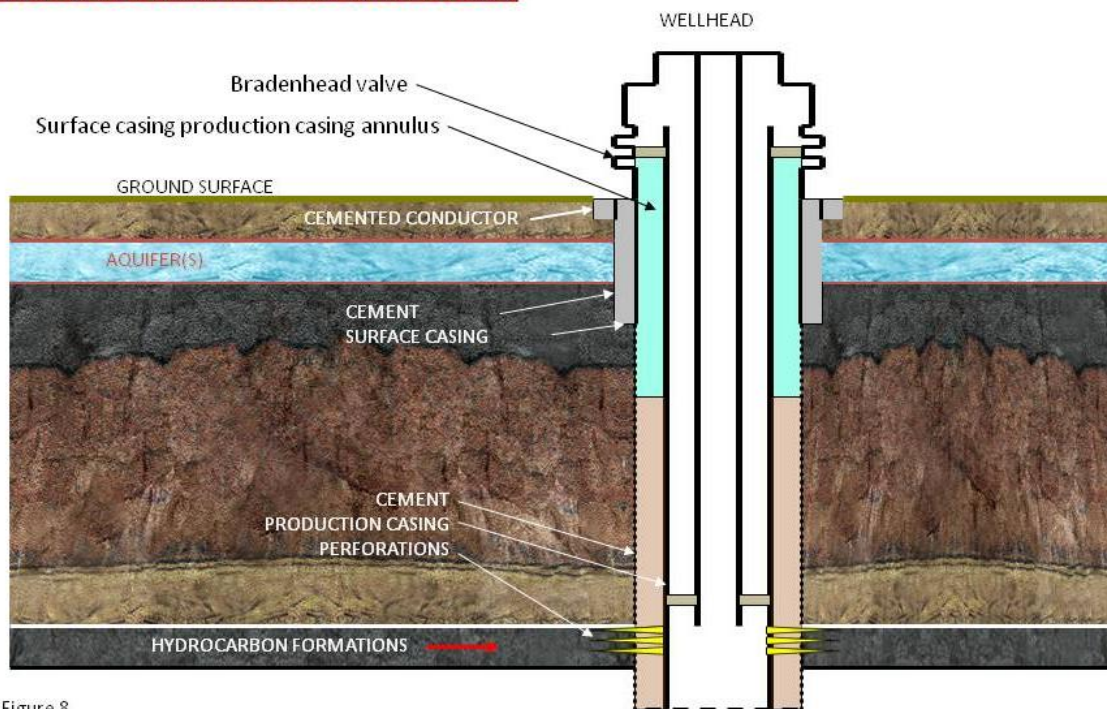June 3, 2013, Subsurface Modeling Technical Follow-up Discussion

MECHANICAL INTEGRITY TEST

Applied pressure monitoring of internal casing pressure

Per COGCC Rule 326

Figure 9

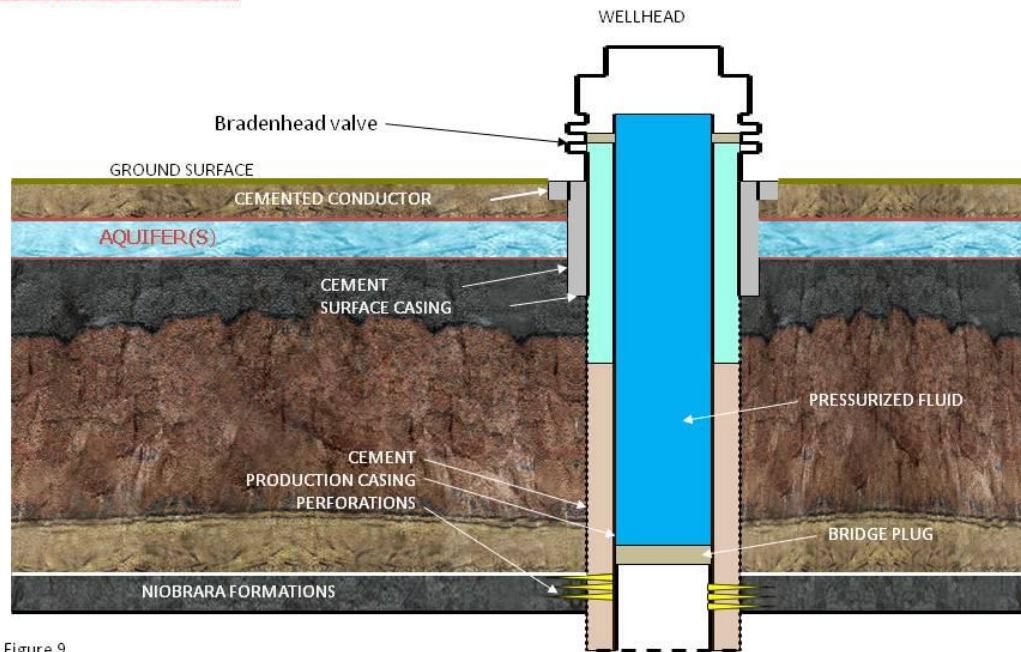EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources:
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WELL ABANDONMENT

Rule 319: Isolation of fresh water and hydrocarbon zones

CASING CUT 4-FEET
BELOW GRADE
WITH A CEMENT PLUG
AND STEEL PLATE CAP

GROUND SURFACE

CEMENTED CONDUCTOR

AQUIFER(S)

CEMENT
SURFACE CASING

CEMENT OR
MECHANICAL
BRGDE PLUGS

CEMENT
PRODUCTION CASING
PERFORATIONS

HYDROCARBON FORMATIONS

Figure 10

EPA's Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources:
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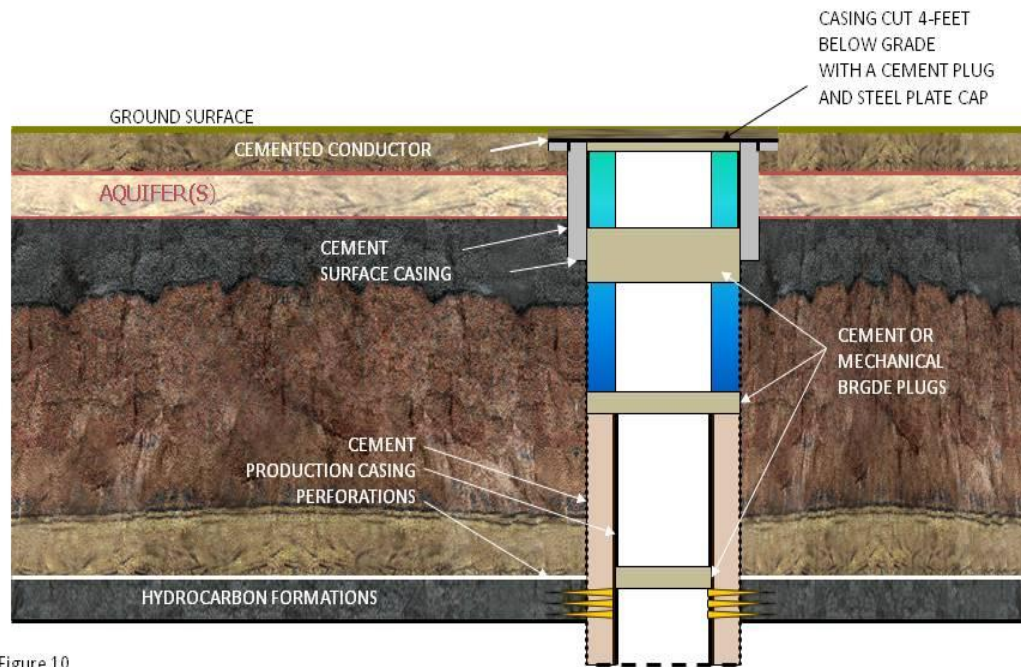June 3, 2013, Subsurface Modeling Technical Follow-up Discussion

CURRENT COGCC RULES RELATED TO WELLBORE INTEGRITY:

This section provided a list of most of the current COGCC rules related to wellbore integrity.

207.	TESTS AND SURVEYS
301	RECORDS, REPORTS, NOTICES-GENERAL
303	REQUIREMENTS FOR FORM 2, APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE; FORM 2A, OIL AND GAS LOCATION ASSESSMENT.
308A	COGCC Form 5. DRILLING COMPLETION REPORT
308B	COGCC Form 5A. COMPLETED INTERVAL REPORT
309	COGCC Form 7. OPERATOR'S MONTHLY PRODUCTION REPORT
311	COGCC Form 6. WELL ABANDONMENT REPORT
314	COGCC Form 17. BRADENHEAD TEST REPORT
316A	COGCC Form 14. MONTHLY REPORT OF NON-PRODUCED WATER FLUIDS INJECTED
316B	COGCC Form 21. MECHANICAL INTEGRITY TEST
316C	NOTICE OF INTENT TO CONDUCT HYDRAULIC FRACTURING TREATMENT
317	GENERAL DRILLING RULES

        a. Blowout prevention equipment ("BOPE").
        c. Requirement to post permit at the rig and provide spud notice
        d. Casing program to protect hydrocarbon horizons and ground water.
        e. Surface casing where subsurface conditions are unknown.
        f. Surface casing where subsurface conditions are known
        g. Alternate aquifer protection by stage cementing
        h. Surface and intermediate casing cementing.
        i. Production casing cementing.
        j. Production casing pressure testing.
        k. Protection of aquifers and production stratum and suspension of drilling operations before running production casing.
        m. Protection of productive strata during deepening operations.
        n. Requirement to evaluate disposal zones for hydrocarbon potential
        o. Requirement to log well
        p. Remedial cementing during recompletion.

317A	SPECIAL DRILLING RULES - D–J BASIN FOX HILLS PROTECTION AREA

        a. Surface Casing - Minimum Requirements for Well Control.
        b. Surface Casing - Aquifer Protection.
        c. Exploratory Wells.

319	ABANDONMENT
321	DIRECTIONAL DRILING
325	UNDERGROUND DISPOSAL OF WATER
326	MECHANICAL INTEGRITY TESTING
327	LOSS OF WELL CONTROL
341	BRADENHEAD MONITORING DURING WELL STIMULATION OPERATIONS
404	CASING AND CEMENTING OF INJECTION WELLS

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603   DRILLING AND WELL SERVICING OPERATIONS AND HIGH DENSITY AREA RULES

608e. COALBED METHANE WELLS Bradenhead testing.

Current COGCC Policies:

1. COGCC Policy for Bradenhead Monitoring During Hydraulic Fracturing Treatments in the Greater Wattenberg Area, dated May 29, 2012
2. Practices and Procedures, UIC Mechanical Integrity Tests, dated March 17, 2011
3. Notice to Operators Drilling Williams Fork Formation Wells in Garfield County, Surface Casing Depth and Modification of Leakoff Test Requirements, revised June 23, 2006
4. Notice to Operators Drilling Mesaverde Group or Deeper Wells in the Mamm Creek Field Area in Garfield County, Well Cementing Procedure and Reporting Requirements, revised February 9, 2007
5. Notice to Operators Drilling Wells in the Buzzard, Mamm Creek, and Rulison Fields, Garfield County and Mesa County, Procedures and Submittal Requirements for Compliance with COGCC Order Nos. 1-107, 139-56, 191-22, and 369-2, dated July 10, 2010
6. Notice to All Oil and Gas Operators Active in the Denver Basin, Colorado Oil and Gas Conservation Commission Approved Wattenberg Bradenhead Testing and Staff Policy, dated December 16, 2009
7. Drilling Completion Report - Cement Documentation Policy, February 17, 2009
8. Clarification on Procedures for Filing Changes to Applications for Permit-to-Drill, revised January 18, 2011
9. Conductor Pipe Setting Policy, April 6, 2006
10. Approval of Casing Repairs Policy
11. Northwest Colorado Notification Policy, Effective for Notices Received On or After January 1, 2010, Revision No. 3, May 10, 2012

COGCC STUDIES:

1. COGCC Mamm Creek Area Cementing and Bradenhead Pressure Monitoring Practices, staff presentation to Commission dated September 19, 2011
2. COGCC Response to the conclusions and recommendations in the June 20, 2011 *East Mamm Creek Project Drilling and Cementing Study*, memorandum dated September 19, 2011
3. East Mamm Creek Project Drilling and Cementing Study, consultant report dated June 20, 2011

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Simple Groundwater Modeling of Transport Pathways in Unconventional Natural Gas Plays

Tom Myers
Great Basin Hydrology

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The claims made by participants have not been verified or endorsed by EPA.*

Introduction

Groundwater modeling using MODFLOW-2000 has suggested that vertical flow of contaminants from the Marcellus Shale to shallow aquifer layers can occur within time frames of interest to water resource managers, if proper conditions are met (Myers 2012). These conditions include an upward vertical gradient and a pathway, which could include fractures or improperly abandoned wells. Data subsequently published has also suggested that Marcellus formation brine has been found in shallow aquifers (Warner et al 2012). Myers basic hypothesis was that it is possible for fluids released from the Marcellus Shale or other deep nonconventional shale formations to move vertically to aquifers sufficiently shallow to affect groundwater-dependent water resources. The modeling considered the movement of contaminants once they were out of the Marcellus Shale, whether by out-of-formation fracturing or by fluid movement through natural fractures to the interburden. It also applies to well-bore leaks deep in the well.

The modeling included potential oversimplifications including whether the flow is Darcian, how imbibition may affect the modeling, multiphase flow, and the effect of boundaries. This presentation focuses on the assumptions and data required for simple MODFLOW-based modeling of potential pathways.

Darcian Flow

Darcy's Law accurately describes groundwater flow as long as the relationship between specific discharge and hydraulic gradient is linear (Bear 1979). The conductivity in the basic form of Darcy's law is a coefficient of proportionality. Darcy's law is also valid where viscous flow predominates, or between microscopic and turbulent effects.

At a scale where microscopic flow predominates, Darcy's law would not be valid. For shale, this is at the laboratory scale of a permeameter wherein a core sample with a radius of a few centimeters is tested. In shale, and other consolidated rock, conductivity within samples too small to include fractures is extremely low and may legitimately not be considered to be Darcian flow. As the size increases, a sample may begin to include fractures; the larger samples are collected at a field scale through pump tests or even through a calibrated groundwater model. A representative elemental volume (REV) is a volume for which conductivity, or porosity, is relatively constant through the volume (Bear 1979). This is the point at which the proportion of media and fractures becomes relatively constant; the upper limit is the volume at which heterogeneity, the inclusion of differing rock types or fracture densities, begins to affect the conductivity.

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A media can exhibit three types of flow within the REV – porous, fracture or a double porosity or combined flow behavior. Devonian shale exhibits fracture flow (Schulze-Makuch et al. 1999), and there is an upper limit to the volume scale at about 10^7 m^3. Drawdown from pumping in a fracture flow system continues to increase within the limits of the fracture or if modeling the limits of the model cell. Figure 1 shows scale relationships for various materials. The figure shows that as volume (and fractures) increase in Devonian shale, the relative conductivity also increases. This would be representative of pre-fracked shale.
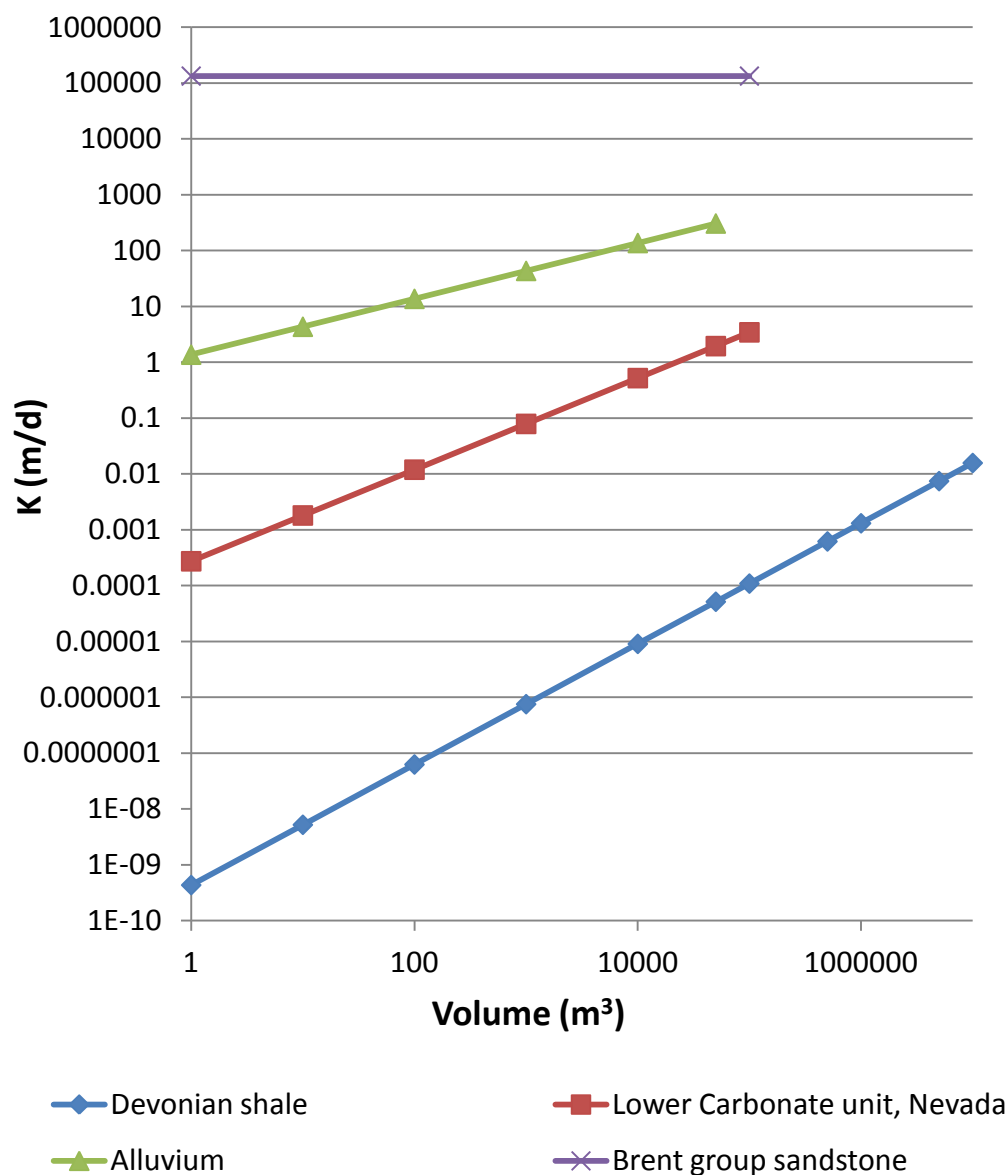
Figure 1. Scale relationship of Marcellus Shale and three other formations. The lower volume is set to 1 m3. The upper limit is the upper bound. All relationships from Schulz-Makulch (1999).

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Multiphase Flow

Fluids in the Marcellus Shale exist in at least two phases. The methane in the small bulk media pores are one phase and the naturally occurring brine is another although due to the variable densities of the brine there may be effectively multiple phases. The primary effect of the gas on fluid flow would be to reduce the effectively permeability for water flow. The methane gas is bound within microscopic pore spaces and may effectively lower the permeability within the bulk media even more so than when considering single-phase fluid flow. As far as modeling the flow of liquids in the shale and interburden, fractures control. It is very unlikely that significant gas exists in the fractures in either the shale or overlying interburden, whether sandstone, mudstone, or shale. Therefore it is unlikely to affect flow at the scale being considered herein.

Imbibition

Imbibition is the absorption and adsorption of the fracking fluid into the pores of the rock, specifically the Marcellus Shale in this example. Imbibition would include fracking fluid displacing methane gas, thus the ratio of fluid to gas in the multiphase flow system would increase. MODFLOW modeling does not simulate this loss of fluid. The fact that there is flowback and out-of-formation fractures demonstrates that not all fluid imbibes. The modeling here is of how changes in the hydrogeology can affect over all fluid movement in the system. However, the transient solutions including injection of fluids should account for some of the injected fluid being bound in the capillary fraction of the shale media.
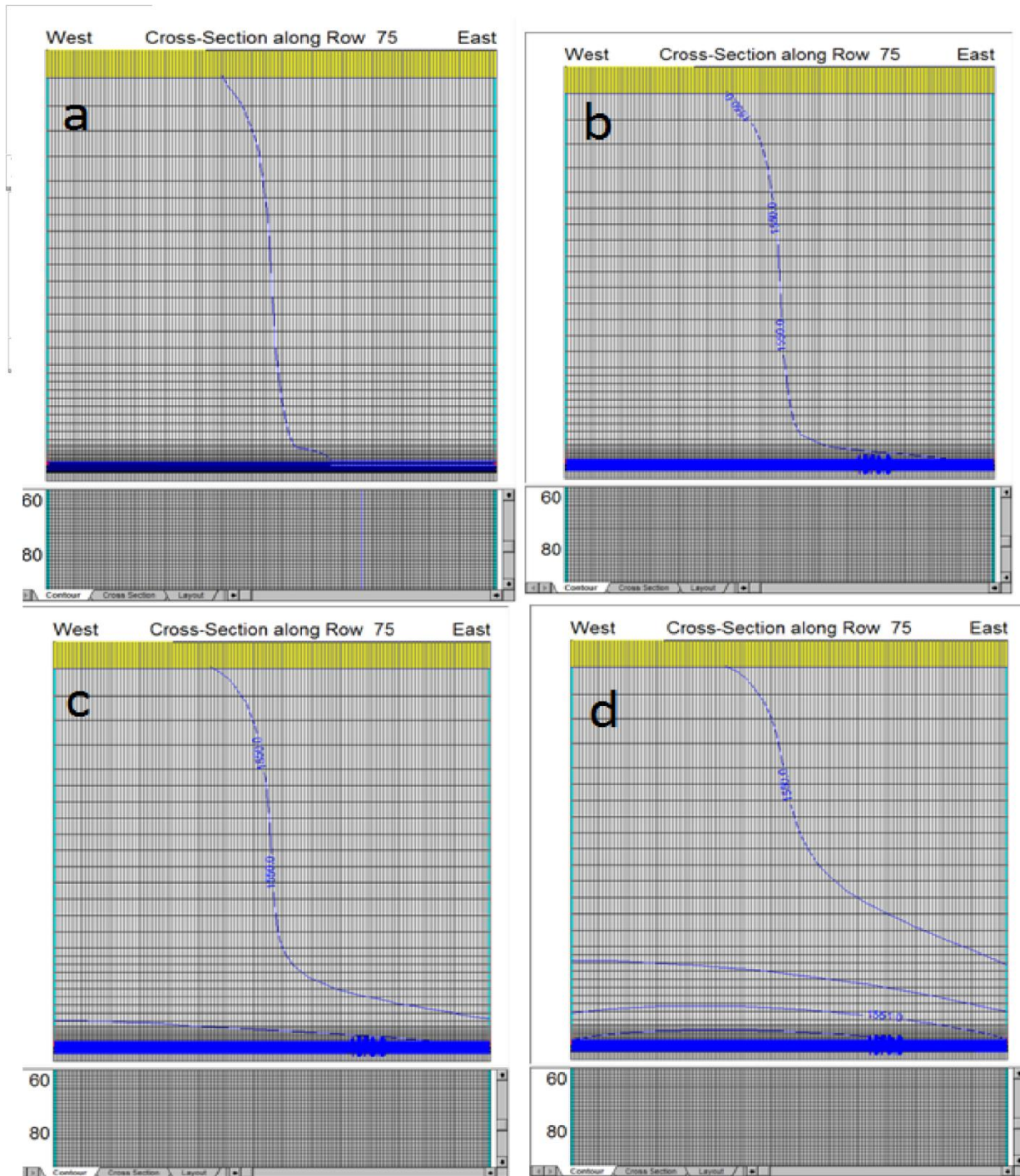
Boundary Conditions

A primary objection had been that the model was too one-dimensional being bounded by no flow boundaries and having the gradient established with constant head boundaries. This was tested by changing one of the CH boundaries to a drain and by adding head-dependent flux boundaries to two sides to allow horizontal flow. The original model (Myers 2012) had three 3 m square cells with 150 rows and columns creating a 450 m square domain; vertically, the domain was 1550 m with a 30 m head drop from the bottom of the domain to the surface, meaning there was simulated upward pressure. Details on conductivity values may be found in Myers (2012). At large differences in very small conductivities, an overall water balance error in the solution had increased even though the model would converge. The PCG2 solver was used with head and residual criterion each at 0.001. The overall water balance error was reduced in this analysis by increasing the number of inner iterations from 25 (as used in Myers (2012)) to 50 for these analyses.

The first boundary condition tested is the use of a drain boundary for the surface conditions in scenario 1 (Myers 2012). A drain boundary when used at the ground surface can emulate discharge to a stream or wetland or evapotranspiration depth with an extinction depth equal to the difference in the stage and water level. Starting with Scenario 1 (Myers 2012), which is shale and overburden with K = 0.00001 m/d and 0.1 m/d, respectively, the vertical flux was about 2.0 m^3/d, or about 5% higher than when using constant head boundaries and within a few percent of the empirical calculations.

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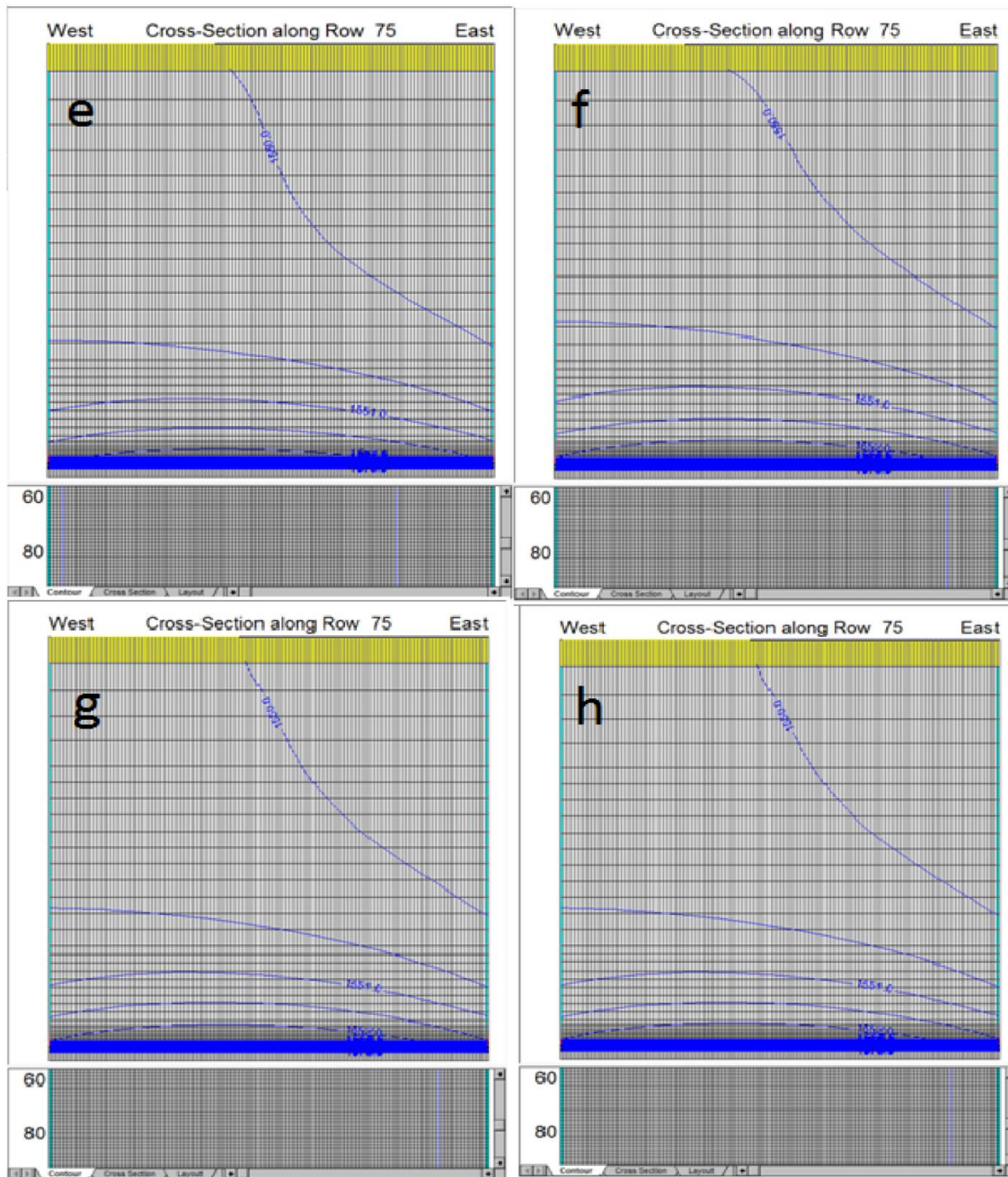June 3, 2013, Subsurface Modeling Technical Follow-up Discussion

The second addition was general head boundaries (GHBs) on two sides to add a horizontal flow to the simulation. The GHBs established a 1 m head drop over 850 m (slope approximately 0.0012) with a conductance equal to the product of the layer thickness and conductivity. At steady state, the vertical flux through the shale from the lower constant head boundary was 2.02 m^3/d, but the flux through the drain on the top layer increased to 5.97 m^3/d; the additional water was from the GHBs, which simulated an inflow to and outflow from the domain to be 78.0 and 74.1 m^3/d.

Scenario 3 (Myers 2012) was a transient simulation to show how much and how fast the upward flux would change if the properties of the shale changed due to fracking. One assumption is that fracking extends to the edge of the shale, but not into the overburden; it does not consider out of formation fracking. It also does not consider the changes due to injecting additional fluids into the shale. Storage coefficient for the overburden and fracked shale was 0.0001 and 0.001; the value for the shale was criticized but had been set to represent storage properties during or just after fracking, although it is likely that over the long-term compression may reduce the value; it was also considered conservative, a means to temporarily allow more water to be bound in the shale.
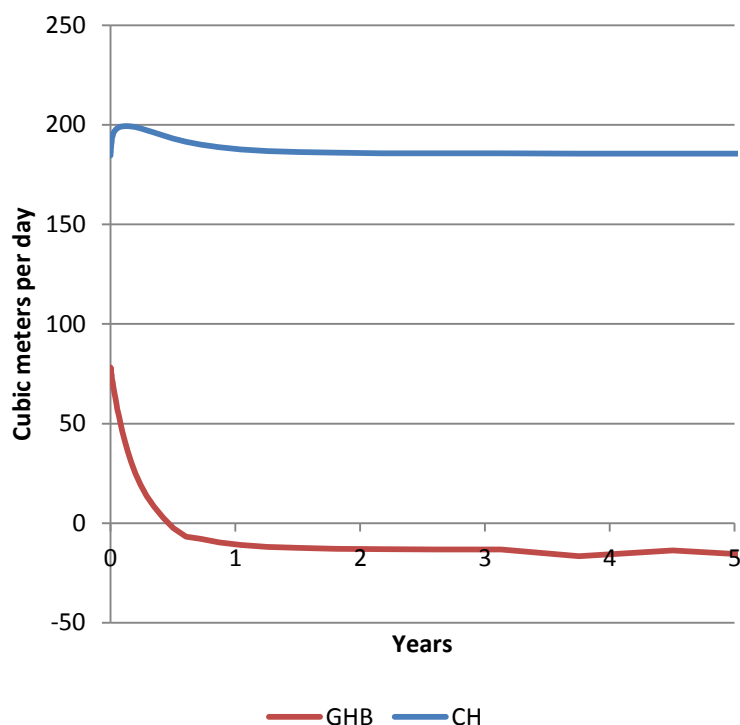
Using the steady state model run with GHBs described above as initial conditions, the shale K was changed to 0.001 m/d and the simulation run for 100 years. A time series of cross-sections showing the evolution of the potentiometric surface demonstrates how changing the shale properties could change the potentiometric surface in three-dimension, instead of the simple one-dimensional solution presented by Myers (2012). Figure 2 shows the vertical pressure changes analogous to those shown by Myers (2012) but with a horizontal component superimposed. Just after the simulation begins, the almost vertical contour for 1550 m (Figure 2a) shows the majority of the flow is horizontal as determined by the steady state solution for pre-fracking conditions discussed above. The changes to a more horizontal component to the 1550 m contour (Figure 2b and 2c) and the addition of 1550.5 and higher contours (Figure 2c through 2h) show the adjustments with time. The primary adjustment is from the steady state, pre-frack, head drop across the shale of almost 30 m to a lesser drop of about 27 m necessary for a two-order of magnitude increase in K due to fracking.

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Figure 2. Potentiometric surface in the cross-section 0.12 day (a), 0.96 day (b), 9.3 days (c), and 61 days after the start of the simulation.

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Figure 2 (cont.). Potentiometric surface in the cross-section 153 days (e), 584 days (f), 14,670 days (c), and 36,500 days after the start of the simulation.

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Figure 3. Hydrograph of the change in horizontal flow through the model n(GHB) and in discharge through the shale (CH).

The flow through the shale can be represented by a change in flow from the constant head (CH) boundary that simulates the pressure to drive flow through the shale. That flow adjusts very quickly from 2.0 to more than 100 m^3/d due to the changed conductivity in the shale just above the boundary (Figure 3). Almost half of the change in CH flow is a change in horizontal flow through the model. Because of pressure differences, some of the flow through the shale goes in the previously up-gradient direction and more continues downgradient. Essentially, the flow through the shale replaces some of the horizontal flow through the model domain.

An obvious question is whether this is reasonable. Over the small domain and the extremely small amounts of flow being discussed, it is reasonable. A 100 m^3/d flux is less than 0.2 m/y over the 450 m square domain, which is not much of an adjustment. The horizontal flux considered here does not obviously change the vertical flow velocities simulated (Myers 2012) but simply indicates that contaminants could move downgradient in addition to the vertical movement. Faults both provide pathways (Warner, et al. 2012) and could speed the contaminant velocity.

Conclusion

This analysis discusses and tests some of the various objections to the assumptions used to test the hypothesis regarding the potential for vertical fluid flow from deep shale to near-surface aquifers in Myers (2012). While details can and certainly will continue to be debated, none of the assumptions cause a rejection of the hypothesis and new analyses (Warner, et al. 2012) may

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actually document movement of fluids from depth. The most important recommendation resulting from the modeling of potential fluid flow is that monitoring must occur, not just of the potential receptors (producing water wells) but of the aquifers and fracture zones between the targeted shale and the surface aquifers.

References

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Osborn, S.G., A. Vengosh, N.R. Warner, and R.B. Jackson. 2011. Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proceedings of the National Academy of Sciences* pnas.1100682108.

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Warner, N.R., R.B. Jackson, T.H. Darrah, S.G. Osborn, A. Down, K. Zhao, A. White, and A. Vengosh. 2012. Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania. *Proceedings of the National Academy of Sciences* pnas.1121181109.

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Long Term Risk of Potable Aquifer Contamination via Fracking Fluids

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The claims made by participants have not been verified or endorsed by EPA

Introduction

The long-term risks of environmental degradation due to the transport of hydraulic fracturing fluids to potable aquifers are a critical problem. Because assessment of these risks is only possible through the use of a mathematical model that calculates the *probability distribution* of contaminants in potable aquifers which, in turn, will define the hazard associated with that aquifer, the development and application of such a model is *crucial*.

Current Knowledge: In general the migration to potable aquifers of fluids associated with the recovery of natural gas from low permeability formations via hydraulic fracturing is considered by the general public to be a serious environmental threat. It is well known that hydraulic fracturing involves injecting hydraulic fracturing fluids into the subsurface until the pressure exceeds that required for fracture generation or expansion. Formations where hydraulic fracturing is done are generally thousands of feet below the surface and far below practically usable potable aquifers (**UPA**). During the hydraulic fracturing process there is little likelihood of hydraulic fracturing fluids reaching UPAs because the hydraulic fracturing process is of short duration. During gas production, the hydrofracked region is under negative pressure relative to hydrostatic so hydraulic fracturing fluids will tend to be contained. However, this will not be the case once petroleum extraction ceases. The reason is that in some areas the undisturbed, pre-hydraulic fracturing, fluid-potential gradient is such that there is natural flow from the hydraulic fracturing location to the surface. After shutdown the post-hydraulic fracturing fluid potential will gradually return to its natural state and, if the fluid flow was originally generally upward, it will return to upward flow. The groundwater flow velocity may now very well increase relative to its pre-development state due to the presence of the hydrofracked rock. Fractures induced by hydraulic fracturing will create a network that will generally intersect pre-existing faults, joints and potentially abandoned wells. When the pre-hydraulic fracturing fluid potential is re-established the possibility will exist for residual hydraulic fracturing fluids to utilize these preferential pathways to move upwards. Such upward migration may impact potable water supplies.

The quantification of such risk requires the use of fluid-flow and mass-transport models. In our work, risk is defined by the probability of exceeding a target concentration in a UPA and its potential health impact as a function of time. Contaminant concentration is used as a surrogate for health impact. To assess risk in this context it is *essential* that models not only describe the movement of hydraulic fracturing fluids laden with proppant, but to do so when the parameter values describing the physical characteristics of the subsurface system are uncertain. Previous calculations used to predict the impact of hydraulic fracturing fluids on UPAs have used deterministic, not stochastic models.

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They have focused on using 'worst case' scenarios to establish plausibility of impact. While such an approach is a good first step, it does not lead to an estimate of risk.

Discussion

Gap in knowledge: What is not known is how to calculate the risk associated with hydraulic fracturing fluid migration. A *critical need* is a modeling capability that can predict the long-term movement of hydraulic fracturing fluid in the subsurface when the uncertainty in hydraulic conductivity that is inherent in the fractured reservoir is accommodated. Such a capability requires 1) a mathematical model capable of solving the equations describing a system with uncertain coefficients and 2) a reasonable estimate of the uncertain hydraulic conductivity coefficients.

An important problem: In the absence of this modeling capability and a reasonable estimate of the uncertain field parameters it is not possible to calculate the mean concentration of hydraulic fracturing fluid and its associated uncertainty due to transport. Thus it is also not possible to calculate the concentration of hydraulic fracturing fluid reaching the UPA *in the presence of a natural long-term upward movement of groundwater*. Without this probability distribution it is not possible to calculate the risk as defined above. Lack of knowledge regarding this issue is important because without a defensible estimate of this risk, the controversy over the safety of the hydraulic fracturing process cannot be resolved.

Long-term goal: The long-term goal of our research is to establish the risk of hydraulic fracturing fluid contamination of UPAs, especially in the long term (tens to hundreds of years); this requires the calculation of the probability of contaminants reaching such aquifers and their associated concentrations.

Rationale: The very rapid expansion of hydraulic fracturing for gas recovery has proceeded in the absence of a publicly accepted estimate of the risk to water supplies and the risk of surface expression. The need for such an analysis is urgent given the tendency of State governments to respond in a knowledge vacuum in deciding to possibly ban hydraulic fracturing. The critical need is to build upon current preliminary analyses made by others using deterministic models to provide an analysis that includes uncertainty which is required to establish risk. Recall that we have defined. In addition, it is essential that any such analysis consider the long-term impact of natural upward groundwater movement. When these goals are realized the resulting information will assist decision makers in their deliberations so that they can provide more informed decisions regarding hydraulic fracturing than are now possible.

Model Development: To date we have conducted a literature review and have made initial mathematical formulations of a model that will allow us to represent discrete fractures oriented at any angle as a smooth plane in an otherwise continuum based finite-element-volume formulation. The basic idea is to embed planar finite-element-volumes into otherwise three-dimensional finite-element-volume coefficient matrices. The embedded two-dimensional element-volumes will represent the fracture plane and will have hydrodynamic and physical properties indicative of the fractures. In this way the dislocations can be incorporated directly into the formulation so that no additional computational effort over what is needed for a continuum model is required to solve the equations. Our initial studies have focused on a finite-

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element formulation, however we will also explore the possibility of using a finite-element finite-volume formulation employing the same concept. The finite volume method has the advantage of exact mass conservation properties.

Random-Field for Near Field Fracture Network Permeability: Two random fields are needed for this project. One is the near field fracture hydraulic conductivity; this is the continuum representation of hydraulic conductivity that is attributable to the man-made fractures induced by hydraulic fracturing. There is also a hydraulic conductivity associated with the blocks that are contained by the fractures, but will assume a deterministic value for this parameter. As mentioned above, the information that is available for the near-field fractures is very limited, but one series of papers provides several sets of field measurements based upon geophysics and state of the art monitoring techniques conducted by Pinnacle Technologies. We have obtained from Prof. Richard Davies digitized values of fracture lengths which we have analyzed to establish their statistical properties. Figure 1 shows the probability of occurrence of fractures of different lengths measured relative to the boring. They clearly fit a log-normal distribution. With this information and an informed value of their correlation, we will be able to provide the statistics needed to generate a random field of hydraulic conductivity emanating from the boring used for hydraulic fracturing.

Random Field for Far-Field Fracture Permeability: The far-field fracture network is composed of pre-testing faults, joints and other large-scale dislocations. In three-dimensional formulations abandoned well bores would also be considered in this category. For the faults, joints and other large-scale dislocations we will create discrete fractures, not a representative continuum such as discussed in the preceding subsection. To use a Monte Carlo approach to compute uncertainty, it is important that it be possible to rapidly create realizations of fracture networks to be used in the flow and transport models. In our preliminary work we have been able to create such fractures in two space dimensions that respect the statistics presented in The American Association of Petroleum Geologists (see [Engelder 2009,;]). Thus we can provide a realization of a fracture network with known statistics that can be used in our combined continuum discrete-fracture mathematical model. *This, in combination with the methodology described in the previous paragraph, gives us the starting point to create the Latin Hypercube sampling strategy for our overall operational model.*

The second random field is that associated with the regional scale fractures. We will obtain this using a knowledge of the observed orientation of the fractures as presented in the literature (see [Engelder 2009,;]). We have made preliminary calculations that indicate that, at least in two dimensions, the required fracture network can be generated (see Figure 2). The uncertainty associated with hydraulic conductivity of this network we will obtain from the extensive literature on fluid flow properties in fractures and our preliminary studies have identified, for example, Balberg (1991), Niemi, (1997), Margolin (1998), Berkowitz (2002), and Cadini (2012).

Simulation: Given the random field, the next challenge is the creation of realizations that can be used in our continuum-based flow and transport model. Our preliminary work indicates that we can employ a technique similar to that we have used in the past to generate hydraulic conductivity realizations for porous flow and transport problems. The approach we have used is based upon a variant of Latin Hypercube sampling that we have found is very efficient and robust Zhang and Pinder (2000)

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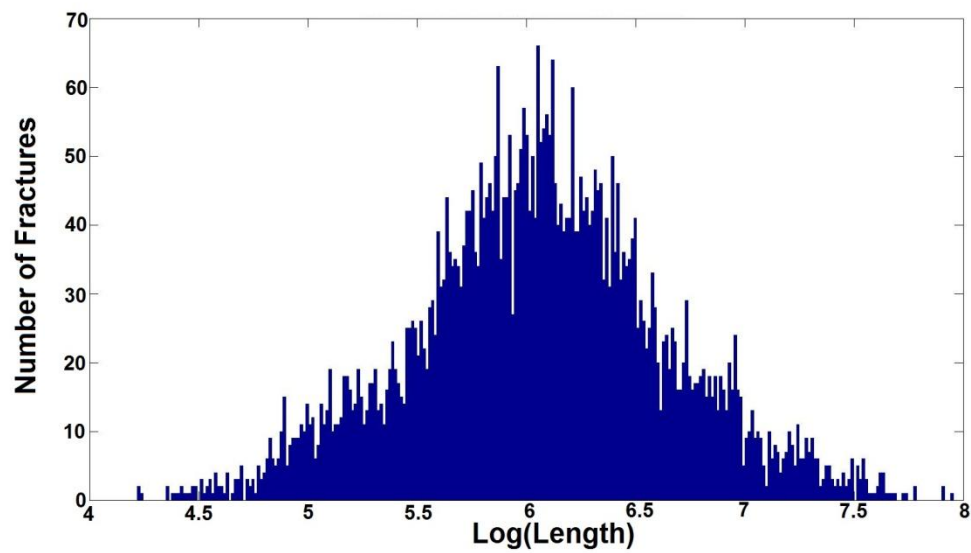
Results

The generation of preliminary realizations for random fields for the near-field and far-field fractures has been achieved. Flow and transport for selected test problems has also been realized as is evident in Figures 3, 4, 5, and 6. While these figures are not meant to represent any real-world situation, they do show that transport in fractured systems is feasible. Because, to be utilized, the risk algorithm requires multiple realizations of the above-mentioned random fields and such calculations have not yet been made, no risk results have been provided for this abstract.

Figures 3, 4, 5, and 6 all depict flow regimes which are from left to right with constant pressure boundary conditions on either end. The figures have not yet reached steady state. Figure 4 has the contaminant source between a set of fractures within the much less permeable rock matrix. Transport and flow are modeled after the pressure has reached the distribution seen in Figure 3. The two models are run on the same time scale with the same parameters for each run. Concentration travels very quickly through fractures but slowly through the rock matrix. Figure 6 shows how much more the contamination has traveled when the source intersects a fracture. It is important to note that contamination also reaches the right edge of figure 4, but not in large quantities, the contamination disperses through the rock matrix until it intersects the fracture and then is carried immediately away. The rate of mass transport into the fracture from the rock matrix is not at a sufficient rate to allow for any buildup within the fracture.
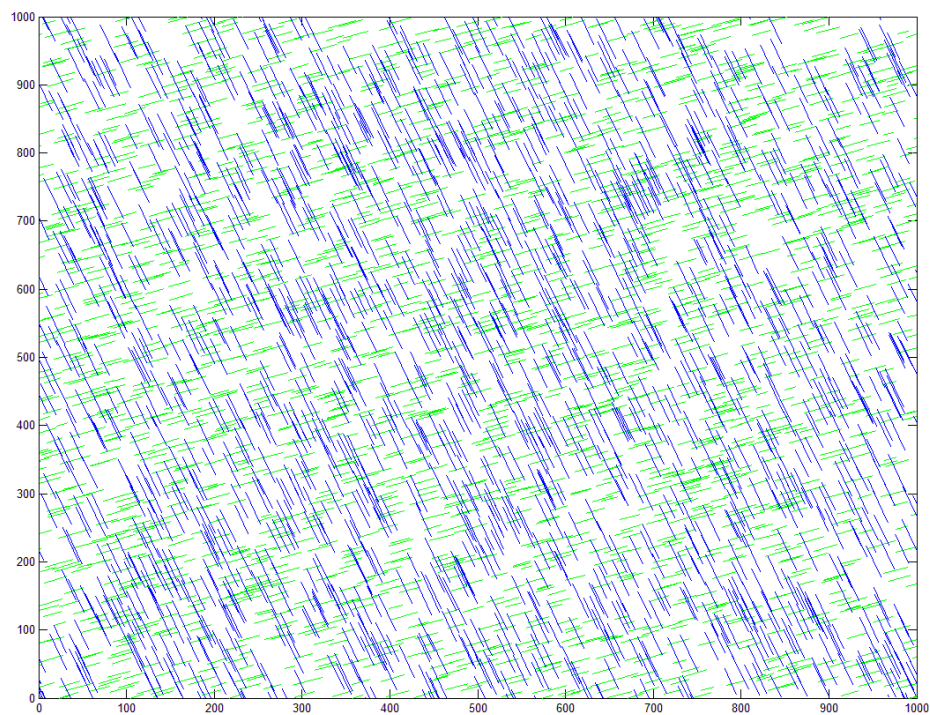
This model shows that the locations of fractures relative to concentration sources play a large impact in the flow of contaminants and the timescales on which they move. In both models contamination reaches the right boundary, the concentration is much greater.
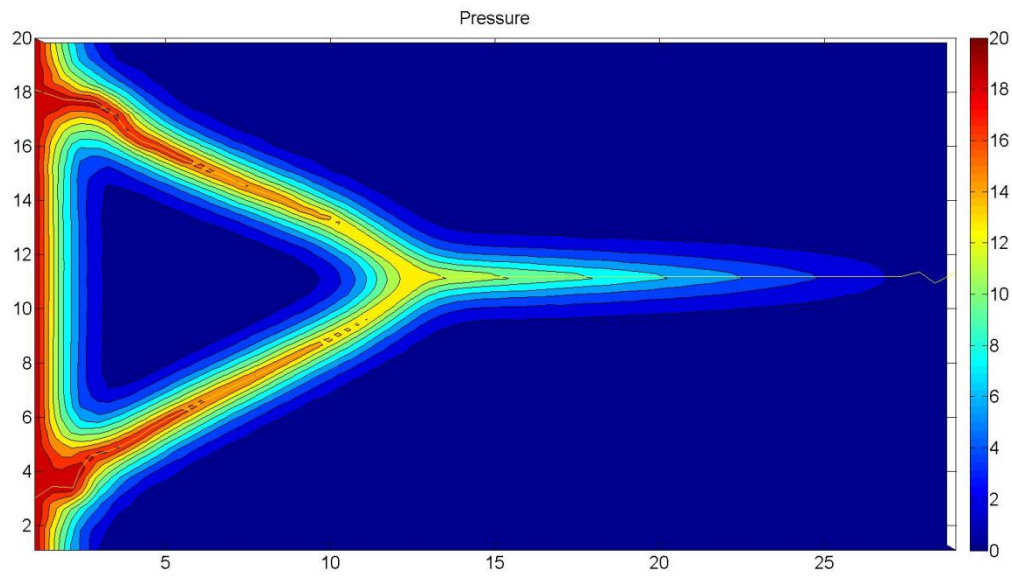
Conclusions

The assessment of the risk of potable aquifer contamination by fracking fluids over very long time frames can be determined using stochastic models wherein the hydraulic conductivity of both near-field and far-field fractures can be represented as random fields. To date we have preliminary calculations to suggest that the required random fields can be realized and mathematical models capable of representing flow and transport in one realization of a random field can be generated.
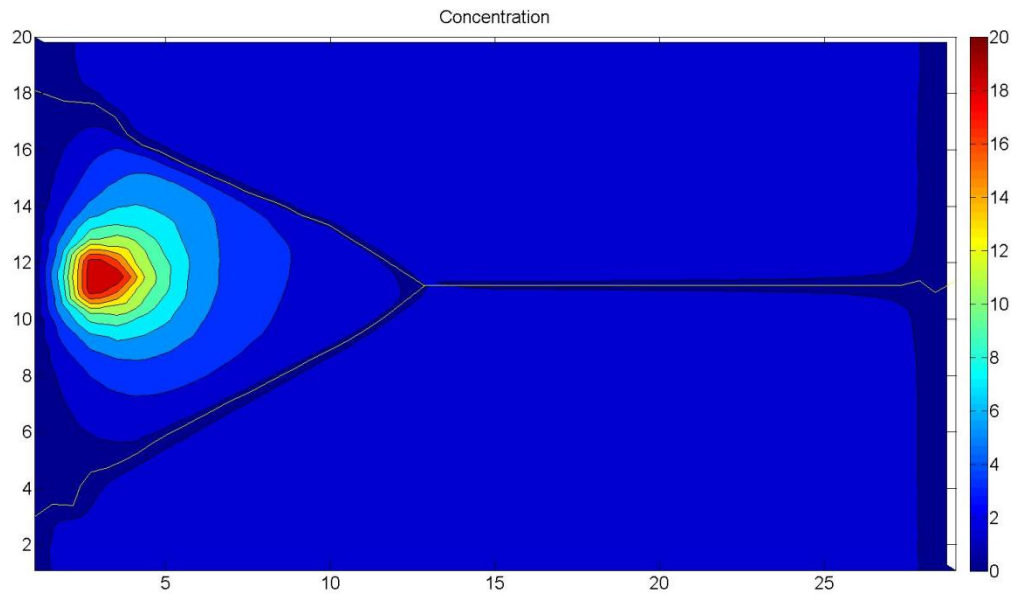
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Figure 1. Distribution of the log of fracture lengths from 5,000 observed hydraulic fractures in Barnet, Eagle Ford, Marcellus, Niobrara, and Woodford shales.
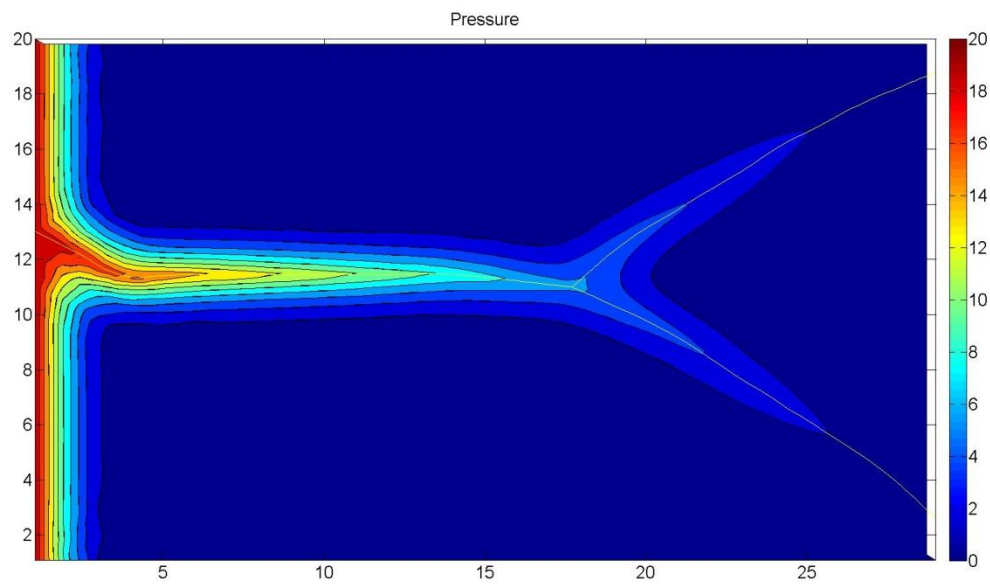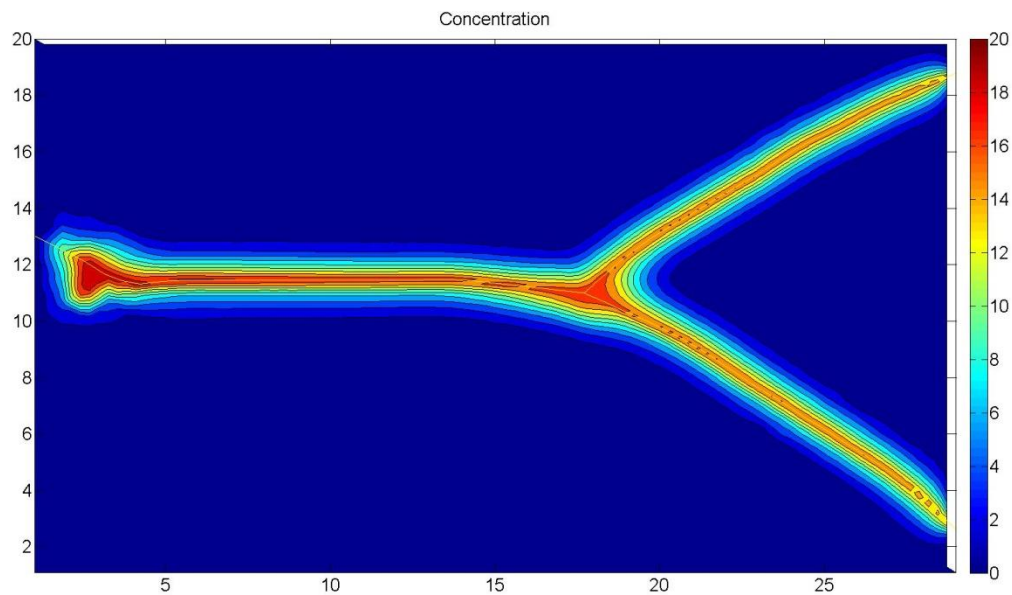

Figure 2. Generated fracture network.

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Figure 3. Pressure distribution in fractured porous medium.

Figure 4. Concentration distribution when fracture does not intersect source.

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Figure 5. Pressure distribution in fractured porous medium.

Figure 64. Concentration distribution when fracture intersects source.

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A Fully-Coupled, Fully-Implicit Parallel Solution Approach for Nonisothermal Multiphase Multicomponent Reactive Transport in Deforming Fractured Porous Media

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Introduction

High-fidelity simulation of nonisothermal, multiphase, multicomponent reactive transport coupled with geomechanics, often referred as coupled thermo-hydro-mechanical-chemical (THMC) processes in the subsurface community, at scales relevant for evaluating the impacts of hydraulic fracturing on drinking water resources, typically requires solving problems with a large number of unknowns. This is particularly challenging when systems of governing partial differential algebraic equations (PDAEs) are highly nonlinear and tightly coupled due to the complex interactions among processes. For example, thermoporoelastic effects could strongly alter formation permeability. Mineral precipitation and dissolution could also significantly alter porosity and permeability. In the subsurface reactive transport community, three major solution approaches that differ in coupling transport and reaction processes ([1, 2]) are available: (1) the global implicit approach (GIA), which solves all governing PDAES simultaneously at each time step using various forms of Newton's method, (2) the sequential iteration approach (SIA), which subdivides the reactive transport problem into transport and reaction subproblems, solves them sequentially, and then iterates until convergence criteria are met, and (3) the sequential non-iteration approach (SNIA), which solves the transport and reaction problems sequentially without iteration, often referred as operator-splitting approach. The GIA was considered to be too CPU time and memory intensive [1] or to be computationally inefficient [2], thus, in widely used reactive transport simulators, e.g. TOUGHREACT [3], the operator-splitting approach has been most often adopted due to its simplicity of implementation and low computational resource requirement. An important advantage of the operator-splitting solution strategy is the convenience of coupling different existing codes that handle different aspects of coupled multiphysics problems. The same operator-splitting solution strategy has also been widely used to solve coupled THMC problems. For example, one recent geothermal example of the SNIA approach is presented by Rutquist et al. [4], in which the widely used flow and heat transport simulator TOUGH2 [5] is coupled to the commercial rock mechanics simulator FLAC [6] via input files. During each time step, TOUGH2 and FLAC run sequentially with the output from one code being used as input to the other. However, under the situations when strong thermoporoelasticty coupling exists and geochemical reactions strongly alter porosity/permeability, operator-splitting approach could lead to significant splitting errors and requires very small time steps to maintain solution accuracy and convergence [1]. When SIA approach is applied, it often fails to converge for tightly coupled multiphysics problems even with small time steps.

In recent decades, advances in computing hardware and computational algorithms such as strongly convergent nonlinear solvers (including Jacobian-Free-Newton-Krylov (JFNK) method [7]) and efficient linear solvers such as Generalized Minimum Residual (GMRES) [8], have made the fully coupled GIA approach attractive for solving tightly coupled systems.

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In this short note, we present a fully-coupled fully-implicit numerical solution approach that is used for to develop multiphysics simulators for reactive transport, hydro-thermo-mechanical (THM) problems, and THMC problems. The simulators are developed upon a Multiphysics Object Oriented Simulation Environment (MOOSE) computing framework developed at INL. The use of state-of-the-art nonlinear solver such as preconditioned JFNK method enables an efficient solve of coupled nonlinear PDAEs simultaneously without explicitly computing and storing the Jacobian. The preconditioned JFNK solution approach will be briefly explained in Section 2. The numerical performance and parallel scalability of the simulator are also illustrated. Three synthetic THMC examples that involve various processes are presented and briefly discussed. These example THMC problems demonstrate the potential applicability of the fully-coupled, fully-implicit solution strategy for assessing impacts of hydraulic fracturing to aquifers.

Preconditioned Jacobian-Free Newton-Krylov Method

Newton's method for solving coupled nonlinear PDEs typically begins with a discrete form of the governing PDEs and casts it into a general residual function

$$\mathbf{F(u)=M(u)\dot{u}+K(u)u-R(u)=0} \tag{1}$$

where $\mathbf{u}$ is the solution vector, $\mathbf{M}$ is the mass accumulation matrix , $\mathbf{K}$ is the stiffness matrix (often with element values as functions of $\mathbf{u}$) and $\mathbf{R}$ is the source term vector. $\mathbf{F(u)}:\mathbf{R}^1 \rightarrow \mathbf{R}^N$ is the system nonlinear residual vector, where N is the number of unknowns. The traditional Newton iterative method typically requires the full Jacobian matrix

$$\mathbf{J(u)} = \frac{\partial \mathbf{F(u)}}{\partial \mathbf{u}} \tag{2}$$

to update the solution vector by solving the linearized system

$$\mathbf{J(u}^{(k)})\delta\mathbf{u}^{(k)} = -\mathbf{F(u}^{(k)}) \tag{3}$$

followed by an update of the solution state $\mathbf{u}^{(k+1)} = \mathbf{u}^{(k)} + \delta\mathbf{u}^{(k)}$. In this process, forming each element of $\mathbf{J}$ can be difficult, time consuming and error-prone. Storing full $\mathbf{J}$ matrix also requires large amount of memory.

To avoid such hurdles, by taking the advantage of the fact that a Krylov solver dose not require full $\mathbf{J}$ in solving Eq. (3), the JFNK solution approach is adopted in our solution approach. Staring with an initial guess of $(\delta\mathbf{u})_0$, initial linear residual is formed according to

$$\mathbf{r_0} = -\mathbf{F}-\mathbf{J} \times (\delta\mathbf{u})_0 \tag{4}$$

Then the approximate solution of Eq. (3) at the lth Krylov iteration is constructed from a linear combination of the Krylov vectors $\mathbf{r_0},\mathbf{Jr_0},(\mathbf{J})^2\mathbf{r_0},\cdots,(\mathbf{J})^{l-1}\mathbf{r_0}$ constructed from the previous $l-1$ Krylov iterations,

$$(\delta\mathbf{u})_l = (\delta\mathbf{u})_0 + \sum_{j=0}^{l-1}\alpha_j(\mathbf{J})^j\mathbf{r_0} \tag{5}$$

where the scalar coefficient α_j is part of the Krylov iteration[5]. Eq. (5) shows that the Krylov method for solving Eq. (3) only requires the product of the Jacobian matrix $\mathbf{J}$ and Krylov vector $\mathbf{v}$, not the Jacobian itself. Specifically, to evaluate this matrix-vector product, $\mathbf{J(u}^{(k)})\mathbf{v}$, a finite difference approach, Eq. 6, can be used[4], where ε is a very small perturbation.

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$$\mathbf{J}(\mathbf{u}^{(k)})\mathbf{v} \approx \frac{\mathbf{F}\ \mathbf{u}^{(k)} + \varepsilon\mathbf{v}\ \text{-}\mathbf{F}\ \mathbf{u}^{(k)}}{\varepsilon} \tag{6}$$

The use of preconditioning in solving the linear system of Eq. (3) is to efficiently cluster eigenvalues of the iteration matrix, which in turn will reduce the number of Krylov iterations required for convergence. When applying the right preconditioning to Eq. 3, one solves

$$\mathbf{J}(\mathbf{u}^{(k)})\mathbf{P}^{\text{-}1}\quad \mathbf{P}\delta\mathbf{u}^{(k)}\ = -\mathbf{F}(\mathbf{u}^{(k)}) \tag{7}$$

where $\mathbf{P}$ is a linear operator and symbolically represents the preconditioning process. $\mathbf{P}$ is chosen in the manner such that it is a suitable approximation to the Jacobian matrix. The right preconditioned version of the JFNK matrix-vector product approximation of Eq. 6 becomes

$$\mathbf{J}(\mathbf{u}^{k})\mathbf{P}^{\text{-}1}\quad \mathbf{v} \approx \frac{\mathbf{F}\ \mathbf{u}^{k}\ + \varepsilon\mathbf{P}^{-1}\mathbf{v}\ -\mathbf{F}\ \mathbf{u}^{k}}{\varepsilon} \tag{8}$$

Thus the preconditioned JFNK process is implemented in two steps: 1) Solve $\mathbf{Py} = \mathbf{v}$ for $\mathbf{y}$; 2) Perform matrix-vector product approximation using Eq. (8); and repeat steps 1 and 2 until the Krylov iteration converges.

In a physics-based preconditioning approach, the preconditioner $\mathbf{P}$ is not obtained by algebraically manipulating the Jacobian matrix; rather, approximations are made to the original differential system to form an approximate Jacobian only for preconditioning purpose. We illustrate a general implementation of the physics-based preconditioner below.

The pressure-temperature formulation for flow and heat transfer is shown in Eq. 9 and 10:

$$\frac{\partial(n r)}{\partial t} - \nabla \cdot \left[t r \cdot (\nabla p - r g \nabla z) \right] - Q = 0 \tag{9}$$

$$\frac{\partial[n r c_w + ((1 - n) r_r c_r)]T}{\partial t} - \nabla \cdot (K_m \nabla T) + r c_w q \nabla T - Q = 0 \tag{10}$$

Following Lichtner [10], the general PDEs that govern reactive transport read as

$$\frac{\partial}{\partial t} q(c_l + \underbrace{\sum_{m=1}^{N_s} n_{lm} K_{eq,m} \prod_{n=1}^{N_c} c_n^{n_{nm}}}_{\text{equilibrium reaction}}) + \underbrace{(-\nabla q\mathbf{D}\cdot\nabla + \mathbf{q}\cdot\nabla)(c_l + \sum_{m=1}^{N_s^M} n_{lm} K_{eq,m} \prod_{n=1}^{N_c} c_n^{n_{nm}})}_{\text{transport}} - \underbrace{\sum_{k=1}^{N_k} q b_{lk} R_k (c_1,\cdots,c_{N_c})}_{\text{kinetic reaction}} = 0 \tag{11}$$

$$l = 1,2,\cdots N_c$$

Assuming linear elasticity for stress-strain relationship and adopting finite small strain formulation, we get the governing equation for displacement:

$$r\frac{\partial^2 u}{\partial t^2} - B^T DB u - r g - a\nabla p - bK\nabla T = 0 \tag{12}$$

where $B = \begin{pmatrix} \P_x & 0 & 0 \\ 0 & \P_y & 0 \\ 0 & 0 & \P_z \\ \P_y & \P_x & 0 \\ 0 & \P_z & \P_y \\ \P_z & 0 & \P_x \end{pmatrix}$, $D = c_1\begin{pmatrix} 1 & c_2 & c_2 & 0 & 0 & 0 \\ c_2 & 1 & c_2 & 0 & 0 & 0 \\ c_2 & c_2 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & c_3 & 0 & 0 \\ 0 & 0 & 0 & 0 & c_3 & 0 \\ 0 & 0 & 0 & 0 & 0 & c_3 \end{pmatrix}$, $c_1 = \frac{E(1 - v)}{(1 + v)(1 - v)}$,

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$$c_2 = \frac{v}{(1-v)}, \quad \text{and } c_3 = \frac{1-2v}{2(1-v)}.$$

Detailed notations can be found in our related publications [11, 12].

With the set of governing equations of Eq. 9, 10, 11, and 12, we could form weak formulations of them using Galerkin finite element method. Then one can cast the weak form into a residual function and take the derivative with respect to the primary variables of pressure, temperature, primary species concentrations c_l, and displacement to obtain approximate Jacobian, which could be used as the preconditioning matrix $\mathbf{P}$. It can be further simplified to have only the diagonal blocks (D) as

$$\mathbf{P} \approx \begin{bmatrix} \mathbf{J}_{11} & \mathbf{0} & \cdots & \mathbf{0} \\ \mathbf{0} & \mathbf{J}_{22} & \cdots & \mathbf{0} \\ \vdots & \vdots & \ddots & \vdots \\ \mathbf{0} & \mathbf{0} & \cdots & \mathbf{J}_{NN} \end{bmatrix} \tag{13}$$

In our implementation of preconditioned JFNK, the full preconditioning matrix is never actually formed. We have routinely used only the diagonal blocks of Jacobian matrix as the preconditioning matrix and achieved satisfying computational performance.

Parallel Computational Performance

In our code, we implemented the preconditioned JFNK approach described in the previous section. Figure 1(a) shows a strong scaling test of the simulator ranging from 640 to 10,240 processors. The result indicates a close-to-ideal parallel scaling performance. In Figure 1(b), it is shown that the adaptive mesh refinement/coarsening capability available in the simulator greatly reduces the computational cost by reducing the number of degree of freedoms (DOFs) while still maintains solution accuracy.

(a)   (b)
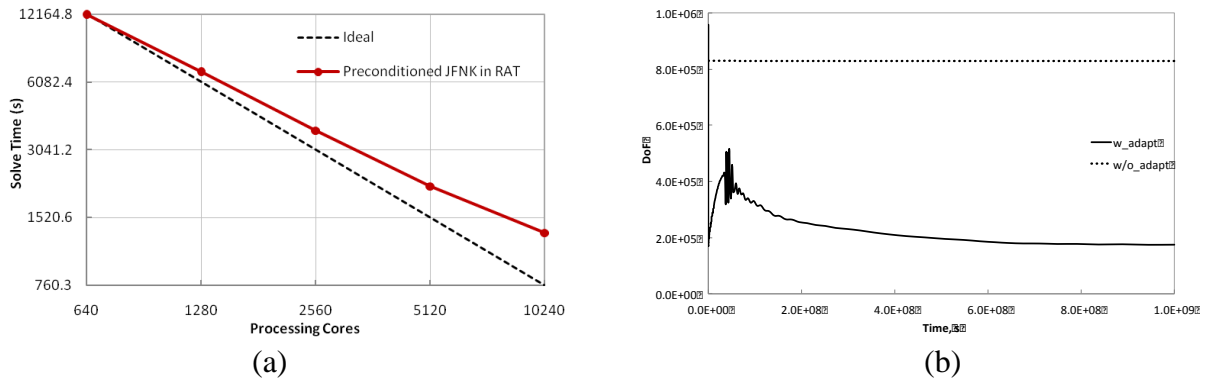
Figure 1. Numerical efficiency and parallel performance: (a) strong scaling on a distributed memory parallel system, and (b) comparison of numbers of DoF solved with or without mesh adaptivity.

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Example THMC Problems

In this section, we present three synthetic examples of coupled THMC problems in order to demonstrate the capabilities of the simulator and its potential to be applied for assessing impacts of hydraulic fracturing on groundwater.

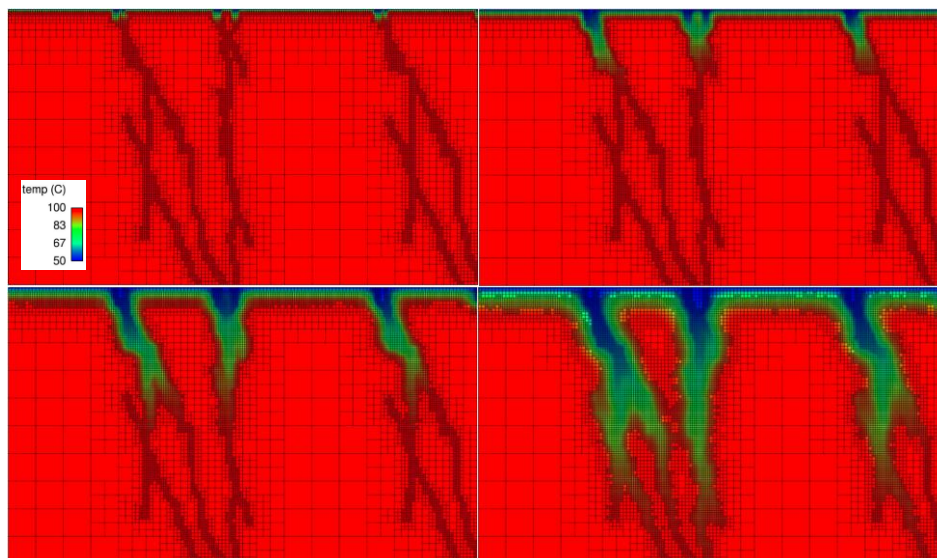### *Coupled THM simulation that utilizes adaptive meshing*

In the first example, a lower temperature fluid is allowed to flow through a series of intersecting, aperture-varying fractures contained within a higher temperature domain. In this case, a predefined fracture distribution was provided and initial mesh adaptivity was utilized to accurately capture the discrete fractures. During simulation time, the adaptive mesh refinement/coarsening was further utilized by refining in regions of high pressure/temperature gradient jumps. This allowed for greater detail to be captured in areas of interest, like rapid flow through the individual fractures, while saving significant computational costs in areas of little activity, like that of the far field rock domain.

The two-dimensional domain is 170m by 100m. The initial domain temperature is 100°C and a Dirichlet boundary condition of 50°C is applied to the top of the domain. A relatively small pressure gradient is applied across the domain to create fluid flow through the fractures in addition to heat transfer. Permeability is assigned to be 1.0E-14 m^2 to the surrounding rock matrix and 1.0E-11 m^2 to the fractures. A schematic of the conceptual model is shown in Figure 2.
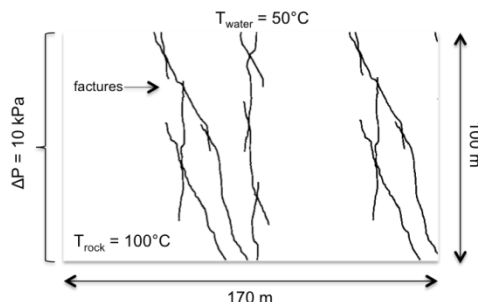
Figure 2. Schematic of example 1 model setup

Figure 3 shows the temperature field evolution with an overlay of the mesh used at time steps. Note that the upper left panel shows the initial state where mesh is refined around the fractures and the remaining figures show the propagation of temperature front through the fractures with adaptive meshes.

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Figure 3. Adaptive mesh overlaid upon temperature field in simulation of fluid flow through multiple fractures

Coupled THMC simulation in a heterogeneous medium

In the second example, we inject a solution that is undersaturated with respect to the initial mineral phase in the domain at a lower temperature than the initial reservoir temperature. Mineral dissolution and themoelasticity cause changes in porosity and permeability, thus affecting the fluid flow and transport processes, which in turn induces changes in the stress and strain fields. The stress/strain fields change due to both changes in the pressure distribution and the temperature distribution (a classical thermoporoelasticity problem).

The two-dimensional domain is 150m by 75m. A stochastic permeability field is generated for this domain using Geostatistical Software Library (GSLIB) [12] with a longer correlation length along x direction than y direction (hence the layering), a mean value of 1.34E-11 m^2 and a range between 9.53E-13 and 1.14E-10 m^2. A schematic of the conceptual model is shown in Figure 4.
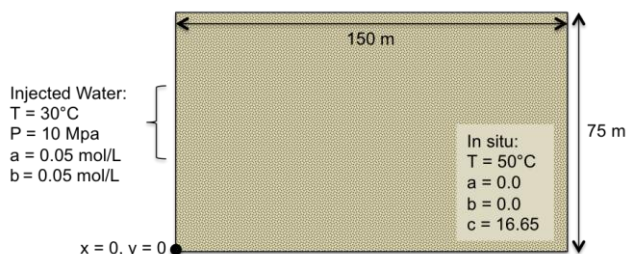

Figure 4.   Schematic of example 2 model setup.

Figure 5 shows the simulated spatial distributions of major solution variables at an earlier and a later time, respectively. At the earlier time (Figure 5(a)), pressure is distributed relatively uniformly along the x direction with perturbations from the heterogeneous permeability shown at the lower right corner. Solid mineral phase is initially uniformly distribution throughout the domain at a concentration of 16.65 mol/L, which is equivalent to 20% volume fraction.

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Dissolution takes place when an undersaturated solution is injected. The dissolution rate follows the rate expression based on transition state theory by Lasaga [13]: $R_c = -k_{ref} \left[1 - C_a \times C_b / K_{eq} \right]$.

As the mineral is dissolved, local porosity increases based on the molar volume of the mineral c (40.03 m^3/mol). Subsequently, permeability changes according to the Carman-Kozeny relationship:

$$k = k_i * \left(n/n_i \right)^3 * \left(1 - n_i \right)^2 / \left(1 - n \right)^2 \qquad (14)$$

(a)

(b)
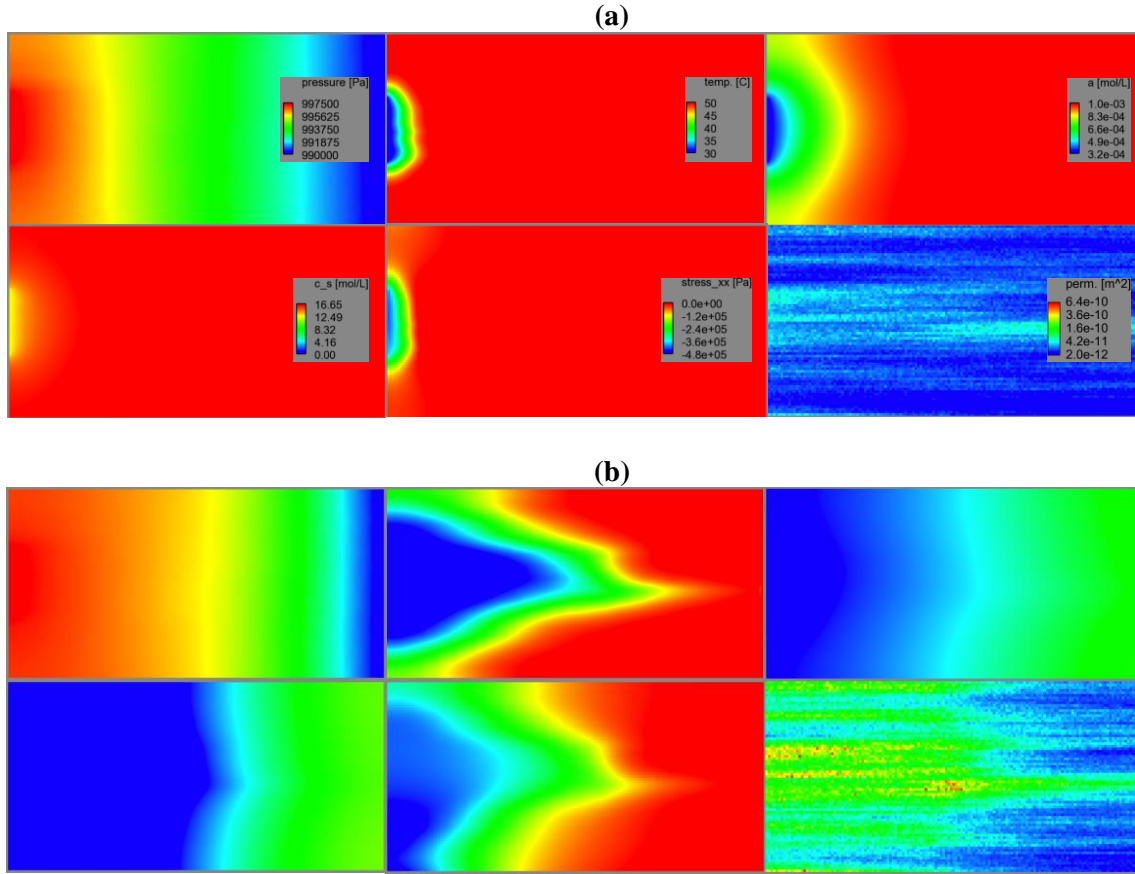
Figure 5. Spatial distribution of pressure, temperature, species a concentration, mineral c concentration, xx component of stress, and permeability for an earlier time (a) and later time (b). The scales apply to both sets of figures.

The injected solution has a temperature 20°C lower than the initial uniform temperature in the field. The advective flow transports heat by convection in addition to conduction through the rock. However, with a relatively high flow velocity (average around 1.5E-4 m/s), convection is a more significant mechanism of heat transport. This becomes evident with the observation that the heat transport is fastest along the high permeability layers where the flow velocity is the highest. Since the left boundary of the domain is fixed for displacement, the xx component of stress is all tension as a combined effect of pressure and temperature. But it is evident that the effect of temperature on the stress distribution is more important since the distribution of stress closely follows the pattern of that of temperature. This is a strongly nonlinear problem: the chemical reactions significantly increase porosity and permeability, which facilitates transport of colder

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fluid, which in turn cause significant changes of stress state due to porothermoelastic coupling. The preconditioned JFNK approach is able to solve this tightly coupled THMC problem in a fully-implicit, fully-coupled manner with relatively large time steps.
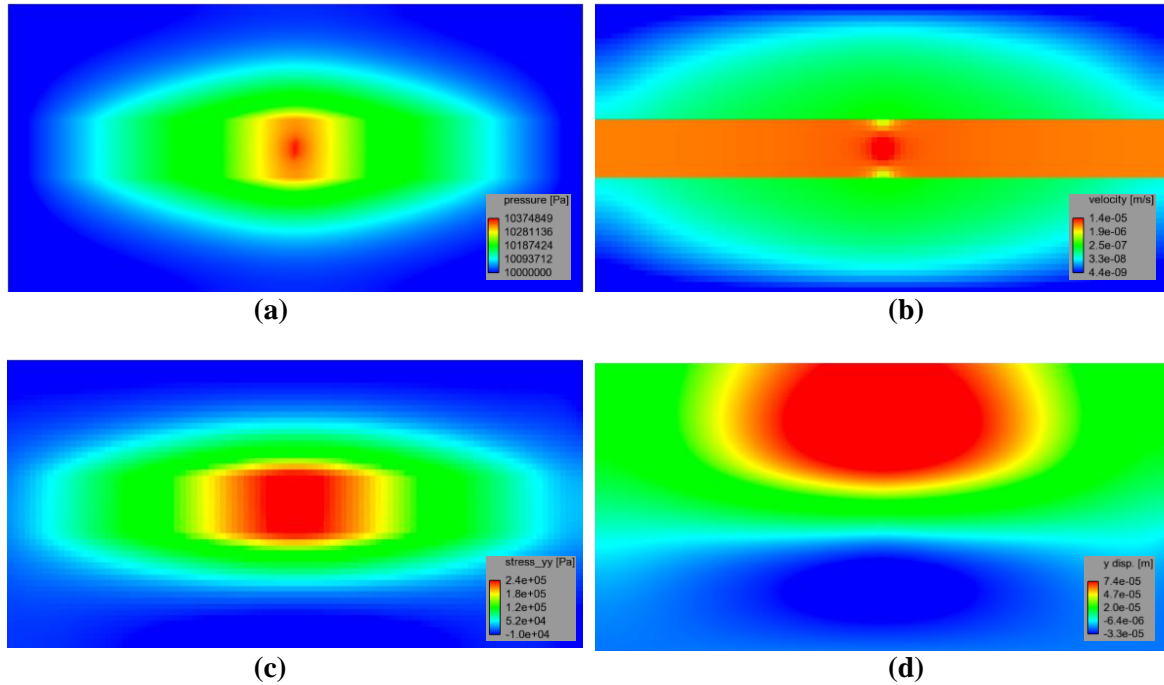
Injection at high pressure and mechanical responses in a fractured zone

The third case examines the mechanical response to a high pressure fluid injection within a fractured high-permeability layer bounded by low permeability formations as shown in Figure 6. The domain size is 100 m x 50 m, water is injected at high pressure gradient (~7500 Pa/m) into a relatively high permeability zone with a permeability 2 orders of magnitude higher than the bounding layers above and below. An overburden pressure of 25MPa is applied at the top of model domain.
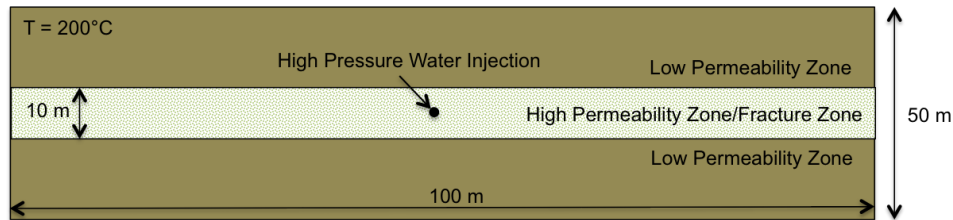
Figure 6. Schematic of example 3 model setup.

Figure 7(a) shows the pressure distribution at the end of the simulation time. It is evident that along the high permeability layer the pressure gradient is much smaller than that across the layer interfaces. As shown in Figure 7(b), the flow velocity within the fractured zone is orders of magnitude higher than that across the interfaces into the lower permeability bounding layers. The high fluid injection pressure around the injection well will counter balance the overburden stress, thus the stress state around the injection well will become less compressive, which can be seen in Figure 7(c). Figure 7(d) shows the displacement of the rock along the vertical direction in response to fluid injection. Unlike the conventional THM simulator, our JFNK simulator solves the flow equation and momentum equations for rock deformation simultaneously with relatively large time steps and stills maintains good convergence behaviors.

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Figure 7. Distribution of calcium carbonate precipitates along the column at 1, 2, 4 and 8 pore volumes of injection for different combination of flow rate and enzyme concentration.

Conclusions

We developed a parallel fully-coupled, fully-implicit simulator for coupled THMC processes in the subsurface based on a preconditioned JFNK nonlinear solution approach. The new THMC simulator provides a number of advanced computing capabilities such as (1) massive parallelism and scalability, (2) quadratic nonlinear convergence even for large, extremely nonlinear problems and (3) adaptive mesh refinement/coarsening that enhances the efficiency of the solution approach. The examples presented in this short note demonstrate the potential applicability of such fully-coupled, fully-implicit approach for modeling large THMC problems such as the one of assessing impacts of hydraulic fracturing to aquifers.

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Modeling Near Wellbore Leakage Pathways in Shale Gas Wells: Investigating Short and Long Term Wellbore Integrity

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The rapid extraction of shale gas resources in the past years has dramatically affected US Energy markets. Shale gas as an alternative for oil and coal has brought several advantages and, most notably, has decreased the carbon dioxide emission and helped the nation's energy independence policy. However, the development of shale gas has raised several environmental issues which have intensified the general public's concern about reliability of applied technology. These concerns have become more severe after the BP Macondo incident in 2010. Among these concerns, hydraulic fracturing and failure in the wellbore construction have been reported excessively for imposing risks of natural gas migration and drinking water pollution.
Well construction practices are very critical affecting short and long terms wellbore integrity. A well can keep its integrity in short term, however, it can lose its integrity in log term due to different materials degradation, change in stresses because of depletion and/or cyclic pressure and thermal loads. The followings are the main aspects that need to be addressed:

1. Short and Long terms well integrity: What are the potential leakages in the near-wellbore regarding all possible scenarios?
2. How efficient are the current well construction procedures (standards) to prevent gas migration to the surface drinking water resources in short and long term?
3. How to identify the wells with construction problems that have been already drilled/or abandoned in the past? And what kind of intervention/remediation they will require?
4. Wellbore integrity in injection wells (for waste water disposal), re-fracturing occasions and deep gas wells: How the injection, thermal loads and re-fracturing will affect short and long terms well integrity?

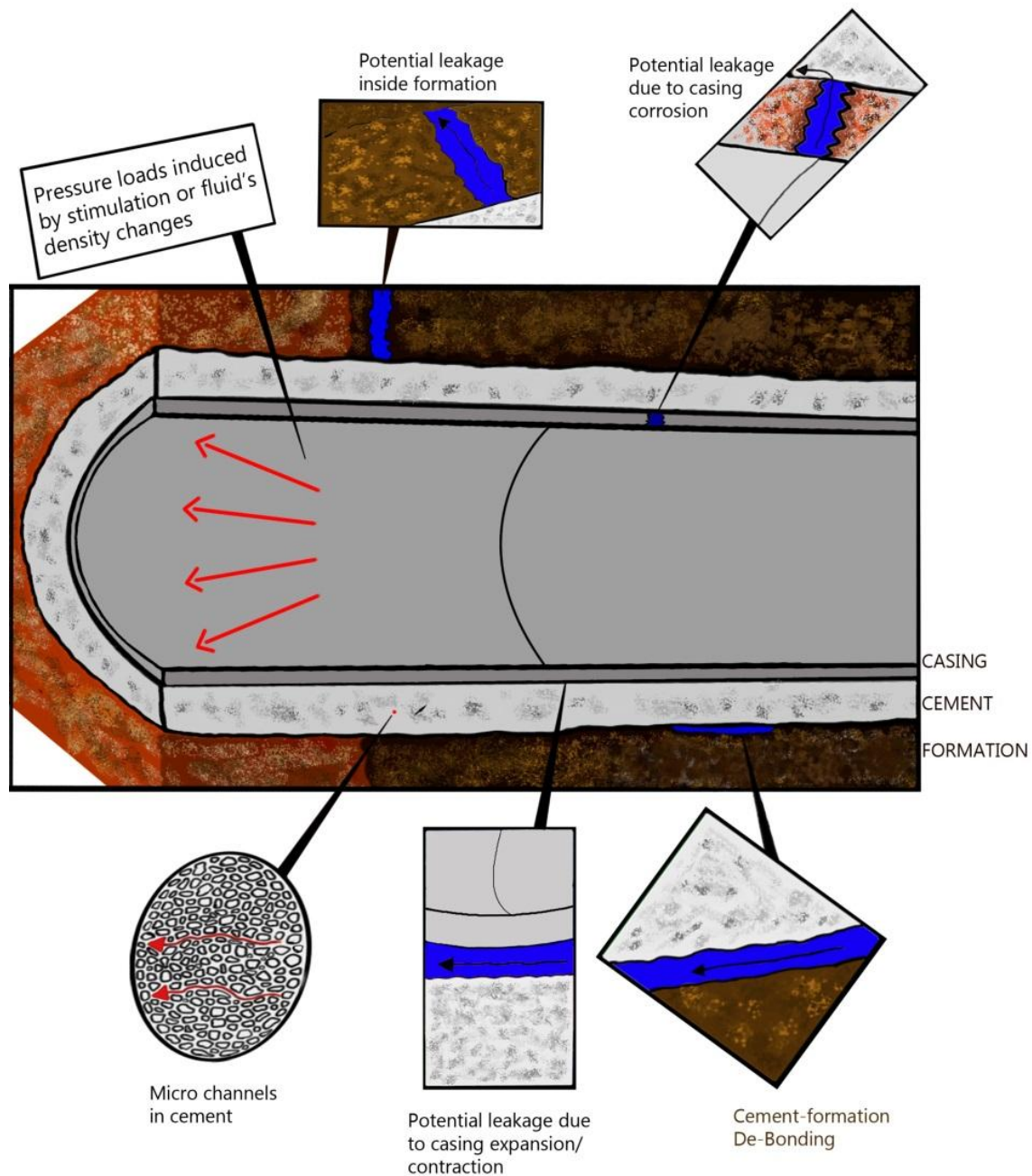**Possible Leakage Pathways in Near Wellbore**

Generally a wellbore can fail due to several reasons such as poor cementing operation and/or failures due to mechanical and thermal loads. These loads can create tensile and shear failures in boundaries of the casing-cement-formation or inside each of these elements. Changing fluids density for completion and stimulation can also induce mechanical loads inside well which need to be considered for integrity evaluation. Changes in temperature due to cooling or heating can impose thermal stresses which may trigger long term well integrity. Furthermore, corrosion in the casing or chemical reactions of the cement can also create near wellbore leakage paths (Figure 1). An integrated numerical/experimental study has been initiated to investigate the near wellbore leakage pathways in shale gas wells. The main objective of study is to explore various leakage scenarios in which well integrity can be compromised. Results of numerical models will indicate integrity problems due to inappropriate well construction design or failure in different

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elements such as rock, cement and casing due to loads applied through the well's life. Laboratory experiments are also designed to extract rock and cement properties such as Young Modulus, Poisson's ratio, permeability, hydration and heat transfer related properties. A comprehensive database is under construction for different shale gas plays based on available information through State and some Industry agencies (Figure 2).
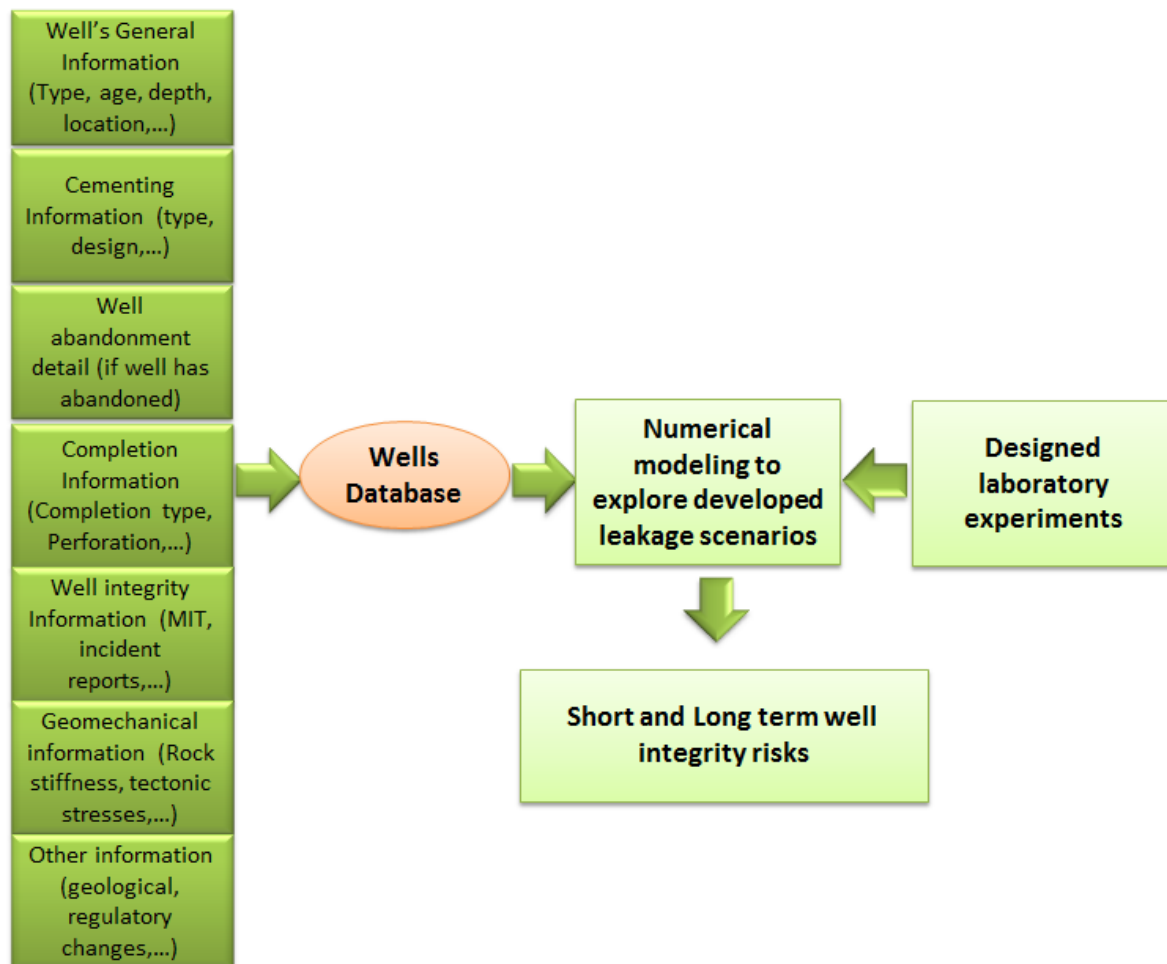
Novel three-dimensional finite-element models have been built for numerical analysis. The models have features to include geomechanical properties, thermal and poro-elastic properties of the cement and rock. Several stages of the well's life will be simulated including cementing process, completion, fracturing and final abandonment. In addition parallel leakage scenarios have been simulated for abandoned wells.

A preliminary study form one of the wells currently drilled in Haynesville shale revealed interesting results regarding long term well integrity concerns for this well. A recently drilled and completed well was selected in this field to investigate potential short and long term wellbore integrity risks. The well TVD is around 11,200 ft depth with approximately 3,000 ft lateral section. All the available Mechanical Integrity Tests including pressure tests, CBL/SBL and other petrophysical logs were analyzed for evaluating wellbore integrity and were fed as inputs in numerical models.

Simulations were also carried out for this well regarding integrity risks after the well completed and one possible re-fracturing scenario in future. All stages of drilling, casing, cementing, completion and stimulation were accomplished with evaluating wellbore integrity at each step. Simulations results indicate risk of de-bonding and generation of tensile fractures due to possible mechanical loads induced by re-fracturing loads.

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Figure 1. Potential leakage pathways created in near wellbore due to poor cement job or failure initiated by additional loads induced through the well's life such as stimulation or change in the pressure inside the wellbore as well as possible thermal loads.

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Figure 2. A comprehensive database is under construction to study wellbore integrity risks in short and long term