Better well integrity

US-Norway Technology Partnership Conference, Minimising Oil Spills and Discharges to Sea
Ken Feather – VP Marketing & Sales, Well services
Houston, 30 March 2011

Archer
The well company

Agenda

Archer

1. Industry challenge
2. Life-of-well integrity solutions
3. Overview of Archer
4. Questions

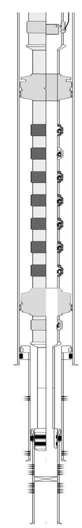
Industry challenge

A typical well…

> 2000 components

harsh conditions

wells fail



A global challenge

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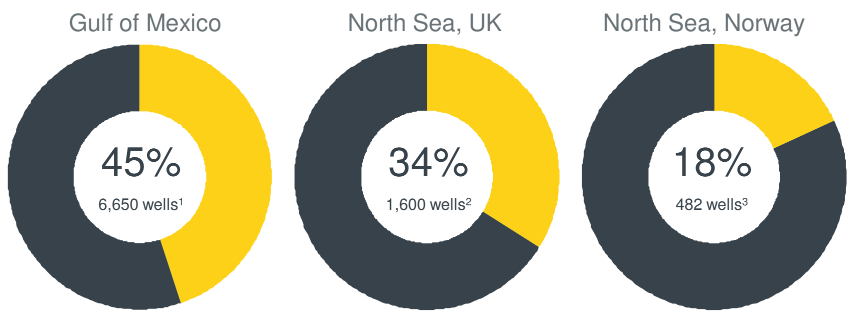
% of wells with integrity issues



1 **US Minerals Management Service survey, 2004**. Reported 6,650 out of 14,927 active wells had sustained annular pressure in deepwater and shelf GOM.

2 **SPE forum North Sea Well Integrity Challenges, 2009**. Approx. 100 participants indicated no. of wells with at least one anomaly. Average 1,600 out of 4,700 active wells.

3 **Norwegian Petroleum Safety Authority, Well Integrity study, 2006**. Study sampled 406 of 2,682 wells. 18% of wells had well integrity failures or issues. 7% completely shut in owing to integrity issues

Failures affecting well integrity & performance

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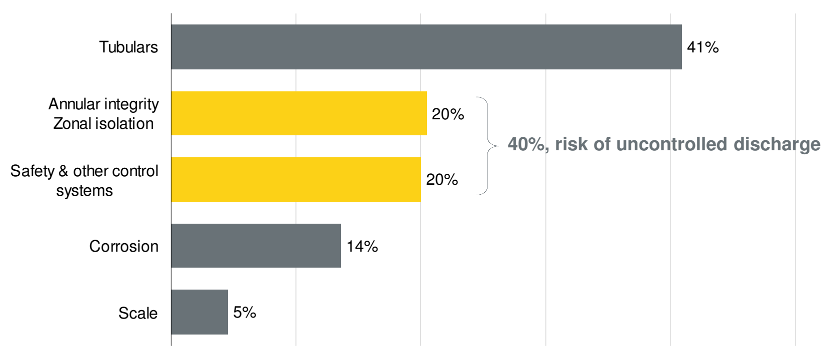
Integrity and performance failures



1 **OTM Consulting & Archer market survey 2010.** Data shows relative distribution failures affecting well performance encountered by survey participants. Based on global industry sample of 20 well performance experts.

The cost of well integrity failures

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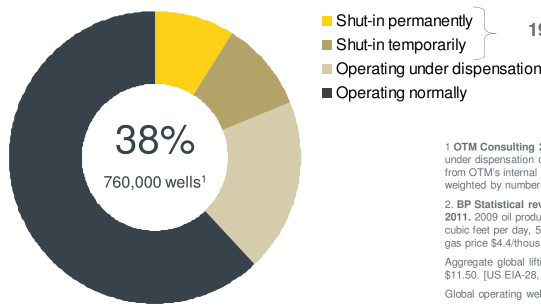
Global wells affected by integrity issues



19% shut-in, ~$1 billion/day lost [2]

1 **OTM Consulting 2009.** Calculated percentages of global wells (oil & gas) operating under dispensation or shut-in permanently or temporarily. Global averages developed from OTM's internal regional market models for all oil and gas wells. Issue fractions weighted by number of wells per region.

2. **BP Statistical review of world energy 2010; US EIA-28 2009; OTM Consulting 2011.** 2009 oil production 79,948 thousand bopd; 2009 gas production 284.5 billion cubic feet per day, 50,271 thousand boepd. Average 2009 oil price $61/bbl, average gas price $4.4/thousand cubic feet ~$25/boe. [BP 2010].

Aggregate global lifting costs (combined oil and gas calculated using $ per bbl or boe) $11.50. [US EIA-28, 2009]. Aggregate global revenue oil $49.5/bbl, gas $13.5/boe.

Global operating wells oil ~900,000; gas ~1,100,000 [OTM Consulting 2011]

Assume 19% of operating wells are shut-in due to integrity issues then production comes from oil 729,000 wells (average 110 bopd/well); gas 891,000 wells (average 56/boepd/well).

Assume that shut-in wells would produce same average per day then potential production oil is 110*171,000=18,810 thousand bopd; gas is 56*209,000 = 11,704 boepd.

Therefore lost revenue oil is 18,810*49.50 = $931 million/day; gas is 11,704*13.50 = $158 million/day. Total lost potential revenue is **$1,089 million/day**.

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Life-of well integrity solutions

Two main types of well integrity issue

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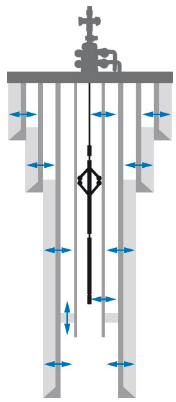
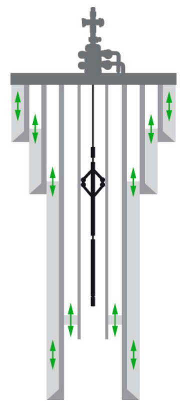


Leak flow

tubing, casing, valves, packers…



Annular flow

cement integrity, packers, plugs…

Life-of-well integrity solutions

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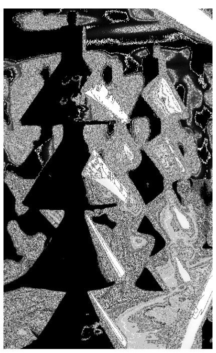


Cflex™

Annular seal integrity extends well life

VMB™ plug

Safe & secure "zero-bubble" well suspension

Point®

Bringing clarity to well integrity management

Performance eye

3D perspective on well performance

Well delivery ⟷ Well performance

Archer

Annular seal integrity & zonal isolation

Annular seal integrity

Archer

Cflex™

– From the specialists in well barrier technology
– Annular seal integrity with unique staged cementing capability

Key benefits

– Fullbore ID: No need to drill out
– Slimmer OD: Easier flowpath
– Any material: Inbuilt integrity
– V0 rated: Zero bubble
– Locks permanently: Security

Archer

Temporary or permanent well suspension

Safe & secure "zero-bubble" well suspension

Archer

VMB plug

- From the specialists in well barrier technology
- Safe & secure V0-rated well suspension plugs
- Precision engineered products take well integrity assurance to a new level
- Temporary or permanent well suspension

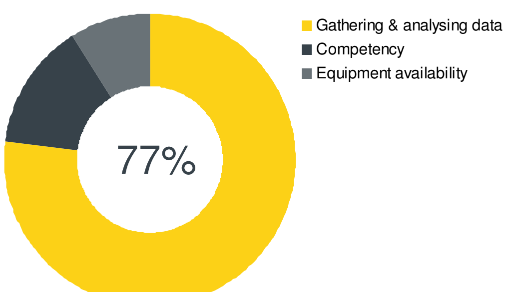
Key benefits

- Safety & security
- Efficiency, lower cost

Diagnosis

Dealing with well integrity issues

Integrity management challenges



1 **SPE North Sea Well integrity forum, Nov 2009 & Drilling Engineering Association (DEA) Europe, March 2010.** Data compares main challenges faced by operators in managing well performance. 100+ operator participants.

Bringing clarity to well integrity management

Archer

The Point™ system

- Unique technology reveals serious integrity failures rapidly and precisely
- Bringing clarity to well integrity management, improving well efficiency and extending well life

Key benefits

- Fast, precise location of failures
- Confidently select and target correct remediation

Where is the leak?

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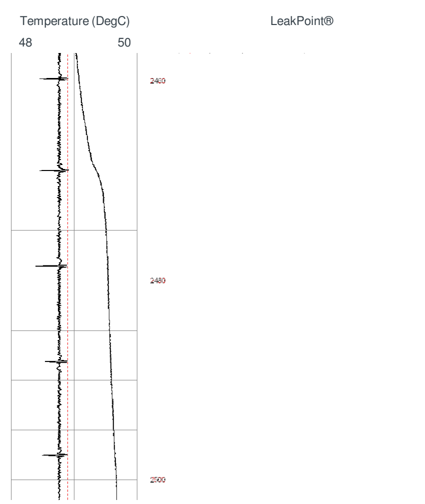
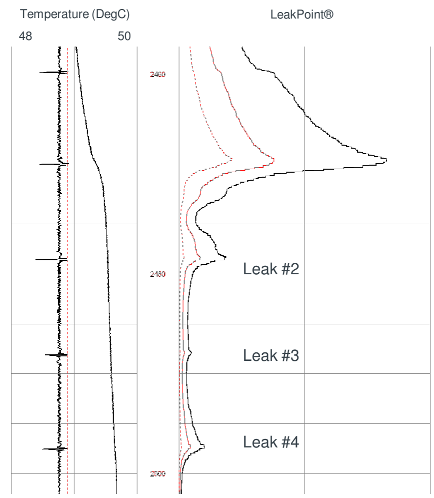
Better data, better decisions…



Where is the leak?

Better data, better decisions…



Visualising & measuring the well in 3D

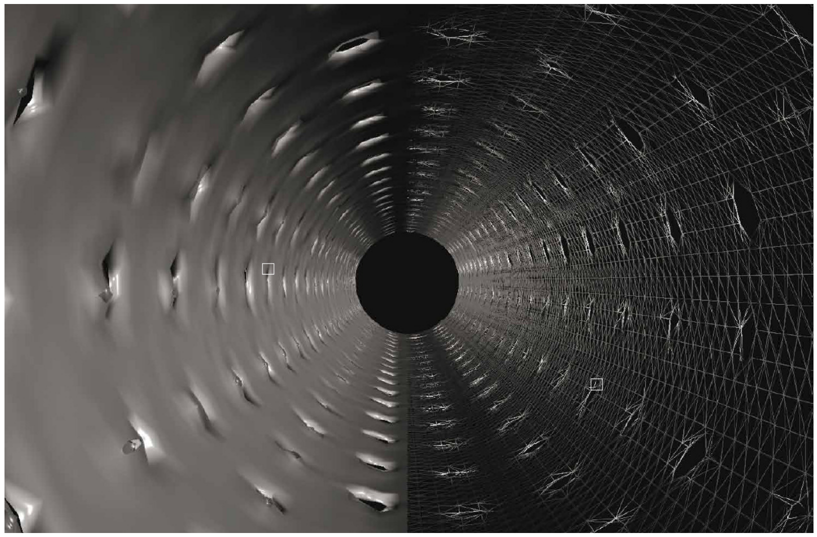
Performance eye

- Breakthrough in wellbore spatial imaging technology
  - Operates in all well fluids
  - Hi-definition 3D images
- Enabling operators to manage wells more effectively, improve well performance and extend well life.

Key benefits

- Rapid, complete diagnosis
- Improved well performance

Revealing the well in 3D with startling clarity



Overview of Archer

Archer

Seawell
Noble Platform Drilling
Peak Well Solutions
TecWel
Gray Wireline
Universal Wireline
Allis-Chalmers Energy

We are Archer
The well company

Better well integrity. © Archer 2011 23

Archer

Our purpose:

Deliver better wells to help our customers produce more oil and gas.

Better well integrity. © Archer 2011 24

Our portfolio structure

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Drilling services	Well services
Platform drilling	Wireline intervention
Land drilling	Wireline logging
Modular rigs	Integrity diagnostics
Directional drilling	Imaging
Drill bits	Production monitoring
Drilling & Completion fluids	Coiled tubing
Tubular handling	Completion services
Cementing tools	Fishing
Plugs & Packers	Specialist intervention
Underbalanced services	
Rentals	
Engineering	

Our global reach

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Thank you.

Questions?

USA gas: Corps fears that fracking may hurt dams

August 1st 2011 Printer version

FROM ACQUIRE MEDIA - NEWSEDGE

[Dallas Morning News (TX)]

The U.S. Army Corps of Engineers is concerned that hydraulic fracturing of natural-gas wells near its dams -- such as the one at Joe Pool Lake in southwestern Dallas County -- could threaten dam safety.

In most of Texas and several other states, the corps has declared a 3,000-foot buffer around its dams and water-control structures within which it will not allow new wells, drilling pads or pipelines.

The corps also has a national team studying potential risks to dam safety from minerals extraction.

"We want to feel confident that our projects are safe," said Anita Branch, regional technical specialist in geotechnical engineering for the corps' Fort Worth office. "That's always our No. 1 priority."

Hydraulic fracturing, or fracking, in which drillers inject millions of gallons of water at extreme pressures to fracture rock and release gas, tops the corps' list of worries.

The corps wants to know whether increased geological pressures from fracking could cause differential movement, or shifts along natural faults, weakening dam foundations.

"That could precipitate a fairly quick failure if it was not detected in time," Branch said.

Two less worrisome possibilities are also under review. One is whether extracting large volumes of gas beneath or near a dam might make rock and soil subside.

Another is whether huge amounts of liquid waste from drilling, pumped into disposal wells, can trigger earthquakes.

Questions about dam safety could add another potential complication to shale gas, which has become a major source of natural gas nationwide.

The combination of fracturing and horizontal drilling -- running pipe a mile or more from the wellhead to reach the gas -- has made possible tens of thousands of new wells, including in North Texas' Barnett Shale region.

At least in the case of dam safety, the corps' questions suggest there might be little or no research supporting blanket assurances that the practice poses no public risk.

It also shows that the government has been slow to study the potential threat.

New wells have been drilled or permitted within the 3,000-foot zone around Joe Pool Lake's dam, for example, but only recently has the corps responded to complaints that wells might harm dams.

Federal jurisdiction is limited by the corps' incomplete ownership of surface title and mineral rights beneath its own reservoirs -- decisions made decades ago to save money.

For that reason and others, including the nearly complete lack of scientific research to prove or disprove a risk, any national policy on wells near dams seems far off.

Caution advised

The Texas Railroad Commission, the state's oil and gas regulator, said the corps had not contacted it about dam safety concerns or told it about a 3,000-foot buffer around corps dams.

Spokeswoman Ramona Nye said in an email the agency was not aware of cases in which oil or gas wells harmed dams.

Texas has no general rule keeping wells a certain distance from dams but would consider a scientifically and factually valid request to do so from the corps, Nye said.

In 2009, the Railroad Commission set a no-drilling buffer zone around an underground gas-storage depot in Jack County, she said.

The American Petroleum Institute, the largest U.S. oil and gas trade group and a strong supporter of fracking in natural-gas production, did not respond to a request for comment on the corps' inquiries.

The organization says on its website that "a comprehensive set of federal, state, and local laws addresses every aspect of exploration and production operations. These include well design, location, spacing, operation, water and waste management and disposal, air emissions, wildlife protection, surface impacts and health and safety."

A check of institute publications on fracking did not turn up discussions of dam safety.

Two dam safety experts said they believe the corps is asking valid questions.

Bruce Tschantz, professor emeritus of civil and environmental engineering at the University of Tennessee, said the lack of scientific research or published studies on fracking's potential effects on dams justified special care.

Tschantz is also a former White House adviser and the first chief of dam safety at the Federal Emergency Management Agency.

"Until the science involving any short- and long-term relationship between hydraulic fracturing and foundation destabilization, dam safety and reservoir stability is better understood," he said in an email, "it is my general opinion as a hydraulic engineer that we should approach hydrofracturing in the vicinity of these structures very cautiously.

"This wisdom is especially important for hydrofracturing around high-hazard classes of dams." A high-hazard dam is one with great potential for loss of life and property in case of a failure. It does not mean that a dam failure is likely.

Stephen Wright, professor of civil, architectural and environmental engineering at the University of Texas, noted that problems with clay shales have led to at least two dam failures in Texas, although neither resulted in deaths. He said the corps was right to err on the side of safety.

"It seems reasonable that the corps is researching this issue," Wright said, adding that the search for answers could be long and complex.

"I am pleased that the corps takes the position of placing public safety of paramount importance. I hope everyone would be as conscientious."

Marc McCord of Dallas, an opponent of fracking, also welcomed the corps' interest in possible threats to its dams.

However, after talking with corps officials for months about natural-gas wells near Joe Pool Lake's dam, he said he's seen little movement toward action by either federal or Texas agencies.

"We have multiple agencies failing to enforce the law and each blaming it on another so that nothing is done to protect the general public from commercial enterprises that seek to profit at citizen expense," McCord said.

Most of the public dispute over the expansion of natural-gas drilling has been over fracking's possible water-quality impacts.

The Texas Railroad Commission and the gas industry say there is no documented case of fracking polluting drinking water. Environmentalists dispute that.

In December, the Environmental Protection Agency accused Range Production of polluting drinking-water wells in Parker County. Range denies that its wells are to blame. The company is contesting an EPA order before the U.S. Fifth Circuit Court of Appeals in New Orleans.

Increased pressures

The corps' concern with gas wells isn't over water quality.

"Ours is specifically associated with the safety and integrity of our projects," said the corps' Branch. "It's a different way of looking at it than most folks have done in the past."

Fracking usually takes place thousands of feet underground, so deep that many experts say it can have little or no effect near the surface.

But corps experts have envisioned a scenario in which naturally occurring faults might transfer the high-pressure force of fracking upward toward a dam's foundation.

"They're basically changing the stress state of the existing geology," Branch said. "You've got the geology as it exists today, and they're going in and changing that by increasing the pressures that are in that.

"And those increased pressures are associated with those high pressures used as part of the hydrofracturing process."

The weight of a reservoir's water also applies great pressure to the earth, but in a uniform load rather than the concentrated force of fracking, Branch said.

"The fracture pressures they're using are in the neighborhood of 8,000 per square inch, and that's a much more significant load than you get from the weight of the pool," she said.

Potential damage to a dam from differential movement of the earth shifting along a fault would probably be gradual, allowing repairs as it happens, Branch said. But it could be quick, posing immediate risks, she added.

"We know that based on experiences elsewhere, these are concerns that have been noted," Branch said. "That's why we want to make sure that we fully understand the mechanisms that are developed so we can develop appropriate policy to address those."Finding those answers will be complicated because every dam has different local geology. The variations may be great enough to prevent the adoption of a national buffer zone to cover all federal dams.

The 3,000-foot buffer that Brig. Gen. Thomas Kula, commander of the corps' Southwestern Division, ordered March 17 is not impermeable. It does not prevent wells on land where the corps did not obtain ownership or mineral rights when it built a dam and reservoir.

No current law or rule lets the corps ban all drilling on land it does not control through ownership or mineral rights, Kula noted in his order.

Kula ordered corps offices in his division to examine oil and gas projects within 3,000 feet of a corps dam or water-control structure. Regardless of ownership, if the agency determines that a well would endanger dam safety, it can take legal action.

Kula's order covers corps operations in all or parts of Texas, Oklahoma, Louisiana, Arkansas, Kansas and Missouri.

McCord, the Dallas environmentalist who has pressed the corps to take a tougher stance on wells near its dams, said corps officials told him some companies had complied voluntarily with the 3,000-foot buffer zone, but others had not.

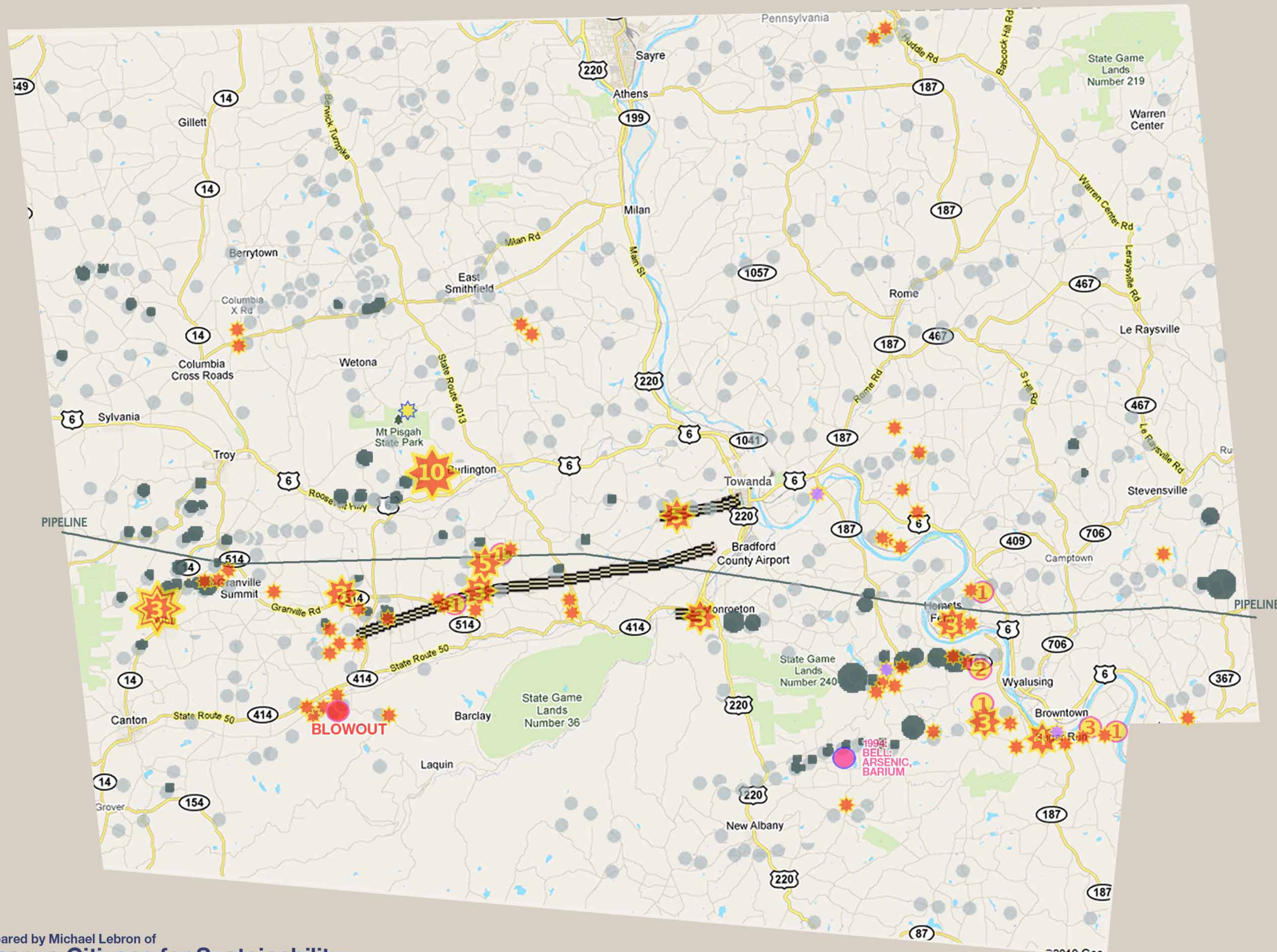
"This leads me to wonder why no governmental agency is doing its job in regulating the oil and gas industry by forcing compliance with legal restrictions on their operations," he said.

Source: Acquire Media - NewsEdge

Bradford County PA

Compromised water wells, determined by:
—personal observation
—newspaper accounts
—reports by neighbors

TOTAL: **92**
as of Aug 26, 2011

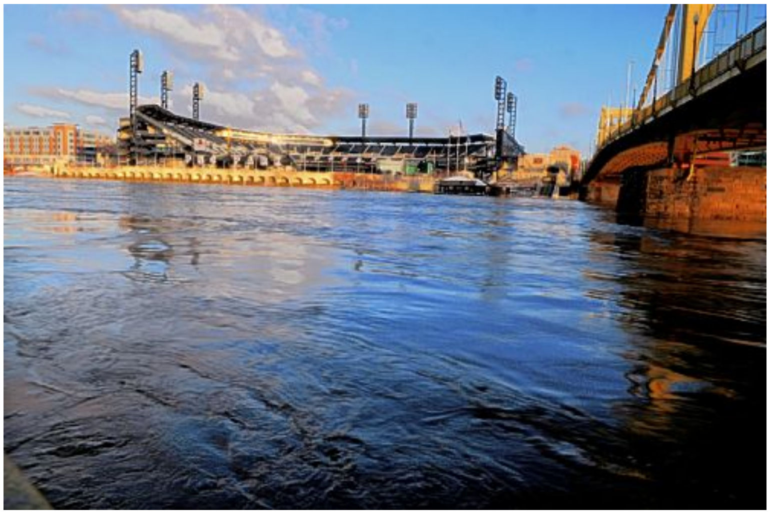


Map prepared by Michael Lebron of
Damascus Citizens for Sustainability and
New Yorkers for Sustainable Energy Solutions Statewide
Gas well locations from http://www.bradfordcountypa.org/Natural-Gas.asp?specifTab=2

post-gazette.com Pittsburgh Post-Gazette NEWS / ENVIRONMENT

Bromide: A concern in drilling wastewater

Sunday, March 13, 2011
By Don Hopey, Pittsburgh Post-Gazette



Darrell Sapp/Post-Gazette

The high waters of the Allegheny River flow along the 10th Street Bypass last week. Public water suppliers in Pittsburgh and elsewhere in the region are concerned about higher levels of bromide in rivers and streams as natural gas drilling increases.

Ballooning bromide concentrations in the region's rivers, occurring as Marcellus Shale wastewater discharges increase, is a much bigger worry than the risk of high radiation levels, public water suppliers say.

Unlike radiation, which so far has shown up at scary levels only in Marcellus Shale hydraulic fracturing wastewater sampling done at wellheads, the spike in salty bromides in Western Pennsylvania's rivers and creeks has already put some public water suppliers into violation of federal safe drinking water standards.

Others, like the Pittsburgh Water and Sewer Authority, haven't exceeded those limits but have been pushed up against them. Some have had to change the way they treat water.

Bromide is a salty substance commonly found in seawater. It was once used in sedatives and headache remedies like Bromo-Seltzer until it was withdrawn because of concerns about toxicity. When it shows up at elevated levels in freshwater, it is due to human activities. The problem isn't so much the bromide in the river but what happens when that river water is treated to become drinking water.

Bromide facilitates formation of brominated trihalomethanes, also known as THMs, when it is exposed to disinfectant processes in water treatment plants. THMs are volatile organic liquid compounds.

Studies show a link between ingestion of and exposure to THMs and several types of cancer and birth defects.

"Our biggest concerns are about bromide, which has become a problem over the last six months or so," said Stanley States, water quality manager with the Pittsburgh Water and Sewer Authority, which draws water from the Allegheny River for its 400,000 customers. "Trihalomethanes are strictly regulated because of the health risks.

We've seen levels that are threatening the standards."

The federal safe drinking water standard for THMs is 80 micrograms per cubic liter, and removing them from finished drinking water is difficult. Keeping bromide levels in raw water sources low is a much easier way to address the problem.

Mr. States said the elevated bromide levels in the river could be coming from municipal sewage treatment plants and brine treatment plants handling Marcellus Shale drilling and hydrofracking wastewater or from discharges by coal-fired power plants water discharges. He said four municipal sewage facilities and four brine treatment plants are handling and discharging Marcellus Shale wastewater upriver from Pittsburgh's drinking water intake pipe in Aspinwall.

"Something's changed and it could possibly be related to the treating of Marcellus Shale drilling wastewater," Mr. States said. "There will be a lot more Marcellus Shale wells operating in the region before there are a whole lot less and our concern is in providing safe drinking water. We're not anti-Marcellus Shale. We're anti-bromide."

Problem through the region

Pittsburgh is not alone. The Wilkinsburg-Penn Joint Water Authority issued a notice to its customers in January informing them of the bromide problem and said it was necessary to change its water treatment methods to stay in compliance with state and federal drinking water standards.

"Due to the sudden increase in bromide concentration in the Allegheny River, all water suppliers are beginning to have a problem controlling this trihalomethane formation," the authority wrote on its Web page. "All water purveyors on the Allegheny River System are working together to try and find out the source of the elevated bromide levels."

Mr. States said a study is under way on the Allegheny River and its tributaries to identify sources of bromide in the river.

The Department of Environmental Protection is participating in that river sampling study and another in the Monongahela River watershed.

Katy Gresh, a DEP spokeswoman, said the department plans to order the industrial brine plants, sewage treatment facilities and coal-powered power plants on the rivers to conduct sampling at their discharge pipes.

"We will get and review those results," Ms. Gresh said. "If we can control the largest contributors, that will help solve the problem."

Jeanne VanBriesen, a Carnegie Mellon University professor of civil and environmental engineering, said testing there showed an unusual spike in bromide levels in July and August. Although they've tapered a bit since then, they remain higher than normal, said Ms. VanBriesen, who has been studying water quality in the Monongahela River since fall 2009.

She said the two biggest sources of bromide in the watershed are Marcellus wastewater from sewage treatment facilities and wastewater from new smokestack scrubbers at coal-fired power plants. The plants cannot remove the bromide in wastewater.

Bromide levels vary in discharges from both sources, but bromide is generally found at higher concentrations in Marcellus wastewater.

"It's difficult to make a definitive statement about where it's all coming from, but we do know it's going into our drinking water treatment plants and affecting the treatment of our water," Ms. VanBriesen said. "The most logical way to fix that is to reduce the amount of bromide in the rivers and creeks."

Millions of gallons

Marcellus Shale drilling and hydraulic fracturing operations use an average of 4 million gallons of water to drill and "frack" each well. The drilling industry says it recycles approximately 70 percent of the wastewater from its well fracking operations, but millions of gallons are still funneled through 11 sewage treatment facilities and five brine treatment plants, then discharged into the state's rivers and streams.

Together, the eight facilities on the Allegheny and its tributaries are allowed to discharge an average of 1.5 million gallons of Marcellus drilling wastewater and hydraulic fracturing fluid a day, according to state Department of Environmental Protection records. Marcellus discharges from three treatment facilities on the Monongahela River total 185,000 gallons a day. Another 650,000 gallons a day flow into the Ohio and its tributaries.

Drilling companies and the Marcellus Shale Coalition, an advocacy and lobbying organization representing most of the companies doing shale gas drilling in Pennsylvania, said the industry isn't to blame for higher bromide levels.

"When you look at the amount of Marcellus Shale wastewater that is being discharged it's low" compared to the river flows, said Matt Pitzarella, a spokesman for Range Resources. "So those [bromide] increases are not an impact of Marcellus Shale." Range Resources recycled 90 percent of its wastewater last year and has set a goal of 100 percent for 2011.

"We certainly see this as a non-Marcellus issue," said Steve Forde, a shale coalition spokesman, who cited a 2010 U.S. Geological Survey study that noted higher bromide levels nationwide, especially in urban areas. "Road salt use has been identified as one of the culprits for that."

Ms. VanBriesen said that's not likely because road salt contains more chloride and little bromide, and her water testing didn't find a corresponding spike in chloride levels. Plus the bromide spike in the rivers first occurred in the summer.

"So to implicate road salt, well, I wouldn't buy that," she said. "The bromide spike happened in July and August when you wouldn't be applying road salt. So that wasn't a factor."

Changing treatment process

Whatever the origin of the bromide spike, Jerry Schulte, manager of source water protection for the Ohio River Valley Water Sanitation Commission, said bromide is "absolutely an issue" for water treatment plants.

"We've identified bromide as a compound of concern," Mr. Schulte said, adding that ORSANCO's triennial review of pollution control standards in April will focus on developing a new, first-time standard for bromide in the watershed.

Discharges of bromides and bromide levels in rivers or streams are not now regulated by ORSANCO or by the U.S. Environmental Protection Agency.

The Josephine brine treatment facility, also known as Franklin Brine, on Blacklick

Creek in the Allegheny's watershed, discharges an average of 120,000 gallons a day of Marcellus wastewater that, at peak levels, contains high concentrations of bromide, chlorides and total dissolved solids, according to sampling done by the University of Pittsburgh's Center for Healthy Environments and Communities.

"There's pretty high bromide going into the creek. Certainly it is a public health threat," said Conrad Dan Volz, director of the Center for Healthy Environments and Communities. "And to remove brominated THMs, that's going to break the bank for public water systems."

Water treatment plants can get around the bromide problem by changing their treatment methods -- substituting chloramines for the chlorides they normally use in the disinfection process. That's what the Wilkinsburg-Penn water authority did.

The chloramines produce different, less toxic, treatment byproducts, but those can produce other problems, including causing lead and copper to leach out of old water pipelines and into drinking water as happened in Washington, D.C., when it made such a switch in 2000.

Ms. VanBriesen said water utilities making such a change can add phosphate to their finished water to prevent lead from leaching out of the pipes.

Another way to avoid THMs, she said, is to change the way water utilities mix, aerate and store their finished water, and a number of suppliers are considering that.

One water treatment facility that has had problems with keeping THM concentrations in finished water below the 80 parts per billion federal standard is Beaver Falls, in Beaver County, which was required to notify its 50,000 customers in 22 municipalities of the problem for the first three quarters of 2010.

The authority changed its treatment methods, from chlorine to chloramines, which don't form THMs, at a cost of approximately $15,000 last year. That allowed the water supplier to meet the standard for the last three months of the year, said Jim Riggio, general manager of the water system.

Although testing done by the state DEP hasn't been able to pinpoint a cause of the higher bromide levels in the Beaver River, Mr. Riggio said they coincided with upriver discharges of treated Marcellus Shale fracking wastewater.

"We went from non-detectable levels of bromide to increased levels a couple of years ago," Mr. Riggio said. "When I see the whole frack water thing taking off and the same time we start to have problems, well, until you can tell me different, that's what I assume it is. And it seems like a lot of the water suppliers on the Beaver and Mon rivers had similar problems to what we did."

Correction/Clarification: (Published March 18, 2011) A graphic accompanying a Sunday story on bromide concentrations in area rivers affecting water treatment facilities incorrectly identified the Washington-East Washington Joint Authority as accepting and discharging Marcellus Shale drilling wastewater. It considered doing so but has never accepted drilling wastewater

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Don Hopey: dhopey@post-gazette.com or 412-263-1983.

First published on March 13, 2011 at 12:00 am

Casing Shear: Causes, Cases, Cures

Maurice B. Dusseault, SPE, Porous Media Research Inst., U. of Waterloo, and **Michael S. Bruno,** SPE, and **John Barrera,*** Terralog Technologies Inc.

Summary

Casing impairment leads to loss of pressure integrity, pinching of production tubing, or an inability to lower workover tools. Usually, impairment arises through shear owing to displacement of the rock strata along bedding planes or along more steeply inclined fault planes. These displacements are shear failures. They are triggered by stress concentrations generated by volume changes resulting from production or injection activity. Volume changes may arise from pressure changes, temperature changes, or solids movement (solids injection or production).

Dominant casing-deformation mechanisms are localized horizontal shear at weak lithology interfaces within the overburden; localized horizontal shear at the top of production and injection intervals; and casing buckling within the producing interval, primarily located near perforations.

Mitigating casing damage usually means reducing the amount of shear slip or finding a method of allowing slip or distortion to occur without immediately affecting the casing. Strengthening the casing-cement system seldom will eliminate shear, although in some circumstances it may retard it. Proper well location or inclination, underreaming, special completions approaches, reservoir management, and other methods exist to reduce the frequency or rate of casing shear.

Shearing Mechanisms

Casing shear is caused by rock shear. Rock shear is caused by changes in stress and pressure, induced by typical petroleum-recovery activities such as depletion, injection, and heating.

Rock Mechanics and Formation Shear. Because geomaterials are not homogeneous and isotropic, and because they display strain-weakening, rock-mass shear deformation tends to be concentrated in planes, rather than occurring as uniform shear distortion. Rock shear occurs as relative lateral displacement, often across a planar feature such as a bedding plane, joint, or fault. Even if there are no obvious pre-existing planar features, large shear strains will induce slip along specific planes as rock yields (fails) in response to large induced shear stresses. Earthquakes, landslides, and fault movements are expressions of induced shear stresses large enough to overcome natural material strength.

In cases of reservoir rock or overburden shearing, slip planes tend to develop either along interfaces between materials of different stiffness, or on existing discontinuities or weakness planes. A particularly weak stratum may be a high-porosity smectitic-shale zone or a bedding plane or surface which previously has slipped and therefore is presheared. In homogeneous intact rock subjected to large shear stresses, slip will occur on single planes, almost always near the interface between two materials of different stiffness because the shear strains responsible for slip tend to concentrate naturally where a contrast in deformation properties occurs. This concentration, for example, is responsible for delamination of composites such as plywoods or laminates. In a sand-shale sequence, shear slip will occur in the shale because it is weaker than the sandstone, but near an interface with the sandstone, where the shear strains are focused by deformation. Exceptionally, a particularly weak bed or slickensided zone in a shale sequence will shear before an interface because of the low intrinsic strength.

Slip Criteria in Geomaterials. Formation shear is analyzed in terms of stress/strain behavior and rock strength. The critical mechanical factors are the geomaterial deformation parameters, the shear strength of the various units and interfaces, and the changes in stress, temperature, and volume to which the strata are exposed. These changes arise because of injection and production activity.

Fig. 1 depicts three basic stress definitions. Fig. 1a shows the disposition of the principal compressive stresses at a point. Seven independent parameters are needed to fully specify fully the stress state: the orthogonal major, σ_1, intermediate, σ_2, and minor, σ_3, principal stresses, the orientation of these stresses (stipulated as three direction cosines), and the pore pressure, p_o. Fig. 1b shows the stress terms commonly used in petroleum engineering, defined with respect to the ground surface. It is usually assumed that the vertical stress, σ_v, is one of the principal stresses; therefore, the other two are the larger and smaller horizontal stresses, σ_H and σ_h, respectively. Stresses may be estimated or measured by various methods outlined in a number of articles.[1,2] The natural shear stresses, τ, are highest on planes 45° from the principal-stress planes, and the maximum shear stress, τ_{max}, is defined as $(\sigma_1-\sigma_3)/2$. Thus, the larger the natural difference in the major and minor principal stresses, the greater the shear stress, and the closer a rock is to a state of failure or shear slip. However, a rock generally will not slip along the plane of maximum shear stress, but at an angle to it, as shown in the triaxial test schematic in Fig. 1c.

A common slip criterion for a geomaterial (or for a plane of weakness in the strata), called the Mohr-Coulomb (MC) criterion, is expressed in terms of effective stresses as shown in **Fig. 2.** The effective (or matrix) stress, σ', is defined by Terzaghi's law, $\sigma'=\sigma-p$, often expressed tensorially as $\sigma'_{ij}=\sigma_{ij}-p\delta_{ij}$. Simply stated, the important factor in formation shear is the effective stress that is transferred by grain-to-grain (matrix) forces, and this is affected not only by the boundary loads and the depth of burial, but also by the fluid pressure, p. Higher fluid pressures mean lower effective stresses.

The slip criterion is referred to by many different terms: shear strength, failure criterion, yield criterion, or Coulomb criterion. It is expressed often as an equation that stipulates the maximum permissible shear stress along the slip surface being analyzed. The simplest linear form, the linear MC criterion, may be written as

$$\tau_{max}=c'+\sigma'_n\tan\phi'. \quad (1)$$

Here, τ_{max}=the maximum shear stress that the plane can sustain before slip; c'=the cohesion of the rock; σ'_n=the normal effective stress across the slip plane; and ϕ'=the internal friction angle. The material parameters c' and ϕ' are determined empirically from testing and are defined in Fig. 2.

The normal effective stress across potential slip surfaces, σ'_n, is determined by calculations, usually with a finite element numerical model that can account for different strata properties, boundary conditions, and changes in volume, temperature, pressure, and stresses. Often, nonlinear (curvilinear) MC criteria are used because a linear MC criterion is insufficient, but all MC criteria are nevertheless based on laboratory test results. Finally, one may note that many failure criteria of different forms have been published, but they all serve the same function: to relate the maximum permissible shear stress to the effective normal stress in a geomaterial.

Casing Shear. Loss of casing function occurs when the pressure integrity of the casing is impaired, or when the distortion of the

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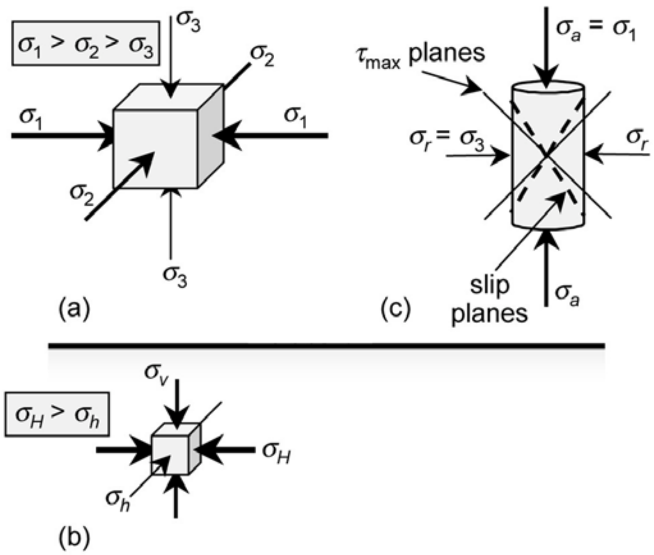

Fig. 1—Basic stress conditions: (a) principal stress; (b) in-situ stress; (c) triaxial stress.

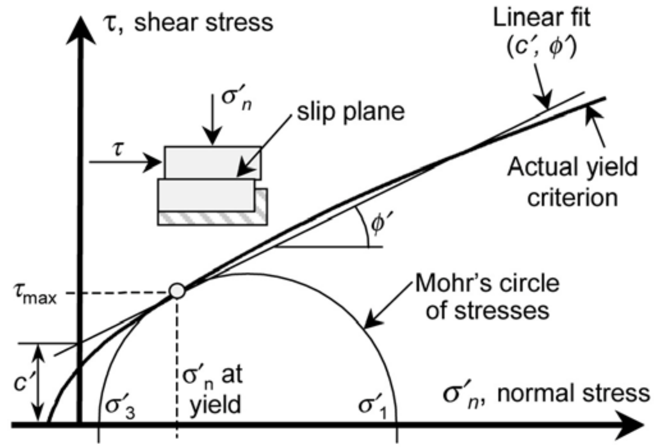

Fig. 2—Mohr-Coulomb criterion and stresses.

wellbore becomes so large that tools cannot be lowered down the hole, or the production tubing is impaired.

Pressure-integrity loss arises through two mechanisms. The casing collar threads become sufficiently distorted so that the seal is lost (thread popping), or a physical rupture of the casing develops (cracking or ripping). The former is probably more common, particularly if the casing collar is close to the slip plane.

Fig. 3 illustrates the general distortion of casing evidenced as a "dogleg," a bend sharp enough that tools cannot be lowered or production device rods cannot operate. In this diagram, the shear-displacement zone is drawn as a dislocation spread out over a limited height; but in geomaterials, it is most common to have all relative slip occurring on a single thin plane, usually only a few millimeters in thickness.

Three critical forms of well damage involving shear have been observed.

- Localized horizontal shear at weak lithology interfaces within the overburden during reservoir compaction or heave.
- Localized horizontal shear at the top of a production or injection interval caused by volume changes in the interval that arise from pressure and temperature changes.
- Casing buckling and shear within the producing interval, primarily along perforations, and mainly because of axial buckling when lateral constraint is removed, but occasionally due to shearing at a lithological interface.

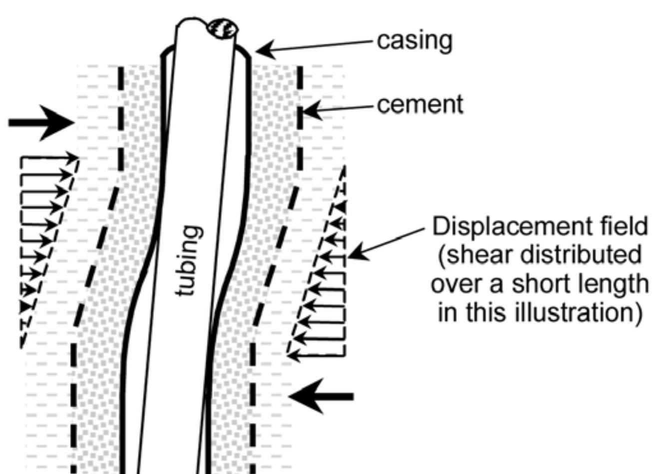

Fig. 3—Development of casing dogleg.

Compaction-Induced Shearing

Shearing that accompanies reservoir compaction or heave can induce casing shear; the larger the ΔV in the zone, the greater the casing impairment potential in the overburden.[3–9]

Compaction is a volume diminution of the reservoir induced by a reduction in p_o, usually associated with depletion. The pressure decrease causes an increase in the grain-to-grain forces, and reservoir compaction occurs as these contacts compress or crush. If the reservoir behaves as a linear elastic material, a constant coefficient of compressibility, determined from testing, suffices to give a first-order estimate of the compaction. Because compressible reservoirs are granular and rarely behave in an elastic manner, calculations of compaction require experimental compressibility data. **Fig. 4** shows an experimental compaction curve for a stratum in a high-porosity reservoir. Under conditions of drawdown Δp, (path A→B), a porosity reduction of ∼5% is evidenced. If the reservoir is thick (e.g., 100 m), this converts to 5 m compaction.

Because of the continuity of overlying rocks and the general lenticular cross-sectional shape of a reservoir, compaction is a downward and inward motion. This leads to the reactions in the overburden illustrated in **Fig. 5.** The crestal section experiences an increase in σ_h; the remote flanks experience a drop in σ_h; and the rocks above the shoulders experience an increase in the shear stress, τ.

If the shear stress anywhere in the overburden exceeds the strength of the bedding planes, low-angle slip occurs. If there is a potential for reactivation of low-angle thrust faults in the crest region, a thrusting mechanism can develop as the horizontal stresses increase, leading to the condition $\sigma_H = \sigma_1 > \sigma_v = \sigma_3$. Finally, there is the potential for a high-angle normal fault mechanism to develop on the flanks, leading to the condition $\sigma_v = \sigma_1 > \sigma_h = \sigma_3$. We have identified all three cases in practice.

In general, casing shear is most common on the shoulders of the structure where the maximum shear stress is likely to be concentrated in a flat-lying, lenticular reservoir case. Whether crestal-thrust faults or flank-normal faults develop depends on the initial tectonic stress conditions.

The mechanism of bedding-plane slip can be demonstrated by placing two strips of wood together and bending them. In the center, there is no shear slip, but slip must occur on both sides away from the central portion. Bending a telephone directory and noting the distortion patterns and slip of pages is instructive, but note that strain-weakening geomaterials concentrate shear slip along a few planes, in contrast to the telephone book in which all pages slip by each other.

Overburden flexural shear is most intense near the reservoir. The intensity drops off with distance from the reservoir; thus, casing shear is more common near the reservoir.

Injection-Induced Shearing

Injection leads to shearing by two mechanisms: higher pressure reduces the effective normal stress (Eq. 1), making shear easier;

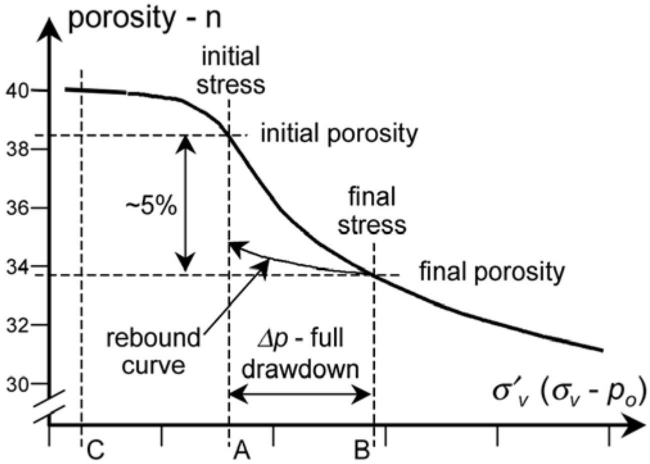

Fig. 4—Reservoir compaction curve, σ'_v vs. porosity.

and reservoir expansion leads to shearing near bounding interfaces where stresses are concentrated.

High-pressure injection, as from waterfloods, steam fracturing, etc., reduces the effective stress, leading to a volumetric expansion, as illustrated by path A→C in Fig. 4. The bounding strata, being relatively impermeable seal rocks, do not experience a similar stress change; therefore, they have no tendency to expand. **Fig. 6** demonstrates that as a pressured zone propagates from the injection point and the permeable rock tries to expand outward, a large shear stress is imposed on the interface between the reservoir and the bounding strata. If this shear stress exceeds the interface strength, slip ensues, and casings in offset wells can be impaired. In Fig. 6, the injection well may be a single well or a line of wells under injection; the latter case is more critical for shear slip.

Fig. 7 illustrates how large-volume high-pressure injection can trigger fault reactivation by reducing the normal stress across pre-existing slip planes.

In the extreme case of injection above fracture pressure, in heavy-oil reservoirs for example, the parting plane becomes separated ($\sigma'_n \rightarrow 0$). If the fracture plane is at an angle to the principal stress orientations, displacement occurs, generating a slip plane in advance of the fracture plane (Fig. 7). If the pore pressure in the well vicinity is so large as to reduce the shear strength of the reservoir to a low value, the injection-well casing may not distort, as the low-strength, highly pressured sand can deform easily around the casing.

High injection pressures tend to migrate upward along the cement-rock-casing interfaces by a process of circumferential fracture generation and migration, particularly if the cement shrank when setting. Pressurization of any weak zone at a higher elevation means a greatly increased likelihood for shearing, particularly in cases where the in-situ stress differences are large (i.e., existing large, natural shear stresses).

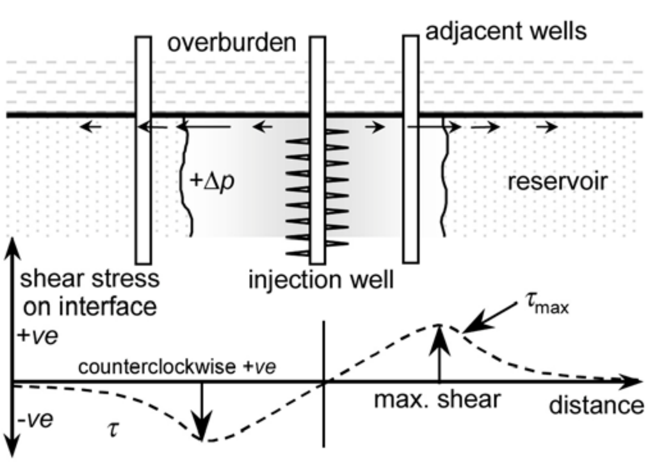

Fig. 6—Injection-induced interface shear stress.

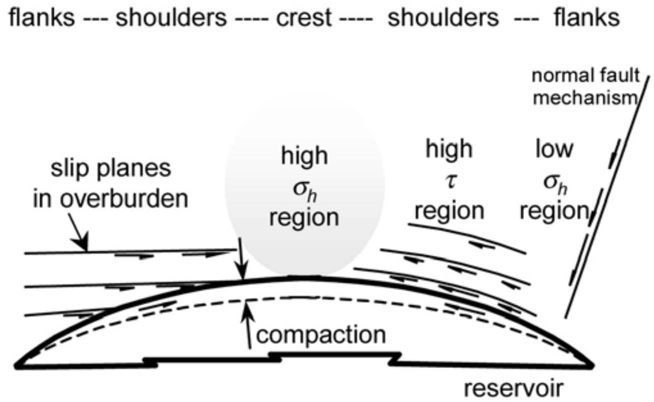

Fig. 5—Compacting reservoir bedding-plane slip.

Casing Shear During Production

Fluids production leads to an increase in effective stresses, which causes a volume decrease in the reservoir similar to path A→B in Fig. 4. For a single well (or line of wells) in the case of a limited distance drawdown zone, this leads to a shear-stress concentration similar to the reservoir pressuring case, but the shear displacement along the interfaces is in the opposite direction (as in Fig. 6, but with the opposite sense of motion). If the compressibility of the reservoir is substantial, the strains may be large enough to impair casing.

As a reservoir is being produced, shrinkage tends to cause a remote lateral unloading in the depleted zone and in advance of the pressure front. This leads toward normal fault mechanisms **(Fig. 8),** particularly in reservoirs in tectonically relaxed areas ($\sigma_H < \sigma_h < \sigma_v$) where initial lateral-stress gradients are low, and particularly if pre-existing faults are present.

Casing Shear in Thermal Processes

Steaming processes may involve ΔT values as large as 250°C; higher temperature changes are associated with firefloods. The thermal-expansion coefficient of a typical high-porosity sand is $\sim 6-8\times10^{-6}\,\mu\varepsilon$/°C; therefore, an expansion of 0.2% by volume is a reasonable expectation. Because geomaterials in situ are stiff ($E > 5\times10^6$ GPa usually), even much smaller expansions can lead to large stress changes and shear slip.

Consider a case of massive advective heating of a zone in a sandstone reservoir as shown in **Fig. 9.** Rock expansion generates increased stresses in some directions, decreased stresses in others (overall stress equilibrium must be maintained). The outwardly directed stress, σ_r, increases as the expanding zone is constrained by the surrounding rock. The condition $\sigma_H > \sigma_h > \sigma_v$ is generated, and a thrust fault (low-angle) condition can be reached in the unheated rock in advance of the thermal front.

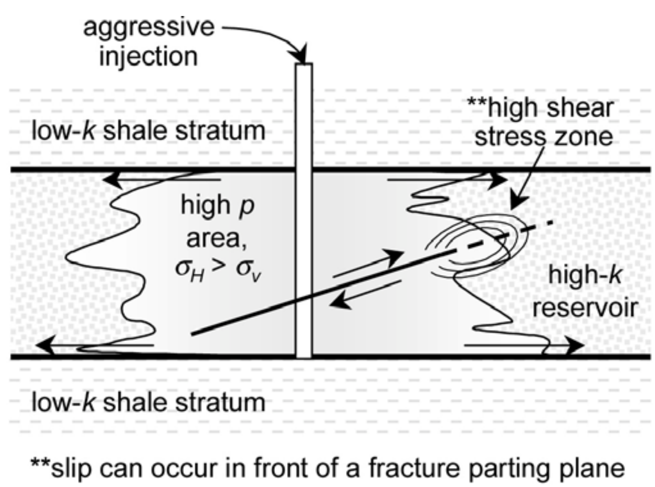

Fig. 7—Low-angle injection-induced shearing.

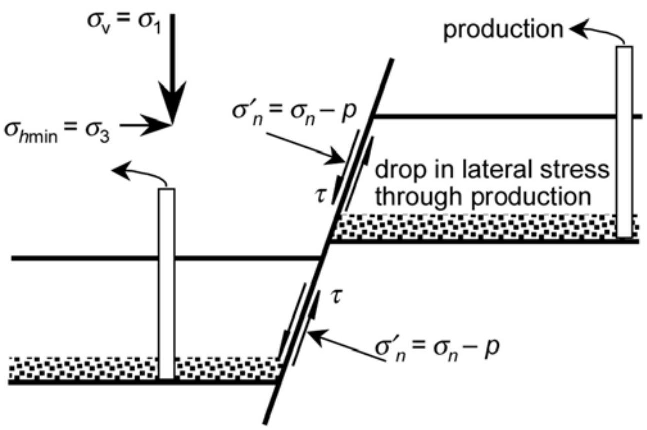

Fig. 8—Normal fault-triggering during production.

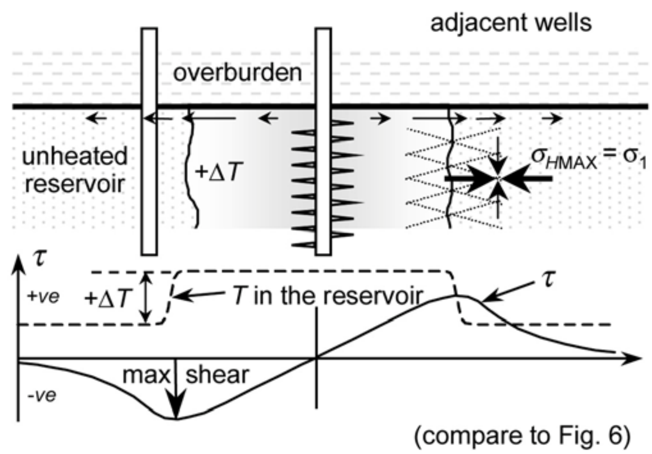

Fig. 9—Induced shearing, thermal-injection cases.

Furthermore, strain incompatibility and shearing develop at upper and lower interfaces. The reservoir is heated rapidly because of advective heat transfer, and bounding, low-permeability strata are heated very slowly through conduction. Shear-stress concentrations arise across the interfaces, and slip ensues when the material strength is exceeded. The shear/slip zone is most intense at the front of a steep thermal gradient, and in the case of a symmetric vertical well, the induced shear-stress concentration along the interface at the injection wellbore will be small (Fig. 9).

The worst case for shear of offset wells in a thermal project probably arises in line-drive steam injection, as all deformation is forced outward along the front. Cyclic steam stimulation in single wells leads to lower shear-stress concentrations at the leading edge and slower propagation because of the radial spreading effects.

If a thermal project also involves high-pressure injection, and with the exception of steam-assisted gravity drainage they usually do, there is a much greater chance for casing shear. The thermal-expansion effects generate large shear stresses, whereas the high pore pressures reduce the effective stresses across potential failure planes. Given that the differential thermal straining associated with advancing temperature fronts also tends to rupture grain-to-grain mineral cohesion, the potential for shear slip is even greater.

Steaming also involves high pressures that can migrate along the cement/rock interface of wells to higher elevations, helping trigger slip in shallower zones along planes of weakness (usually bedding planes). Casing rupture from combined thermal stresses and corrosion is common in thermal projects, making high-pressure leakage at higher elevations even more common.

Casing Shear in Slurry Fracture Injection Projects

Slurry fracture injection (SFI™) involves placing large volumes of solid wastes into permeable reservoirs through the cyclic injection of an aqueous slurry.[10,11] The shape of the injection zone is complex, with components of vertical, horizontal, and inclined fractures. Because permeable reservoirs are used, pressures tend to dissipate after the injection cycles that last 8 to 12 hours daily; during active injection, pressures may migrate upward along the casing, leading to pressurization of overlying zones that may shear.

The major factor leading to shear in SFI™ projects is the large permanent volume change (15 to 50 000 m^3) arising from solids placement. Upward flexure of the overburden, similar to but in the reverse sense of Fig. 5, leads to bedding-plane slip. In a manner similar to the effects of thermal expansion depicted in Fig. 9, shear of any weak interfaces just above the injection zone can occur, particularly if there is high-pressure leakage along casing.

Ekofisk and Valhall: Compaction Shearing

The Ekofisk and Valhall fields in the North Sea produce from relatively deep and compressible chalk formations. At Ekofisk, deformations have been measured in most of the wells in the field. Casing damage at the Valhall field occurs in both the overburden and reservoir, but overburden damage appears to be more uniformly distributed across the field, compared to the Ekofisk case.

The thick chalk reservoirs at Ekofisk and Valhall initially had zones with porosities as high as 50% near the top of the structures. The reservoirs were overpressured (~85% of σ_v), and production drawdown soon led to massive compaction and casing shear.[12] As of 2000, Ekofisk has experienced more than 10 m of reservoir compaction, and most wells penetrating the reservoir have been impaired by shearing at least once, in some cases as many as four times. Each impairment requires well plugging followed by a new sidetrack.

Casing-shear zones are found in the overpressured shale caprock above the reservoir. Deformations are concentrated in the shoulders of the reservoir, with a large percentage occurring near the Balder shale interval about 160 m feet above the reservoir top. The specific slip planes generally are located at sand/shale interfaces, and they have been shown to emit microseismic bursts over time because of the episodic stick-slip behavior typical of geomaterials. Caliper logs show a distinct, localized shear pattern to these deformations. Operators at Ekofisk have used underreaming **(Fig. 10)** across the Balder formation to mitigate shear damage. This technique appears to be successful.

Deformations within the producing horizon most often appear as column buckling, are generally near perforated intervals, and usually are associated with solids production. Strictly speaking, this is not a shearing process, but more of a column buckling caused by axial loading and loss of lateral restraint resulting from solids production and reduction of lateral stress through depletion **(Fig. 11).** Mitigation strategies at Valhall to counteract buckling have included the use of concentric and heavy-wall casing within the producing formation.

Further compaction will continue to generate shear slip of zones, and the magnitude of compaction is so exceptionally large in these reservoirs that thrust faulting in the central portion or normal faulting at the flanks are definite possibilities.

Wilmington Earthquakes: Production Shearing

The Wilmington field in Long Beach, California is located near the southwestern edge of the Los Angeles sedimentary basin. The producing structure is a broad, asymmetrical anticline, broken by a series of normal faults. Production comes from seven zones of Pliocene- and Miocene-age high-porosity sands (33 to 37%) at 800 to 1900 m depth that have not experienced deeper burial in geological times.[13] Massive reservoir compaction and production-stress changes induced severe casing damage to more than 500 wells, including compression damage within the producing interval and shear damage within the producing intervals and in the overburden. Casing-collar logs show that 15-m casing joints were shortened as much as 400 mm within producing intervals. Surface subsidence at the field eventually reached approximately 9.5 m and was eventually brought under control by overbalanced water injection ($V_{inj} > V_{prod}$) in the late 1960's. The graph in **Fig. 12** shows that before subsidence was controlled completely, however, well damage at Wilmington was mitigated effectively using underreaming.

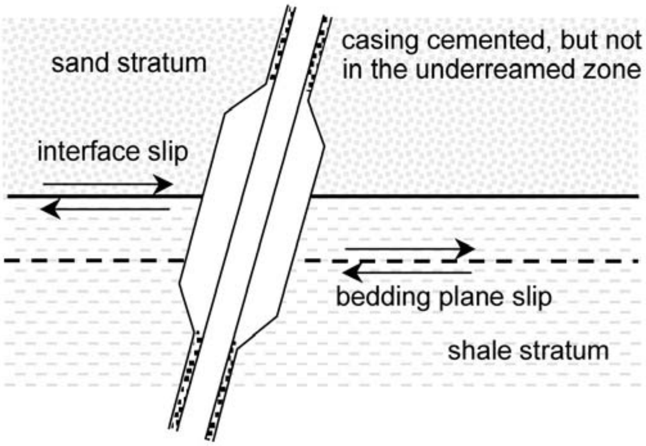

Fig. 10—Underreaming to reduce dogleg rate.

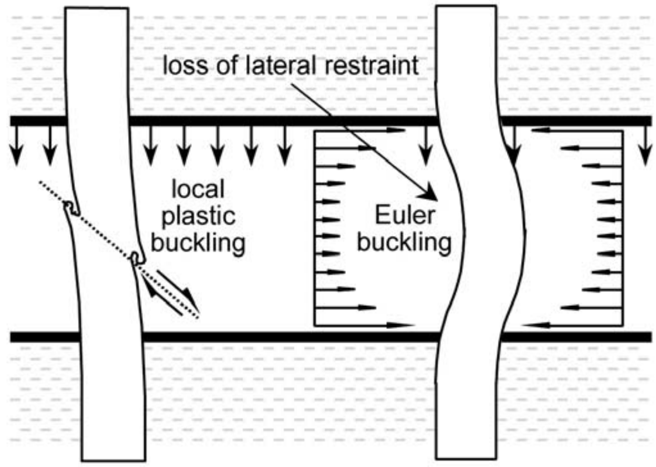

Fig. 11—Euler buckling and plastic buckling.

The vast majority of well damage at Wilmington was associated with subsidence-induced bedding plane slip and low angle faulting. During the period of maximum subsidence in the 1950's, five or six small, shallow earthquakes of relatively low magnitude (M2 to M4) were recorded in the field. Hundreds of oilwell casings were sheared during the earthquakes, and much of the shear movement was confined to thin beds of clay shale, about 2 m thick, lying between much thicker beds of sandstone and siltstone. The maximum horizontal shearing movement measured in one thin bed was approximately 225 mm. The damage areas were located away from the center of the subsidence bowl, at the steepest gradient of the subsidence contours,[7] in the shoulders of the reservoir (see Fig. 5). **Fig. 13** presents an outline of the areas of well damage superimposed on the field subsidence contours. The lateral position of well damage corresponded with the developing shoulders of the subsidence bowl (maximum slip region), not with the regions of maximum subsidence.

Well damage was concentrated at weak horizontal bedding planes in the overburden. These planes slipped both seismically and aseismically during the period from 1945 to 1970. In addition to horizontal slip, there was some evidence of high-angle normal fault reactivation because of the stress changes in the reservoir; this was the likely mechanism associated with the seismic well losses in the mid-1950's. Some minor additional well damage continued through the 1980's, primarily located around aseismically slipping, steep normal fault within the producing interval (mechanism likely similar to that shown in Fig. 8).

Athabasca Cyclic Steam Injection Shearing

Fig. 14 depicts the Canadian Gregoire Lake thermal project located 50 km south of Fort McMurray. In the 1970's, prolonged steam injection took place along a line of wells in an attempt to reduce the viscosity and generate oil flow to offset wells. Injection of steam took place at a depth of about 250 m near the bottom of a thick (45 m) oil-sand deposit. Injection was above fracture pressure throughout the steaming because the extremely low hydraulic conductivity of the heavy-oil sand (<10°API) predicates against any matrix flow while the oil sand is cool.

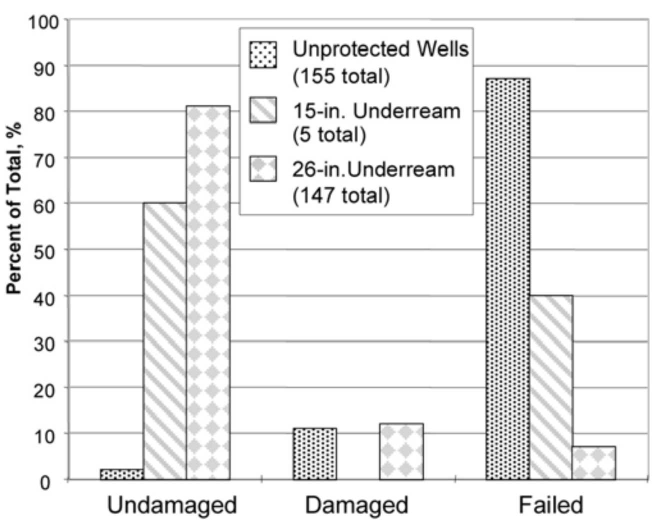

Fig. 12—UPRC well damage in Wilmington field during 4 April 1961 shallow earthquake.

The heavy-oil saturated (9.5°API) McMurray formation zone is mainly a coarse-grained uncemented quartzose sandstone of 30% porosity that has been geologically overcompacted by a cycle of deeper burial (>500 m) and subsequent erosion, leading to the stress condition $\sigma_H > \sigma_h > \sigma_v$ at these depths in this region. The compaction potential of the reservoir is negligible, but there is a tendency to shear and dilate as steep temperature gradients propagate through the materials, exacerbating the effects of temperature-induced ΔV.

Fig. 15 illustrates the lithostratigraphy. The reservoir contains a few thin oil-free strata and is characterized overall by a decreasing grain size and increasing incidence of shaly partings higher in the formation. At the upper interface, near the top of the McMurray formation, is a stiff 0.3- to 0.5-m thick concretionary bed (siderite cement with a low porosity) that is probably 3 to 5 times stiffer than the surrounding strata. This bed is an ideal zone for high shear-stress concentrations.

After some period of injection above fracture pressure, casing impairment was observed in the middle of the oil zone in an offset well. Later, casing shear was observed at the bottom of the interface with the concretionary bed **(Fig. 16),** consistent with a shallow-angle rising-slip feature, causing the well-rupture sequence A→B→C. Eventually, the majority of the offset wells evidenced failures in shear, often related to collar thread popping or to an inability to lower tools. Commonly, casing-pressure-integrity impairment was noted without the presence of a thermal anomaly, indicating that the shearing mechanism was propagating far in advance of the thermal front.

The proposed mechanism is a low-angle thrust fault triggered by a combination of an increase in σ_H (σ_1) and a reduction in the effective stress across the plane because of the high injection pressures. Because the fracture plane was undoubtedly a plane of complete parting ($p_{inj} > \sigma_v$), all natural-shear stresses had to be concentrated at the advancing tip of the parting plane, generating an in-line shear plane that propagated well in advance of the actual plane of parting (as sketched in Fig. 7).

Mitigation attempts, including double-walled high-strength casing with annular high-strength cement, generally were not effective. Later attempts included steam injection at the interface to soften the strata, but explicit data on the success of these measures is not available.

Cold Lake Thermal Well Shearing

Massive, heavy-oil (<10°API) reserves are exploited in the Cold Lake oil sands area of eastern Alberta, Canada, using cyclic steam

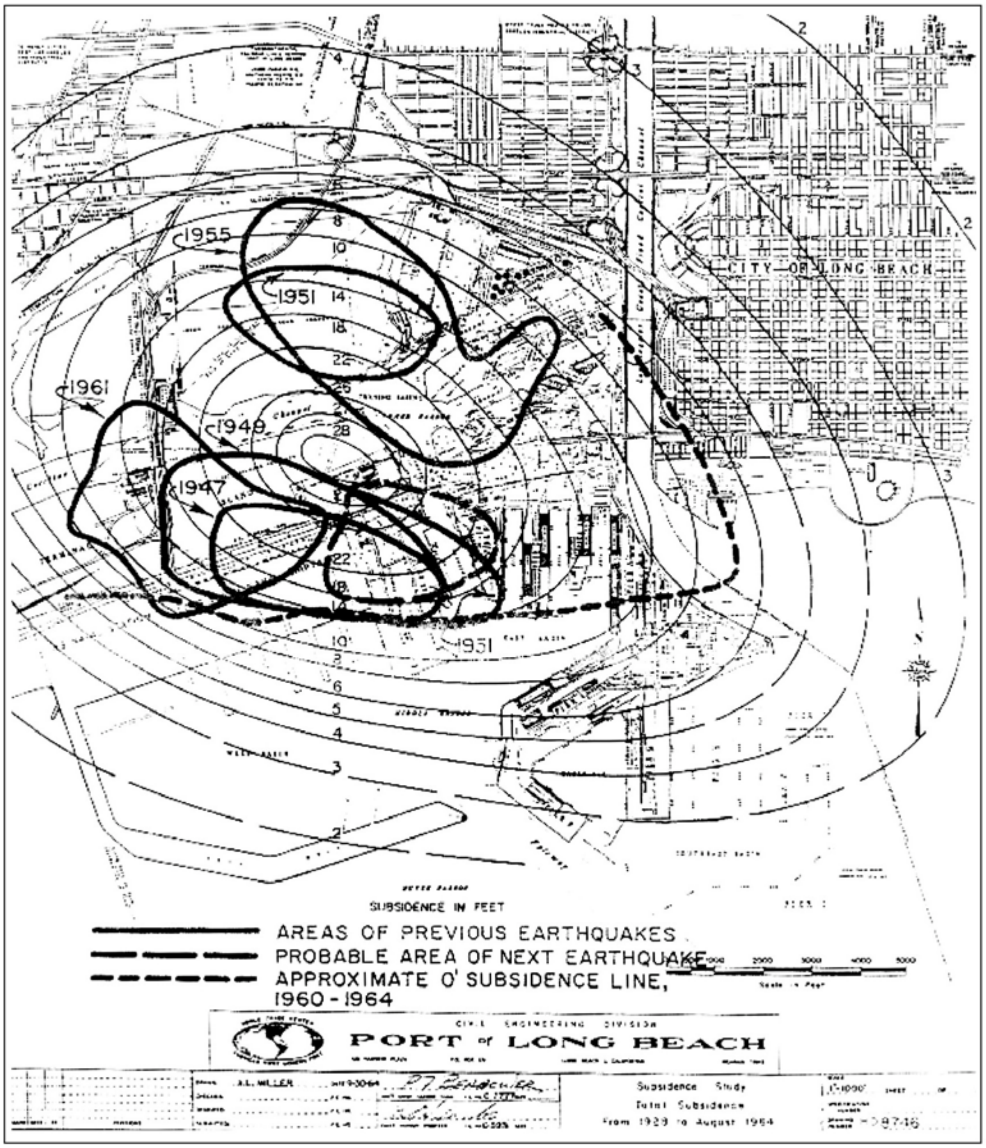

Fig. 13—Subsidence contours and shear areas in Wilmington field, Long Beach, California.

injection. The 30- to 50-m thick, 30 to 32% porosity arkosic Cold Lake oil sands are found in a single reservoir at a depth of approximately 450 m in the Clearwater formation of the Cretaceous Mannville group. Overlying the Clearwater formation is the sand-shale Grand Rapids formation, which is overlain by the smectitic marine shales of the Colorado group of Upper Cretaceous age. The lithostratigraphy is similar to that shown in Fig. 15, although thicknesses and depths are different.

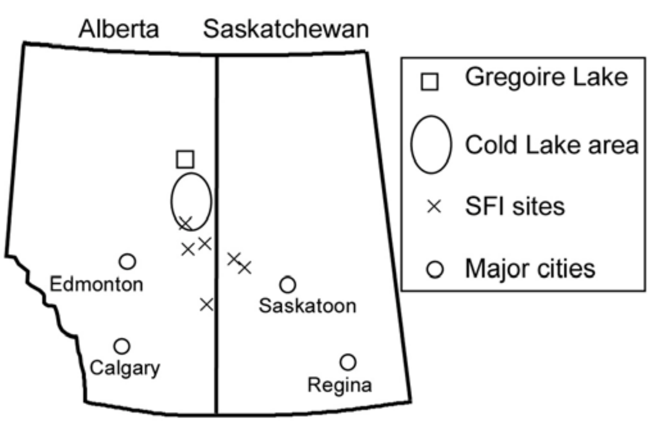

Fig. 14—Location of Canadian well shear examples.

In the cyclic-steam approach, the same wellbore is used for both steam injection and oil production. Downhole well spacing is 4 acres on a 1.7 aspect ratio (approximately 170×100 m per well), and wells are drilled from pads usually containing 20 wellsites. A typical well will go through 10 or more injection/production

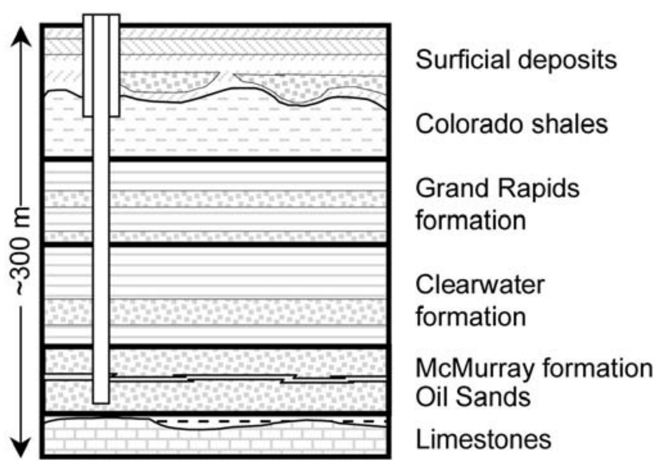

Fig. 15—Approximate stratigraphy, Gregoire Lake.

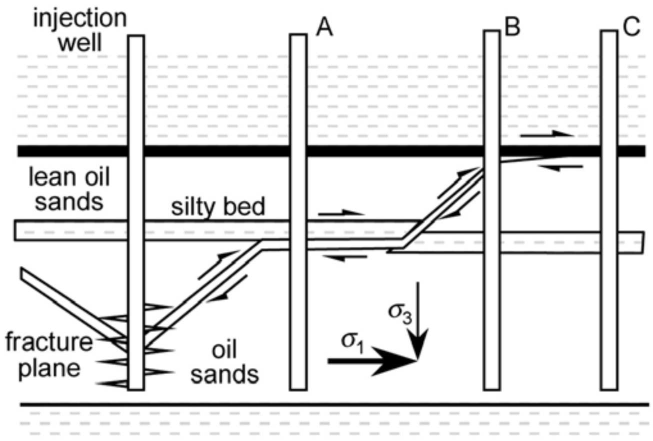

Fig. 16—Sequential fracture-induced casing shear.

cycles, each lasting several months. The cased well is exposed cyclically to fracture-injection pressures up to 10 to 12 MPa and temperatures up to 325°C.

More than 250 wells have failed at the Cold Lake heavy-oil field. Well failures have occurred at the top of the producing interval, at a shallow shale interval in the overburden, and near the base of the Colorado shale. Inclinometer surveys indicate localized shear displacements on weak bedding planes on the order of 100 mm and in some cases larger than 200 mm near the top of the producing interval. These arise because of pressure and thermally induced expansion and contraction of the oil sands (Figs. 6 and 9). Failures higher in the overburden occur by slip along weak bedding planes because of cyclic reservoir heave and compaction (Fig. 5).

When the reservoir is steamed, it expands in all directions as fluids are injected into the sand matrix. Uplift or "heave" in excess of 500 mm is recorded at the surface, and the tendency for lateral movement is accommodated by bedding-plane slip.[14] Well damage from formation shear occurs primarily in two zones: uphole failures near the base of the Colorado shale layers, and downhole failures within the Clearwater oil sands and at the interface between the Clearwater and overlying Grand Rapids formations. As usual, slip occurs at interfaces where strain discontinuities develop, and along the weakest beds, again near interfaces, in uphole regions.

Many of the early failures could be ascribed to thermal stresses exceeding connection strength (threads popping), combined with sulfide stress cracking, and most failures occurred at a coupling in the upper part of the wellbore. Once a leak occurred, bedding-plane slip was facilitated by high-pressure fluid leakage into the strata from nearby wells. In several instances, a primary well failure, perhaps caused by corrosion, would occur on a pad; some weeks later, when cyclic steam operations were initiated in the deeper Clearwater formation, other wells at the same pad would be sheared at the same depth as the first well leakage.

About 85 to 90% of the downhole failures at Cold Lake, more than 200 wells, occured at the top of the producing interval at the interface with an overlying Grand Rapids shale stratum. These failures are a direct result of shear stresses generated by steam injection and production in the oil sands. The overlying strata are not pressurized or heated and resist the tendency of the injection zone to expand, resulting in shear at the interface. Shear slip in the opposite sense undoubtedly also occurs when the reservoir compacts during the production phase.

The wells at Cold Lake are fully cemented across the Clearwater/Grand Rapids interface and hence, cannot accommodate much shear displacement. Vertical deformations also can induce shear deformations on deviated wells. For the approximately 200 wells damaged at this interface, those oriented at angles greater than 30° from vertical have been observed to fail at twice the rate (normalized with respect to the number of wells at that deviation) as wells oriented at angles less than 30° from vertical.

The shearing damage to wells is localized, sometimes confined to only 50 to 100 mm of wellbore length. When a coupling is located within a meter of the shear zone, it acts as a weak link, and threads tend to pop.

Downhole integrity loss often can be repaired, but uphole shear failures at Cold Lake are serious events that could result in the release of fluids to the surface. These cannot be repaired, and the wells must be abandoned. Multiple uphole casing failures have caused the abandonment of an entire pad of wells resulting from destabilization of the shale zone where shear is concentrated.

Belridge, California: Diatomite Compaction

The Belridge field is located in the southwestern San Joaquin Valley, California, about 80 km west of Bakersfield. The field is about 18 km long and 2.5 km wide. There are two primary producing intervals in the field. The first is the shallow Tulare formation, comprised of unconsolidated to loosely consolidated sands about 100 to 180 m thick. Beneath these sands lies the Belridge diatomite at an average depth of 500 m with an average thickness of 300 m. The diatomite averages 52.8% porosity, is highly compressible, and is subject to fabric collapse; a consequence is massive reservoir compaction under pressure depletion, leading to compaction and surface subsidence.

Well damage in Belridge was first noted in 1983; since then, more than 900 wells have been damaged, peaking at more than 160 wells per year in 1988, and currently averaging about 20 wells per year.[8] The majority of well damage occurs within two zones, one near the top of the diatomite and the other approximately 120 m higher, located in a 12-m-thick shale bed between the upper and lower Tulare sands. Thermal operations within the Tulare D sands at Belridge also probably are contributing to casing damage in those zones.

Water injection has reduced subsidence from ~0.45 m/yr in 1987 to the current rate of about 0.03 to 0.05 m/yr. Although well damage has declined significantly, impairment continues at about 3% of active wells per year. Casing strategies have been implemented to mitigate well damage, including thick-walled casing, slip joints, underreaming, and reservoir pressure maintenance strategies.

The major improvements were associated with casing strategies that allowed more slip by increasing annular space between the casing and the production tubing, by underreaming the zone before casing placement, and by strengthening casing in regions where bending was observed. In the Belridge case, strengthening of casing is more likely to be successful in mitigating shear because the formation is extremely soft when remolded by shear, and the stronger casing allows plastic flow around the well.

Without presenting details, we note that casing shear has been common in other areas near the Belridge field, such as in the Lost Hills field diatomite, where there is also significant compaction and surface subsidence.

Alberta SFI™ Activity: Injection Shearing

Large-scale injection of waste oily sands, slops, and back-produced drilling muds through slurry injection at high pressures takes place in unconsolidated sandstones of 30% porosity in Alberta and Saskatchewan, Canada, (Fig. 14).[10,11] In some cases, more than 20 000 m^3 of sand have been injected as aqueous slurries of density 1.15 to 1.25 g/cm^3 over periods of many months at rates of 600 to 800 m^3/day (total slurry rates). Waste injection takes place at depths of 350 to 650 m in strata ranging from thick (40 m) quartzose sands to less thick (12 m), fine-grained arkosic sands with clay streaks. Despite generally trouble-free operations for many months, well integrity problems may develop occasionally.

The mechanism involved in loss of well integrity is apparently shear displacement, leading to loss of pressure integrity or to tubing pinching in the casing. The large volumes put into the sands causes slip in the reservoir shoulders, as in the case of compaction (Fig. 5), but in the opposite sense of motion. In the one case where the casing distortion was located precisely, it was apparent that the most "clayey" (and hence weakest) zone in the overburden, approximately 25 m above the target horizon, slipped laterally. The slip may have been helped by transmission of high pressures along the casing, reducing the strength in the zone that slipped, therefore the hydraulic seal of the well is an important issue.[15]

Other Cases of Formation Slip: Conditions

Casing shearing has been identified in many other cases, at various depths, and in reservoirs subjected to various extraction processes. It is possible to state a few generalities on the probability of formation slip leading to casing failure. We will differentiate between the two most important cases: shear at the top of the producing interval, and shear higher in the overburden. The latter is associated more generally with compaction, the former with thermal processes, although there is much overlap in the mechanisms, and there are other mechanisms and exacerbating conditions (pressure migration along casing, Euler buckling in the producing horizon, normal fault reactivation, etc.).

In general, overburden-formation slip leading to casing impairment is most likely to occur when the magnitude of compaction or heave is large; where there are large stiffness contrasts such as sandstone-shale interfaces; if the overburden has weak-shale bedding planes; and where the casing traverses the shoulders of the structure.

In the case of shearing at the upper interface of the reservoir, it appears that casing impairment in offset wells dominates and is more likely to occur when temperature changes are large in thermal projects; when pressure changes are large in injection or depletion projects; and if there is an impermeable barrier at the top retarding advective heat and pressure migration, leading to a shear-stress concentration along the interface.

In all cases, if the naturally occurring shear stresses are large (high $\sigma_1-\sigma_3$ values), if there are high natural pressures in the shale zones, or if there is transmission of high injection pressures to the susceptible zone by some means, shearing probability and magnitude will increase.

Clearly, we have not identified specifically all cases where casing shear can arise. In many other circumstances casing shear can occur, and we note a few that are worthy of consideration.

- Geothermal reservoir exploitation (large $-\Delta p$ and $-\Delta T$ lead to large $-\Delta V$).
- Massive cold water injection into hot reservoirs ($-\Delta T$ and increased pore pressure to reduce strength).
- Large-scale solids production as in cases of chalk and heavy-oil sand exploitation through cold production with massive sand ingress.[16]

Low-porosity cases or situations such as strongly cemented sandstone or carbonates tend not to evidence casing shear, despite the fact that numerical modeling shows that the magnitude of the shear stresses can be large. This is because there are strong cohesive forces that resist the tendency to slip and because the generally high stiffness tends to predicate against large volume changes under conditions of pressurization or depletion.

Cures for Casing Shear

Options for reducing the incidence of casing shear are limited to deliberate avoidance, strengthening of the casing, allowing more compliance between casing and formation, or reducing the magnitude of slip along planes. It is more realistic to apply several tactics simultaneously to reduce casing shear incidence and rate, rather than seeking to eliminate it.

Strengthening the Casing. Simulation results and field experience show that the strength of the casing-cement system is of little consequence in resisting shear displacement of strata. It is possible to make casings that have moments of inertia many times greater than conventional casing by using double-walled annuli filled with cement. In general, however, the size of the induced shear planes is so large (greater than thousands of square meters) that the presence of a "strong" casing cannot resist slip, only retard the process somewhat. The stiffer the casing-cement system, the more likely it is to focus (attract) stresses. Casing strengthening may be effective in cases where the slipping strata are highly porous, soft, and susceptible to plastic flow after fabric collapse, such as diatomite or chalk beds **(Fig. 17).** Note that if only a small plasticity zone is generated, casing collapse is inevitable. However, if the plastically flowing zone is large (or if the material porosity is very high), the well cross-section is less affected and the casing dogleg is distributed over a long section, allowing workovers and reducing casing thread popping.

Increasing System Compliance. If a stiff and resistant casing attracts stress and cannot resist the induced shear slip, it makes much more sense to increase the compliance of the wellbore-casing system so that it can distort over a greater length before collapsing or developing severe dogleg (Figs. 10 and 17). Options include the following.

- Avoiding cementing the susceptible zones or using an extremely ductile cementing agent that can "flow."
- Underreaming across the zone and avoiding cement.
- Increasing the casing size to allow more distortion before the tubing is pinched.
- Weakening or remolding the formation in the susceptible zone to allow more plastic deformation.

In each case, a larger amount of shear slip can take place before well function is impaired, as is evident from examining Figs. 3 and 10.

Avoidance of Slip Planes. It is possible to place wellbores in regions where the magnitude of shear slip is likely to be lower than other areas **(Fig. 18).** Given a production strategy (spatio-temporal drawdown distribution) and reasonable material parameters (stiffness, strength, and stratigraphy), numerical geomechanical modeling can be used to indicate where the shear stresses and slip are likely to be the greatest. Some suggested tactics include the following.

- In simple cases such as a rectangular or lenticular reservoir (Fig. 5), drill wells in the center.
- In flat reservoirs with thermal or high-pressure processes as illustrated in Figs. 6 and 9, avoid inclined wells that may intersect high-shear zones.

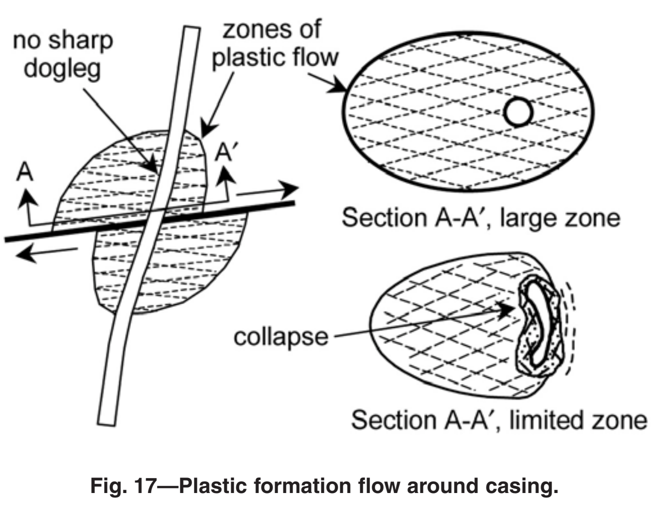

Fig. 17—Plastic formation flow around casing.

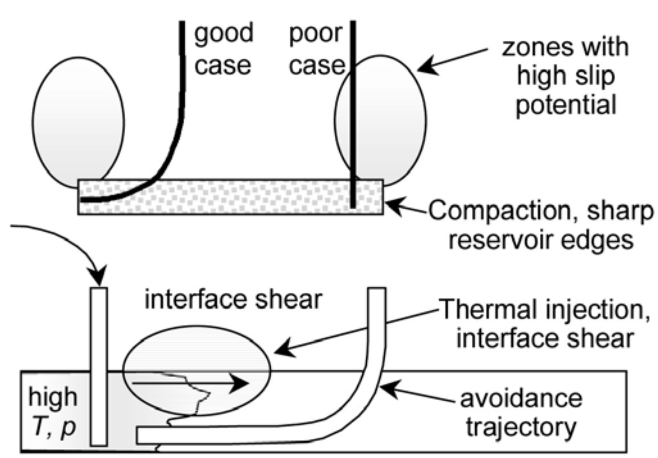

Fig. 18—Avoidance of zones of maximum slip.

• Avoid locations that will be intersected by steep thermal gradient fronts such as advective thermal fronts or boundaries between advective and conductive zones.

• In cases of strongly anisotropic horizontal-stress fields, adjust well spacing in the most optimum direction commensurate with the process being employed.

• Use short-radius or long-reach wells to avoid intersecting regions of greatest slip (Fig. 18).

• Orient horizontal wells parallel to the potential slip surfaces to increase chances of avoidance.

Three-demensional geomechanical modeling will be necessary to optimize well locations, and it is recommended strongly that a microseismic monitoring program be implemented to confirm and further optimize the design during operations.

Reducing Formation Slip. In the case of compaction, slip magnitude is proportional to compaction magnitude, and any means of pressure maintenance that reduces compaction will lead to a reduction of shear slip along bedding planes in the overburden. Similar slip magnitude reduction efforts can be employed in other cases; some options include the following.

• Reduce the size of steam slugs in cyclic steam injection.

• Earlier implementation of pressure maintenance on all depletion-driven technologies.

• Use lower differences in pressure or temperature.

• Use more appropriate cements and better cementing approaches to reduce the incidence of leakage along casing.

Reservoir Stress Management. If a 3D geomechanical model can give realistic predictions of the shear stresses induced by a process, then the model can be used to investigate exploitation alternatives that may lead to lower shear stresses, as well as identify sites of least shear displacement. The model must be used in conjunction with a reservoir pressure evolution model and must be confirmed and calibrated with real data. Therefore, a few comments about monitoring are appropriate.[17]

Specific localization of shearing strata interfaces may be undertaken using microseismic monitoring, and this is strongly advised in cases where shear is likely to be an important factor. However, for microseismic emissions to occur, slip must occur; therefore, this is a tactic to use in ongoing reservoir stress management and cannot be an *a priori* avoidance method.

Precision permanent tiltmeters arrayed in shallow sites or deeper monitor wells will allow the deformation patterns to be analyzed quantitatively. In turn, this permits good calibration of the geomechanical model.

Casings penetrating zones that are known to be susceptible to shear should be surveyed periodically with multiple-arm calipers to obtain a 3D representation of the distortion. In turn, this gives insight into the direction of motion and the magnitude and rate of slip, allowing specific quantitative design decisions to be made for new wells or repairs.

Conclusion

Casing impairment through shear occurs whenever large induced stress changes occur in weak, stratified sediments. Thermal-stimulation cases and large compaction cases almost inevitably generate large numbers of casing-shear incidents. Casing shear may be linked also to reactivation of old faults, high-pressure injection, slurry-fracture injection, or massive solids production.

The lithostratigraphic conditions and initial stress state have a strong influence on the time of onset and magnitude of casing shear. Furthermore, combined with the reservoir geometry and the pressure history of the reservoir, these factors control which planes will shear, by how much, and when. The only way to quantify these factors is to make a commitment to 3D geomechanical modeling. Model results can be used to help decide drilling strategies and even timing of well placement in particular locations.

Reducing the incidence and rate of casing impairment through shear can be achieved through a number of tactics. Favored ones include avoidance of the most troublesome regions, increasing the compliance of the casing-wellbore system through susceptible horizons, and altering the process to reduce the magnitude of shear slip. In some cases, stronger casing may help, but only in those cases where the strata are exceptionally weak and tend to deform by general plastic flow. Geomechanical modeling is necessary to quantify all of these approaches.

Finally, the vital role of monitoring in the design process and reservoir stress management strategy must be revisited. Monitoring of data allows location of slip zones as well as assessment of direction of movement, rate, and magnitude of slip.[18] Deformation data allow models to be calibrated, increasing their utility as management tools.

Nomenclature

c' = cohesion of the rock
E = Young's modulus
k = permeability
p = fluid pressure
Δp = change in pressure
p_{inj} = injection pressure
p_o = initial or in-situ fluid pressure
ΔT = change in temperature
ve = positive
V = volume
ΔV = change in volume
V_{inj} = volume injected
V_{prod} = volume produced
σ' = effective stress
$\Delta\sigma$ = change in stress
σ_h = smaller horizontal stress
σ_H = larger horizontal stress
σ'_n = effective stress normal to a slip plane
σ_r = radial or outwardly directed stress
σ_v = vertical stress
σ_1 = major principal stress
σ_2 = intermediate principal stress
σ_3 = minor principal stresses
σ'_{ij} = general stress tensor
δ_{ij} = Kroenecker delta
τ = natural shear stresses
$\tau_{\max}$ = maximum shear stress in the Mohr-Coulomb slip criterion
$\phi'.$ = internal friction angle

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SPE 64733

Why Oilwells Leak: Cement Behavior and Long-Term Consequences

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Abstract
Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing. Assuming this hypothesis is robust, it must lead to better practice and better cement formulations

Introduction, Environmental Issues
This discussion is necessarily superficial, given the complexity of the issue and attendant practical factors such as workability, density, set retardation, mud cake removal, entrainment of formation gas, shale sloughing, pumping rate, mix consistency, and so on. A conceptual model will be developed in this article to explain slow gas migration behind casing, but we deliberately leave aside for now the complex operational issues associated with cement placement and behavior.

In 1997, there were ~35,000 inactive wells in Alberta alone, tens of thousands of abandoned and orphan wells[1], plus tens of thousands of active wells. Wells are cased for environmental security and zonal isolation. In the Canadian heavy oil belt, it is common to use a single production casing string to surface (Figure 1); for deeper wells, additional casing strings may be necessary, and surface casing to isolate shallow unconsolidated sediments is required. As we will see, surface casings have little effect on gas migration, though they undoubtedly give more security against blowouts and protect shallow sediments from mud filtrate and pressurization.

To form hydraulic seals for conservation and to isolate deep strata from the surface to protect the atmosphere and shallow groundwater sources, casings are cemented using water-cement slurries. These are pumped down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden (Figure 1). Casing and rock are prepared by careful conditioning using centralizers, mudcake scrapers, and so on. During placement, casing is rotated and moved to increase the sealing effectiveness of the cement grout. Recent techniques to enhance casing-rock-cement sealing may include vibrating the casing, partial cementation and annular filling using a small diameter tube.

Additives may be incorporated to alter properties, but Portland Class G (API rating) oil well cement forms the base of almost all oil well cements.[2] Generally, slurries are placed at densities about 2.0 Mg/m^3, but at such low densities will shrink and will be influenced by the elevated pressures (10-70 MPa) and temperatures (35 to >140ºC) encountered at depth.

The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on.

Methane from leaking wells is widely known in aquifers in Peace River and Lloydminster areas (Alberta), where there are anecdotes of the gas in kitchen tap water being ignited. Because of the nature of the mechanism, the problem is unlikely to attenuate, and the concentration of the gases in the shallow aquifers will increase with time.

This implies that current standards for oilwell cementing and P&A are either not well founded, or the criteria are based on a flawed view of the mechanism. This is not a condemnation of industry: all companies seek to comply with standards.[3] Nevertheless, we believe that the AEUB Interim Directive 99-03[4] is flawed with respect to gas leakage around casings. To rectify this, the mechanisms must be identified correctly. Practise can then be based on correct physical mechanisms, giving a better chance of success (though we do not believe that the problem can be totally eliminated because of the vagaries of nature and human factors, despite our best efforts).

There is also need for better quality oil-well cement formulations that can resist thermal shocking. For example, leakage of fluids along thermal wells in cyclic steam operations in Alberta has proven a challenging problem for Imperial Oil.[5] If poor quality or poorly constituted cement is used, high injection pressures, thermal shocking, plus non-condensible gas evolution lead to leakage behind the casing that could break to surface under exceptional conditions.

Finally, in production management for conservation purposes, zonal isolation is multiple-zone wells.[6]

There are initiatives to identify old leaking wells and undertake mitigating action in Alberta and Saskatchewan, the "orphan well" program of the AEUB, initiatives by the Petroleum Technology Alliance Centre in Calgary, and so on. This article is to try and clarify the mechanisms involved.

Cement Behavior

Cement Shrinkage: If cement is placed at too high a water content, it loses water to the porous strata under lower pressure (p_o) through direct filtration because the cement hydrostatic head is greater than the pore water pressure head. The annulus width between casing and rock is small (e.g. 175 mm casing in a 225 mm hole = 25 mm), so even a small shear strength development between rock and cement will support the weight of the cement. If this shear stress is only ~0.5 kPa, the entire "hydrostatic" head of the cement ($\gamma_c \cdot z$) can be supported by stress transfer to the rock mass. (Of course, because of temperature and pressure effects, this degree of set is not attained simultaneously along the entire cement sheath.)

Thus, while the cement is still in an almost liquid, early-set state, massive shrinkage can occur by water expulsion, but annular cement settling to compensate for the loss of water is impeded by the shear stress transfer to the rock mass. The consequence is shrinkage in the cement sheath.

Portland cements continue to shrink after setting and during hardening.[7,8] This autogenous shrinkage occurs because hydration reaction products occupy less volume than the original paste. Judicious proportioning control of the cement slurry and the use of admixtures and additives can limit the physico-chemical effects of the autogenous shrinkage processes. Mostly, the careful control of water content by using superplasticisers and the control of macro-shrinkage by using appropriate aggregates benefit the properties of the set grouts.

Silica flour (SiO_2, ground to –20 µm) is often used to make "thermal cement". It is added in quantities approaching 75% of the dry constituents, the remainder being cement powder. Silica flour has also been added to cement in an attempt to counteract shrinkage. Unfortunately, for physico-chemical reasons, silica flour can enhance both drying and autogenous shrinkage.[9]

Silica flour is a ground product, usually made from pure quartz sand. Physically, the silica flour, by virtue of its grain size ($D_{50} \approx$ 10-20 µm) has a large surface area; this provides not only enhanced reaction areas for kinetically controlled hydration processes, it provides a need for additional wetting for slurry formulation. Physico-chemically, a freshly fractured silica surface possesses a high chemical reactivity because of the presence of unsatisfied bonds arising from the breaking of the silica chemical lattice. These fresh surfaces will electrostatically bind polar water molecules to satisfy these broken bonds. Experiments on pure silica using magnetic resonance and dielectric permittivity show that up to 9-11 layers of water can be absorbed on the surface, and the closest layers are of course the most tightly bound.

The surface area increases inversely as the square of the mean particle diameter, therefore reducing the surface area by a factor of five (grinding 100 µm sand to 20 µm flour) increases the area by 25, and because the new surface area is chemically fresh, it is more reactive. Thus, the electrostatic bound water volume for silica flour is vastly larger than for geochemically "old" sand. Furthermore, electrostatically bound water thickness is reduced by temperature (Brownian motion), so cool slurry will have a surfeit of water when it becomes heated through contact with geothermal temperature.

Alternative fillers are required to control the macro-shrinkage properties of the materials. We recommend 60-100 µm quartz sand be substituted for SiO_2 flour when possible.

Other processes can lead to cement shrinkage. High salt content formation brines and salt beds lead to osmotic dewatering of typical cement slurries during setting and hardening, resulting in substantial shrinkage.[10,11] Experiments with recommended cement grout formulations placed against salt and potash strata clearly show massive dewatering of the cement and the formation of free brine at the interface between the cement and the salt. The same effect must occur when fresh-water cement grouts are in contact with low permeability rocks with highly saline pore fluids. By ensuring that the grouts are placed at high density, conducive to a stable grout microstructure, the effects of osmotic dewatering can likely be minimized, but this should be quantitatively assessed.

Recently marketed finely ground cements (Microfine™ and Ultrafine™) are Portland cement-based materials. They are generally finer than normal Portland cements and include pozzolanic additives, such as finely ground pumice. Slurries of these materials penetrate fine fissures and pores in rock more readily than more conventional grouts but in bulk suffer from very high shrinkage and, hence, without further modification, are not suitable for grouting the annulus between oil-well casings and the borehole wall.[12]

Dissolved gas, high curing temperatures, and early (flash) set may also lead to shrinkage. It is not clear if non-shrinkage additives have substantial positive effects at great depth and high temperature. These additives (e.g. Al powder) generally produce some gas, which in the laboratory provides volume increase. Additives may enhance some properties; however, they may induce negative impacts on other properties, or lose effectiveness at elevated temperatures, pressures, or in the presence of certain geochemical species. Also, autogeneous shrinkage continues long after these agents have acted.

Cement Strength and Rigidity. API standards for oilwell cement specify certain strength criteria. Strength is not the major issue in oil well cementing under any circumstances. Based on extensive modelling, cement clearly cannot resist the shear that is the most common reason for oilwell distortion and rupture during active production.[13] If compaction or heave (from solids injection) is taking place, the cement itself provides minimal resistance to buckling (compression) or thread popping (tension). If the annulus could be filled with relatively dense sand, the resistance to shear would be better than current ordinary oilwell cement formulations.

Based on over 50 triaxial tests at various confining stresses, we have shown that 28-day cured oilwell cements are contractile (volume reduction during shear) at all confining stresses above 1 MPa (150 psi). This is also the case for 70% silica flour cements, and for the new products based on extremely finely ground cement. (Specimens were cured under water at 20°C or at 90°C.) However, dense concretes used in Civil Engineering are dilatant, and therefore resistant to shear, at all working stresses.

The stiffness modulus of typical oilwell cement is small compared to that of low porosity rocks, and vastly lower than that of steel.[14] The stiffness moduli are roughly 2-4% that of steel, though there is a wide range depending on density, content, and confining stress. Depending on depth (~stress) and induration (~porosity), rock moduli may vary from 2% to 50% of steel, and a reasonable value is 5-15% in most intermediate cases of moderate porosity (10-20%).

Bond. Cement will not bond to salt, oil sand, high porosity shale, and perhaps other materials. Also, bond strength (i.e. the tensile resistance of the cement-rock interface) is quite small; in fact, the tensile strength of carefully mixed and cured oilwell cement at recommended formulations is generally less than 1-2 MPa. Given that fluid pressures of 10's of MPa may have to be encountered, given that pressure cycling of a well can easily debond the rock and cement (there is strain incompatibility because of the different stiffnesses), and given that de-bonding is generally a fracturing process with a sharp leading edge rather than a conventional tensile pull-apart process, a large cement bond to rock cannot be assumed in any reasonable case. Initiation and growth of a circumferential fracture ("micro-annulus") at the casing-rock interface will not be substantially impeded by a cohesive strength at this interface.

The presence of "good bond" on a cement bond log is in fact not an indicator of bond, but an indicator of intergranular contact maintained by a sufficient radial effective stress. The lack of bond on a bond log is actually evidence of the inability to transmit high frequency sonic impulses because of the presence of an "open zone", that is, a circumferential fracture that is open by at least a few microns. Thus, maintaining "bond" actually means maintaining effective radial stress. Note that if effective radial stress cannot be maintained, then hydraulic fracturing conditions must exist at the interface.

The Gas Leakage Model

A good conceptual model must explain the following typical aspects of oilwell behavior that are observed in practice.

- Generally there are no open circumferential fractures detectable after a typical good quality cement job ("good bond" is observed on the log traces).
- Such fractures develop over time and with service.
- Even in cases where bond appears reasonable over substantial sections of the casing, gas leakage may be evidenced some years or decades later.
- The process is invariably delayed; thus, there must be physically reasonable rate-limiting processes.
- The gas often appears at surface rather than being pressure injected into another porous stratum encountered in the stratigraphic column.
- The presence of surface casing provides no assurance against gas leakage.

Whereas we do not deny that mud channeling, poor mud cake removal, gas channeling, and so on can occur in isolated cases, we believe that a better hypothesis exists to rationally explain the points listed above.

Figure 2 shows the effect of shrinkage on near-wellbore stresses. (Plots are qualitative, but have been confirmed by numerical modeling, to be published later.) Initially, cement pressure $p_c(z) = \gamma_c \cdot z$, almost always higher than p_o, but lower than σ_{hmin} (lateral minimum total stress). Set occurs and a small amount of shear stress develops between the rock and the cement; then, hydrostatic pressure in the cement is no longer transmitted along the annulus. Thereafter, even minor shrinkage (~0.1-0.2%) will reduce the radial stress ($\sigma_r = \sigma'_r + p_o$) between cement and rock because rock is stiff (4-20 GPa for softer rocks), and small radial strains (0.001-0.003) cause relaxation of σ_r and increase in σ_θ. A condition of $p_o > \sigma_r$ (σ_3) is reached; i.e. the hydraulic fracture criterion. A circumferential fracture (i.e. $\perp$ to $\sigma_3 = \sigma_r$), typically no wider than 10-20 μm, develops at the rock-cement interface.

A thin fracture aperture is sufficient to appear as "loss of bond" in a geophysical bond log. Because in situ stresses are always deviatoric (e.g. $\sigma_{hmin} \neq \sigma_{HMAX}$), bond loss will usually appear first on one side of the trace, or on two opposite sides (direction of σ_{hmin}). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m.

A zone of $p_o > \sigma_r$ (σ_3) can extend for considerable heights. Nevertheless, this is still not a mechanism for vertical growth. To understand vertical growth, consider Figure 3, where a hypothetical case is presented. The static circumferential fracture of length L is filled with formation water of density γ_w, giving a gradient of about 10.5 kPa/m for typical oilfield brine, but the gradient of lateral stress ($\partial\sigma_h/\partial z$) is generally on the order of 18-24 kPa/m. This means that if the fracture contains a fluid pressure sufficient to just keep it open at the bottom, there is an excess pressure at the upper tip equal to ~L·(21-10.5) ≈ about 10 kPa/m, in typical Alberta conditions, for example. Thus, because of the imbalance between the pressure gradient in the fracture and the stress gradient in the rock, an inherent fracture propagation force is generated that tends to drive the circumferential fracture upward. (In a perfectly horizontal section, this cannot happen, but the process develops equally at higher elevations in the well where it becomes inclined.)

Now, consider what happens when a circumferential fracture between the cement and the rock is exposed to a thin stratum that contains free gas (there are invariably several such zones in any well). Cementing a casing leads not only to the development of a cement sheath, but the cement paste also slightly penetrates the interstitial space in the surrounding rock (a few grain diameters deep for typical sandstone). This reduces the permeability substantially, and because of capillary exclusion effects associated with two-phase flow and the reduced pore throat diameter arising from cement particle invasion, gas flow into the circumferential fractures is almost certainly through diffusion. This means that when the fracture is small, the rate of gas influx is modest. However, as the fracture grows in height, the contact area with surrounding sediments increases, and eventually (and particularly when the pressures are being reduced by surface leakage or flow into a higher stratum), the gas diffusion rate is large enough to lead to continuous but slow gas leakage.

In the fracture, once solution gas saturation is achieved, free gas at the top of the fracture develops. The gradient in gas is less than 1 kPa/m (rather than ~10.5 kPa/m for water) so there is an even greater excess driving pressure at the upper tip. In addition, this gradient effect tends to favor driving the liquid in the fracture back into the formation, albeit slowly, and the fracture becomes more and more gas-filled. Thus, there is a self-reinforcing process: the greater the vertical height of the fracture, the greater the excess driving force at the tip. The fracture grows vertically upward, and eventually leads to gas leakage behind the casing at the surface. It will migrate up around the outside of any casing strings at higher elevations because the excess pressure that can be developed at that stage is large enough to fracture even excellent bond (Figure 4). However, why does it take so long for the gas to get to surface (sometimes decades)?

Gas must migrate to surface through a circumferential fracture perhaps only 10-20 μm thick extending over only a limited part of the circumference of the rock-cement interface. Note that fracture aperture develops between p_f and σ_r (= σ_3) when the pressure acts to maintain it open, but because the rock and cement have elastic stiffness, they act to severely restrict the aperture. Thus, there are at least two rate-limiting aspects to gas evolution at the surface: diffusion rate of gas into the fracture, and the low "hydraulic conductivity" of the circumferential fracture arising because of its narrow aperture.

Why does the fracture grow so slowly? When the micro-annular circumferential fractures are not connected and are short, the excess pressure at the tip is small. Also, if the casing pressure is large because of production pressure, this leads to a small outward flexure that may be enough to maintain the fissures closed. (Note that if a "better" bond log response is desired, simply pressurize the casing as the bond log is run!) As the production pressure declines with time, the fissure will tend to open more because the casing is less pressurized. Also, fracture growth in the vertical direction is undoubtedly aided by pressure and thermal cycles.

Nevertheless, it is common for gas bubbling at the surface to be noticeable only years and sometimes decades after P&A. Over time, the effective fracture length increases, and this leads to the driving pressure increase discussed above. Because the velocity of a fracture is a very strongly non-linear process that is positively coupled to the driving pressure, it probably takes years for diffusion processes to lead to a condition where growth starts to accelerate. However, once acceleration begins, the fracture length increases, and complete upward propagation is fast (days? months?), limited only by the rate at which fluids can enter the fracture at depth and flow to the tip. Thus, before P&A, a cement bond log may show that the well is in good condition, yet this is no guarantee that, years later, leakage will not occur.

As the fracture rises, the condition that the pressure in the fracture exceeds the pore pressure in the surrounding strata will arise. This will lead to flow from the fracture out into the strata. If this flow is unimpeded, it will occur and the fracture vertical growth will terminate. Now, a condition exists where gas and liquids are entering the wellbore region behind the casing and leaving it at a higher elevation. This is a loss of zonal seal, and could have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination. It can also have positive environmental effects, properly executed.

Yet, despite the existence of permeable zones, gas is still observed at the surface, and also as deep-sourced gas in shallow groundwater aquifers. The reason is probably that the cement paste in the pores of permeable strata acts to exclude gas by capillarity effects along the entire length of the stratigraphic column (it takes a large Δp to overcome surface tension effects in small pores). This means that gas must leave the fracture mainly by liquid-phase diffusion. So, it seems that in leakage cases the flow rate from depth simply exceeds the diffusive bleed-off rate at higher elevations, leading to the excess appearing at the surface. An interesting chromatographic effect probably occurs with mixed gases; because of differing pressure solubility, more soluble gases will diffuse into adjacent strata more rapidly, and the least soluble, CH_4, will arrive at the surface almost pure.

Unfortunately, even if no gas appears at the surface, it is no guarantee that the well is not leaking. In fact, the common occurrence of household water sources being charged with deep-sourced gas is clear evidence that there are many cases of leakage where the gas simply enters the water aquifer, and may never bubble around the casing.

Discussion

The hypothesis satisfactorily explains the phenomena associated with well behavior. Thus, it leads to a number of approaches to solve the problem. Eliminating cement shrinkage is one, but there are other practical solutions that are workable.

Cement shrinkage study and the development of new cement formulations that have no Portland phase[15] is an ongoing part of an industry-sponsored project, and new formulations will be available soon. Better recommendations for P&A are also being developed. These will be the subjects of other articles. This section will present an approach to environmental protection that can be operationally implemented at present.

Given that gas leak-off by Darcy flow (rather than diffusion) is likely impeded by the cement paste in the pore space of adjacent strata, one approach to environmental protection is to complete a well in the manner sketched in Figure 5. The open, non-cemented section is deliberately chosen to be across beds of sufficient permeability so that when excess pressure develops in the zone, the capillary exclusion effect can be overcome (less than 1 MPa typically, but depending on grain size and clay content). Because the rate of gas entry and transmission through the circumferential fracture is small, a permeable bed just a few 10's of centimetres thick will suffice to act as a drain. This bed will accept sufficient volumes of gas, and providing that it is laterally continuous, will act as a drain for a very long time, perhaps indefinitely.

Is there a need to revisit API standards on cement formulation, placement and completion practices, and industry quality control during placement?[16,17,18] We believe so, but this is a substantial issue, and specific suggestions await more results.

Closure

The elements of the gas leakage mechanisms that we propose are the following:

- Various mechanisms, but mainly cement shrinkage, lead to a drop in radial stress.
- When $\sigma_r < p_o$, a circumferential fracture will open.
- Differences between lateral stress gradients and pressure gradients provide forces for vertical growth.
- The excess pressure that develops at the upper leading tip increases as the (vertical) height.
- The fracture will tend to become gas filled as gas slowly diffuses into it, increasing the driving force.
- Fracture aperture is severely limited by the stiffness and geometry, limiting the upward propagation rate.
- Pore blockage because of cement paste penetration limits gas leak-off rates to those associated with diffusion because of capillarity effects.
- Eventually the fracture will rise, and gas will enter shallow strata or leak at the surface.

This working hypothesis has led to recommendations on cementing and casing strategies, and the pursuit of a cement formulation that can be easily placed yet not shrink is important, both for primary cementing, and for P&A.

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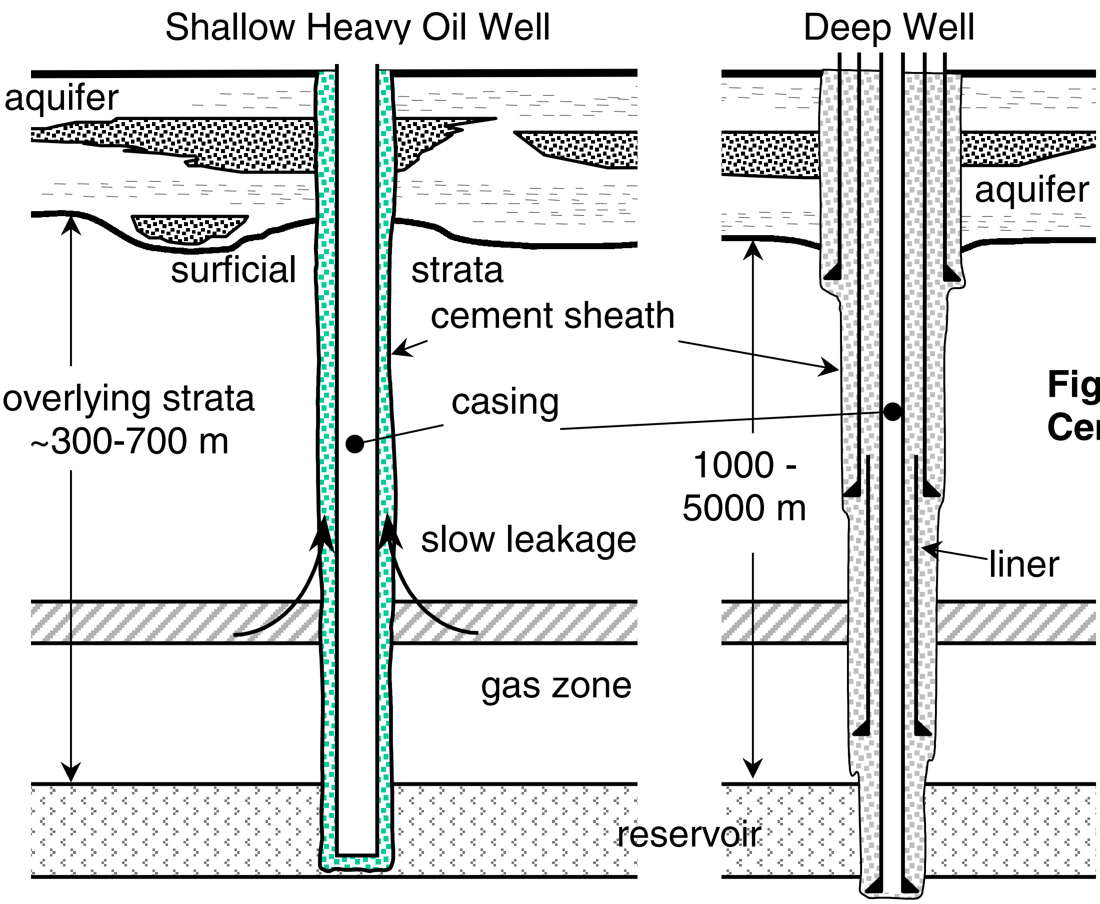
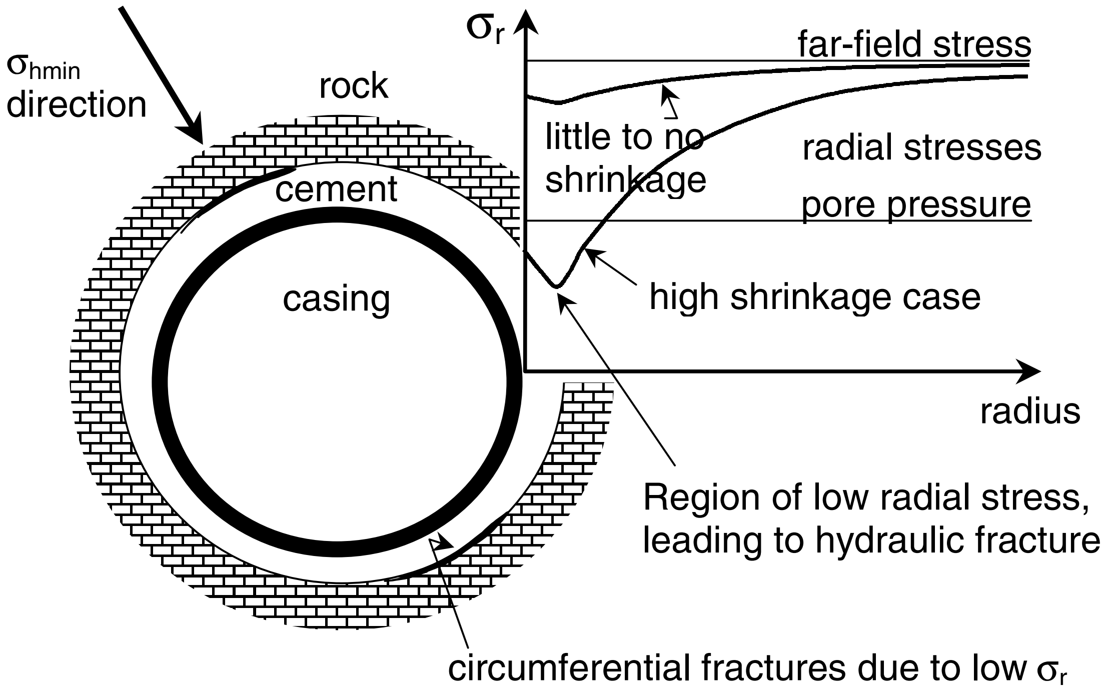


Figure 1: Cased, Cemented Wells

Figure 2: Radial Stresses and Circumferential Fractures



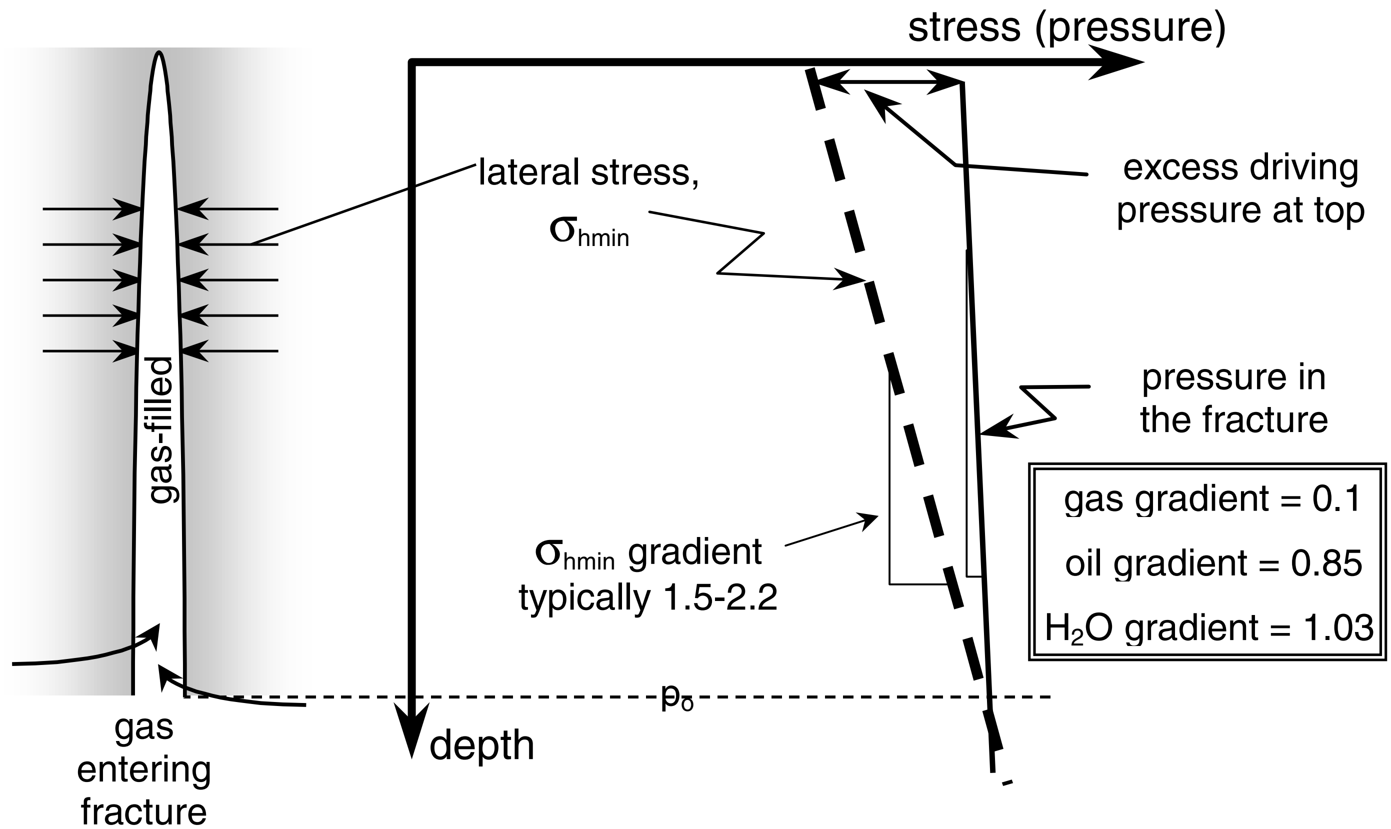


Figure 3: Fracture Driving Pressure from Gradient Differences

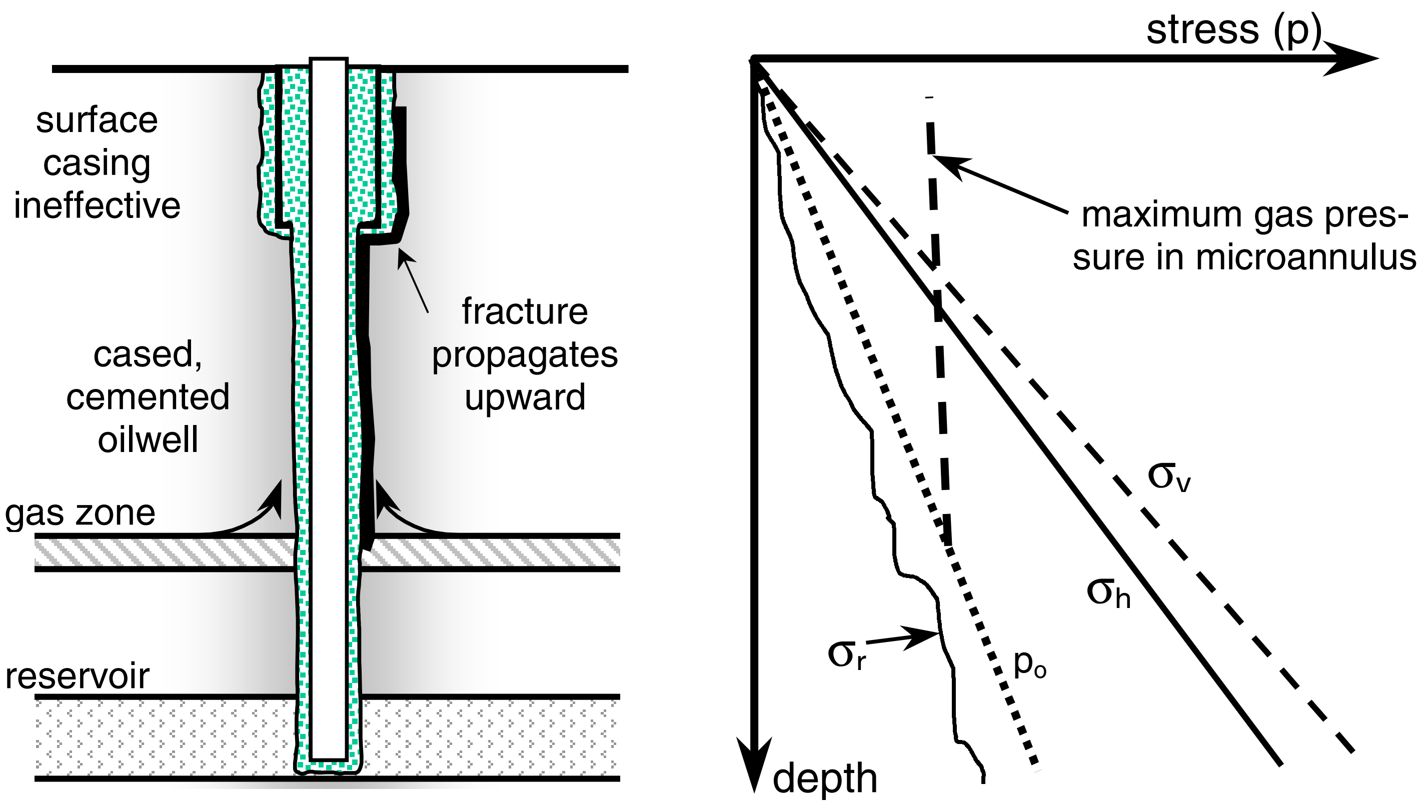


Figure 4: Fracture Approaching Surface

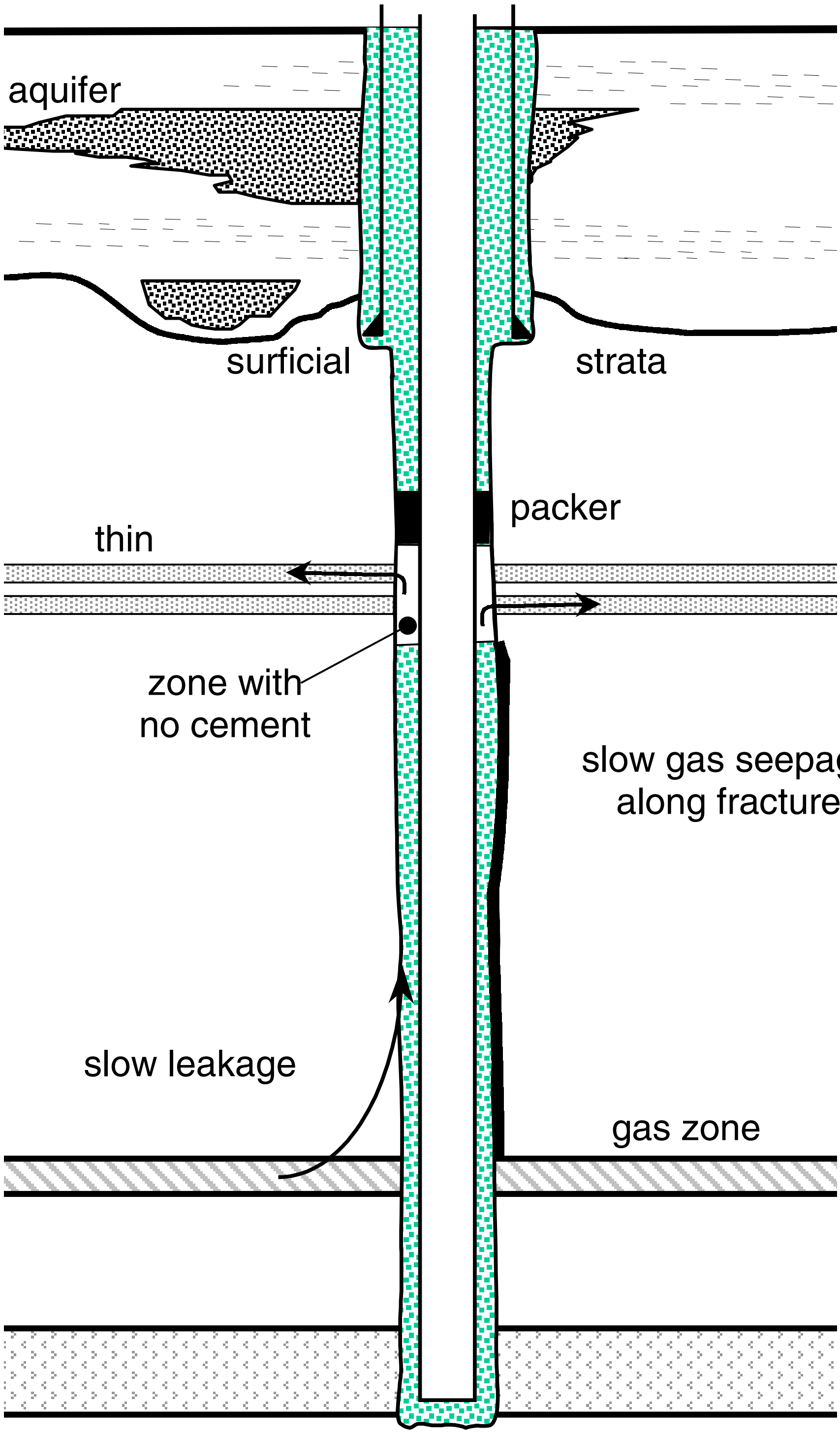


Figure 5: Leaving a Leak Off Zone to Arrest Gas Seepage

Marcellus Shale

Bill Wince, Vice President – Transportation & Business Development
Chesapeake Energy Marketing, Inc.

Chesapeake ENERGY

CHK Overview

- **The second largest producer of U.S. natural gas**
  - 4Q'09 natural gas production of 2.440 bcf/d
- **Most active driller in U.S. – CHK is responsible for 1 of 7 gas wells being drilled in the U.S.**
  - 118 operated rigs currently, down from 158 in 8/08 (~25%); ~70 non-operated rigs & ~15 info only rigs; collector of ~20% of all daily drilling information generated in the U.S. (~25% in our areas of interest); ~91% of our operated rigs are in the Big 6 shale and Granite Wash plays
  - It's a great time to drill, costs are down 20-25% from 2008 highs, plus JV carries go further in this lower cost environment
- **Consistent production growth – 20 consecutive years of sequential production growth**
  - Projecting increases of ~8-10% in 2010 and ~15-17% in 2011 to ~2.7 and ~3.1 bcfe/d, respectively (after curtailments and asset sales)
- **Best assets in the industry**
  - ~14.6 tcfe of proved reserves at 12/09, targeting 20-22 tcfe by 2012(1)(2)
  - ~65 tcfe of risked unproved resource potential (~177 tcfe of unrisked unproved resource potential) >10-year inventory of ~36,000 net drilling locations(2)
  - BP, PXP, STO and TOT JV's confirm asset quality directly; XOM/XTO and APC/MITSY confirms indirectly
- **Unparalleled inventory of U.S. onshore leasehold and 3D seismic**
  - 13.7 mm net acres of U.S. onshore leasehold and ~23.6 mm acres of 3D seismic data

Data above incorporates:
- CHK's Outlook dated 2/17/10
- Risk disclosure regarding unproved resource estimates appears on page 29

(1) Based on 10-Year average NYMEX strip pricing pro forma for Barnett JV; 14.3 tcfe at 12/31/09 using SEC pricing before Barnett JV
(2) As of 12/31/09, and pro forma for Barnett JV

CHK Overview, Continued

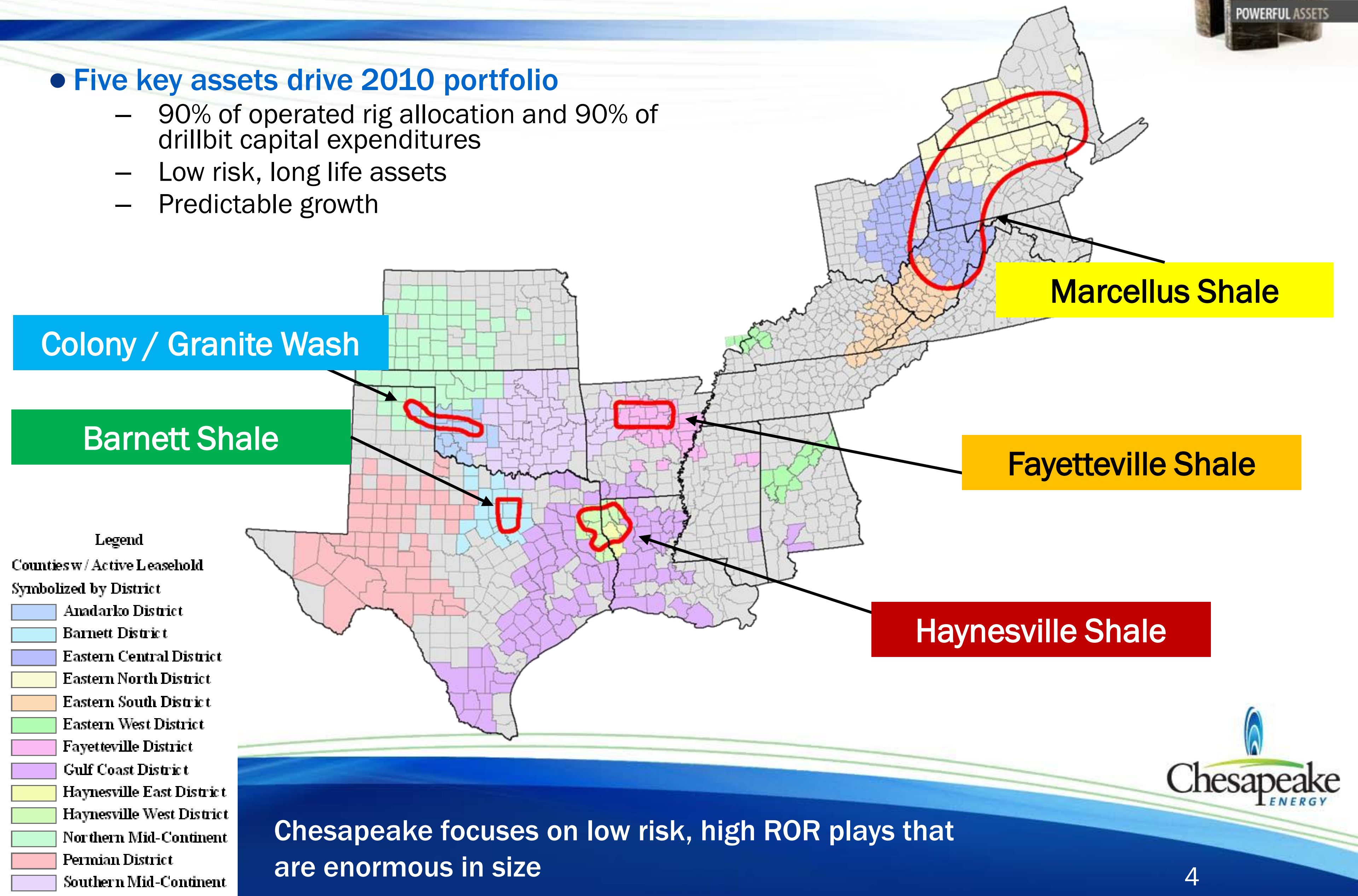
- **High quality U.S. shale asset base within the "Big 6"**
  - #1 in Marcellus Shale; ~1,570,000 net acres
  - #1 in Haynesville Shale; ~535,000 net acres
  - #2 in Fayetteville Shale; ~455,000 net acres
  - #2 in Barnett Shale; ~220,000 net acres (post Barnett JV)
  - #1 in Bossier Shale; ~180,000 net acres
  - Top-10 in Eagle Ford Shale; ~150,000 net acres(1)
- **Advantageous joint venture arrangements**
  - $10.7 billion of value captured vs. cost basis of $2.7 billion
  - $33 billion of remaining implied value based on JV terms
  - $3.4 billion of remaining joint venture carry receivables
- **Built-in finding cost advantages**
  - Able to add 2.0-2.5 tcfe per year of new proved reserves (after replacing production) at <$1.50/mcfe per year for years to come
  - Reserve maintenance cap-ex only ~25% of projected 2010 and 2011 operating cash flow
- **Substantial scale and vertical integration advantages**
- **Strong hedging track record**
  - ~$4.4 billion in realized gains 2001-2009

1) As of 2/17/2010

CHK has many unique competitive advantages in this tough economic environment – unmatched asset quality, high returns, low finding and operating costs, great hedges and world class JV partners

Focused on Low Risk, High ROR Plays

- **Five key assets drive 2010 portfolio**
  - 90% of operated rig allocation and 90% of drillbit capital expenditures
  - Low risk, long life assets
  - Predictable growth



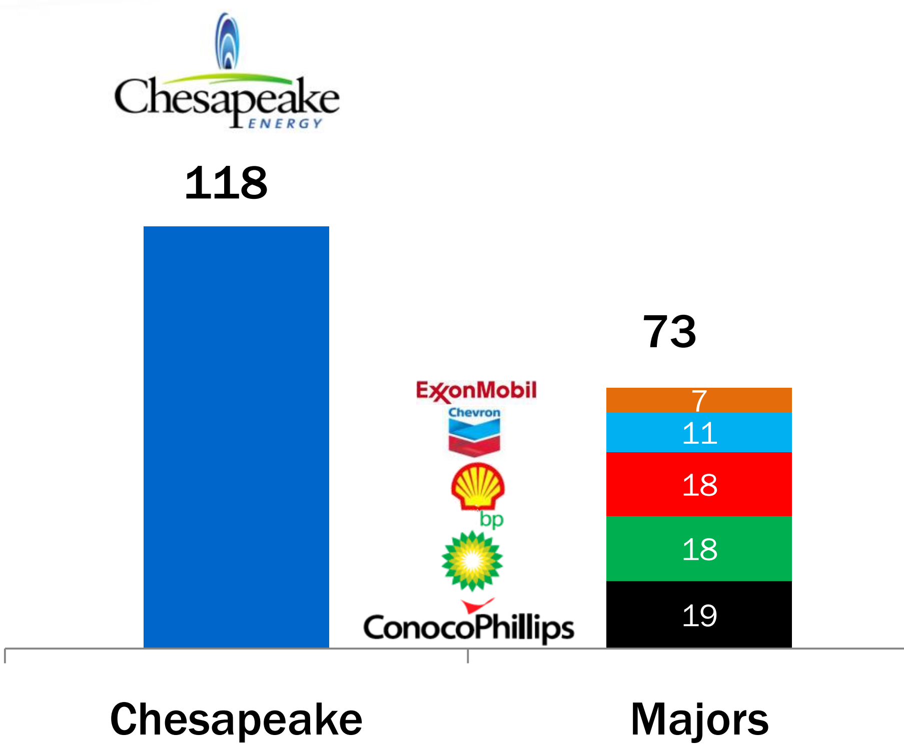
Chesapeake focuses on low risk, high ROR plays that are enormous in size

Independent Producers Leading the Effort

Top 10 Natural Gas Producers – U.S.

Rank	Company	Bcf/d	% of U.S. Production
1.	Exxon Mobil*	3.6	6.4%
2.	Chesapeake	2.4	4.2%
3.	BP	2.3	4.1%
4.	Anadarko	2.1	3.7%
5.	Devon	1.9	3.4%
6.	ConocoPhillips	1.8	3.2%
7.	EnCana	1.6	2.8%
8.	Chevron	1.4	2.5%
9.	Williams	1.2	2.1%
10.	EOG	1.1	2.0%
	Subtotal: Top 10	19.4	34.6%
	Rest of Industry	36.6	65.4%
Total		56.0	bcf/d

Chesapeake Operated Rigs vs. 5 Majors

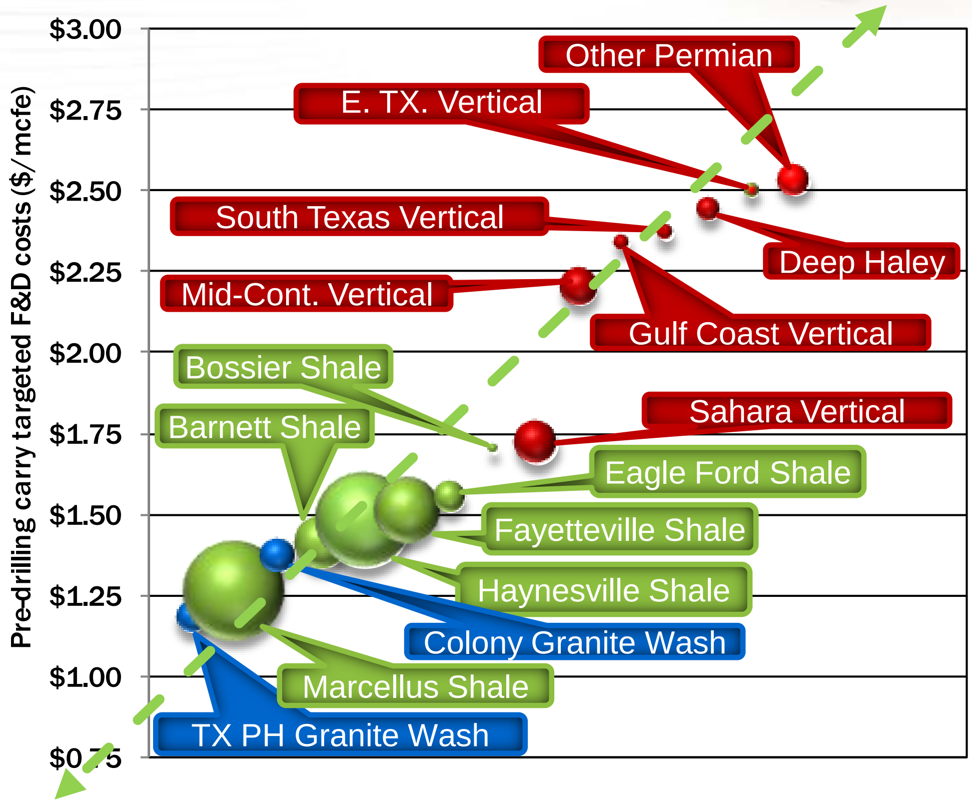


Source: Company reports as of 12/31/09 and Smith Tool 2/12/10

*Pro forma for the acquisition of XTO Energy

What is the Marginal Cost of Supply?

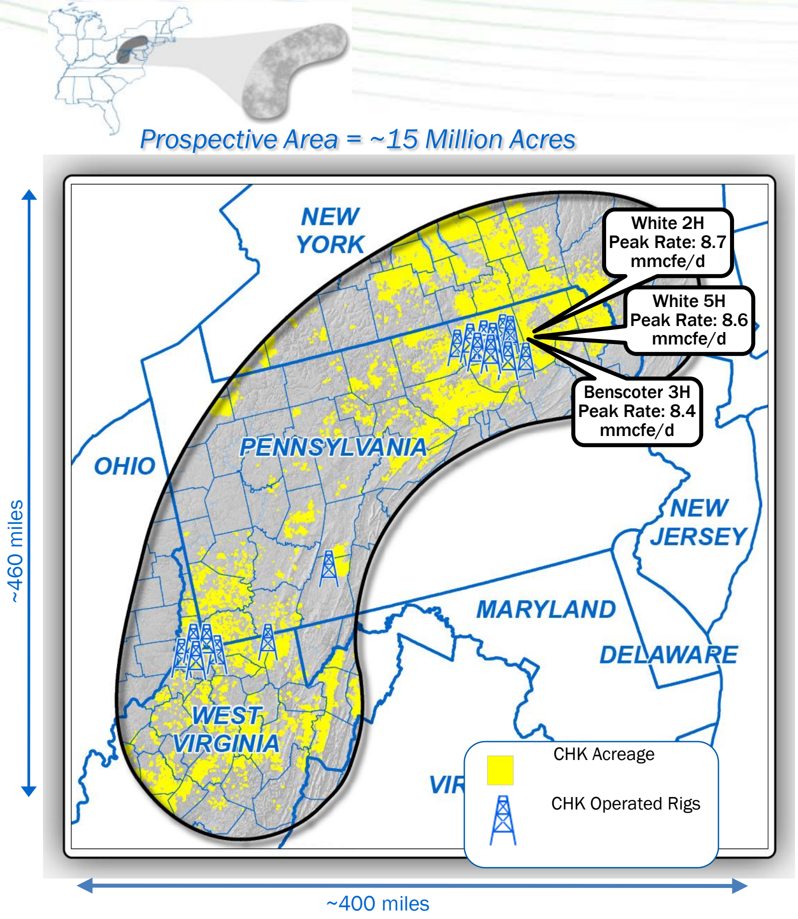
- **Natural gas prices not likely to stay permanently low because of the great success of the "Big 6" Shale plays**
  - Only 10-15 companies have captured meaningful positions in the plays
  - The remainder of the E&P industry is challenged to generate acceptable returns in higher cost, less-efficient plays
  - Greater bifurcation between the "shale haves" and the "shale have-nots"
    - The "shale haves" asset bases will continually improve while the "shale have-nots" asset bases will continually degrade
- **Marginal industry supply is determined by the highest cost one-third of U.S. production, not the lowest cost one-third**
- **Natural gas prices will ultimately rise to levels supporting drilling on higher cost assets and lead to strong margins in CHK's low cost shale plays**
  - A substantial majority of the ~85% of U.S. natural gas production that is non-shale needs $7-8/mcf NYMEX prices to be economically viable for enough drilling to stabilize declining non-shale production



(1) Size of bubble corresponds to relative size of CHK proved and risked unproved resources in each play

The Marcellus Shale

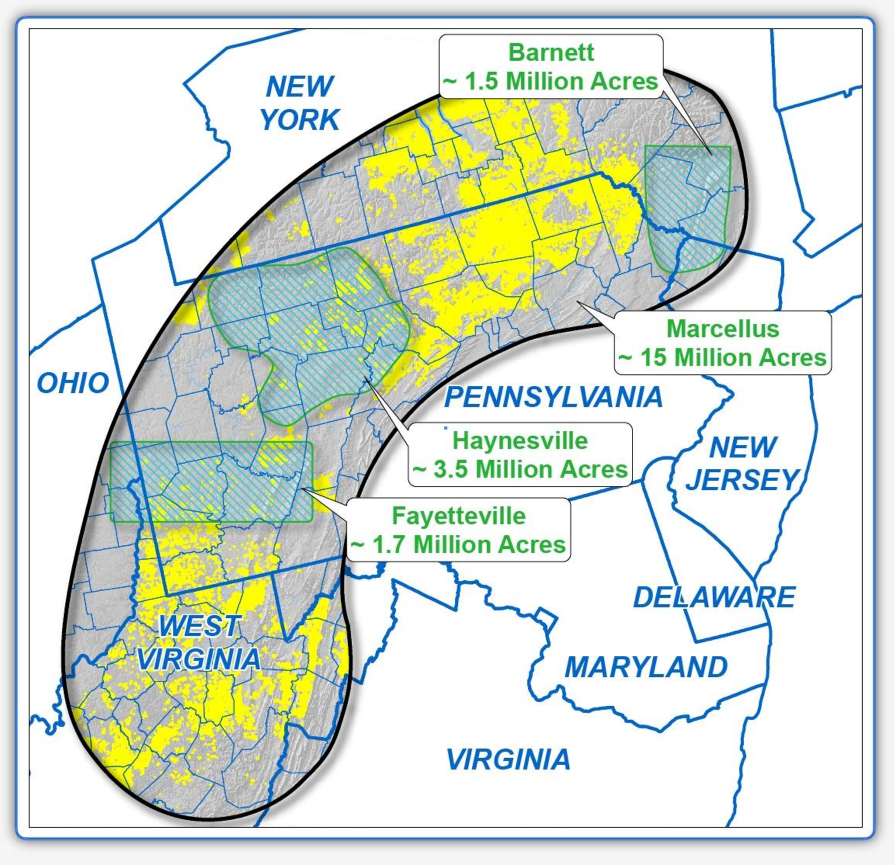
Marcellus Shale – Overview



- The Marcellus Shale play is likely to become one of the two largest gas fields in the U.S. (Haynesville the other)
- CHK is the second largest producer, the most active driller and the largest leasehold owner in the play with 1.6 mm net acres of leasehold
- 67.5/32.5 JV with Statoil (STO) in 11/08; $3.375 billion in cash and drilling carries
- Currently operating 24 rigs in the play; plan to average ~32 rigs in ’10 to drill ~175 net wells
- Anticipate net production reaching ~270 mmcfe/d by year-end ’10 and 450 mmcfe/d by year-end ’11
- After Statoil sale, CHK’s leasehold investment in the Marcellus is only ~$330/net acre on average, by far the lowest in the industry

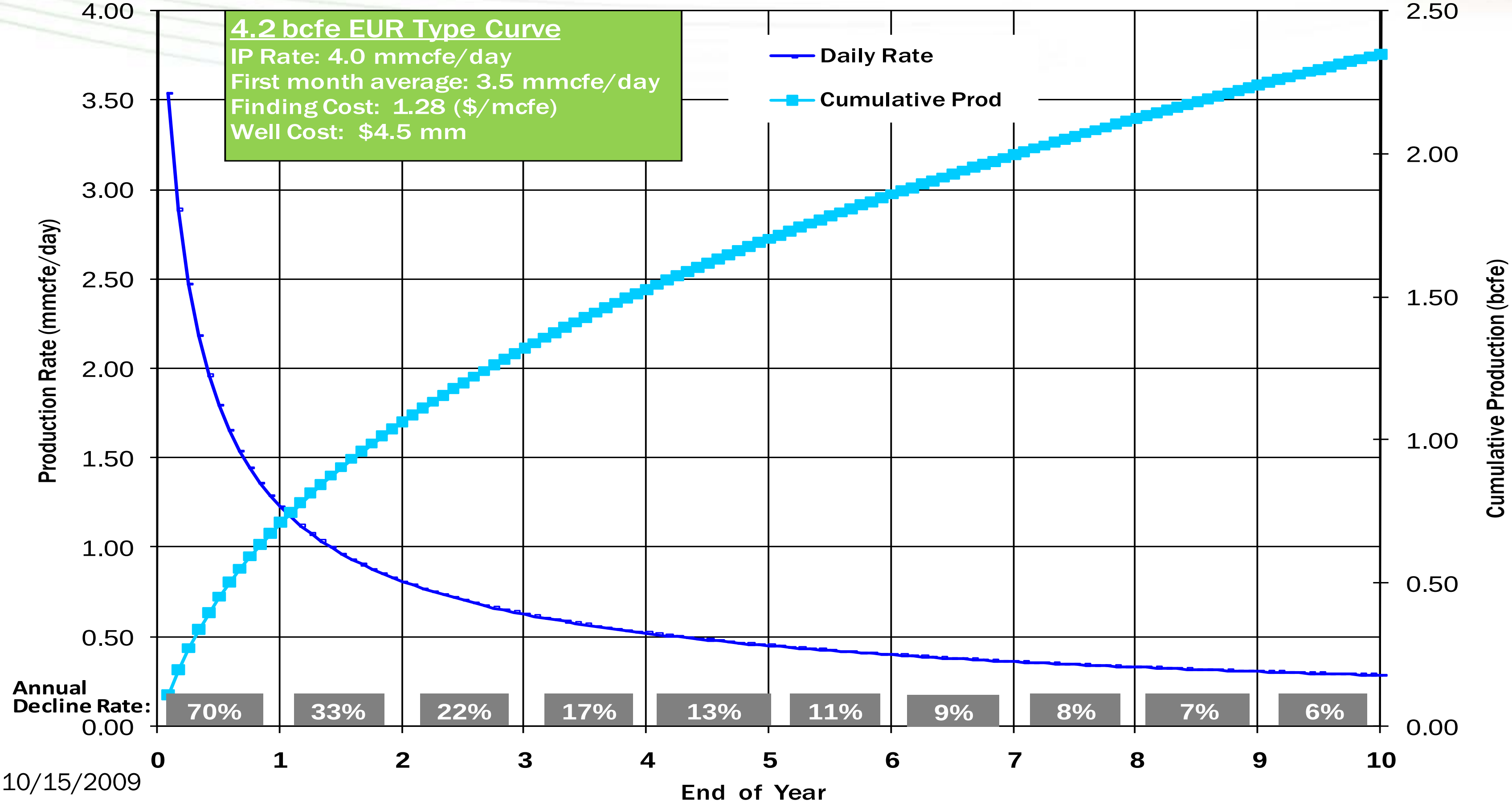
Marcellus Shale Potential – How Does it Compare?

- Marcellus fairway is larger than other Barnett, Haynesville and Fayetteville combined
- Marcellus has favorable depths, thickness, pressures and rock characteristics across large portion of basin
- Published estimates of ~489 tcf of potentially recoverable reserves from the Marcellus[1]
  - Haynesville - 250 tcf[2]
  - Barnett - 44 tcf[2]
  - Fayetteville - 42 tcf[2]
- Still in exploration and delineation phase
  - Gathering core and log data
  - High-grading leasing efforts
  - Drilling to retain acreage
  - Refining drilling and completion methods
  - Building gathering systems
  - Cataloging shallow and deep prospects



1) Dr. Terry Engelder - Penn State University
2) Modern Shale Gas Development in the U.S. A Primer – April 2009

Marcellus Shale – Targeted Horizontal Well Profile

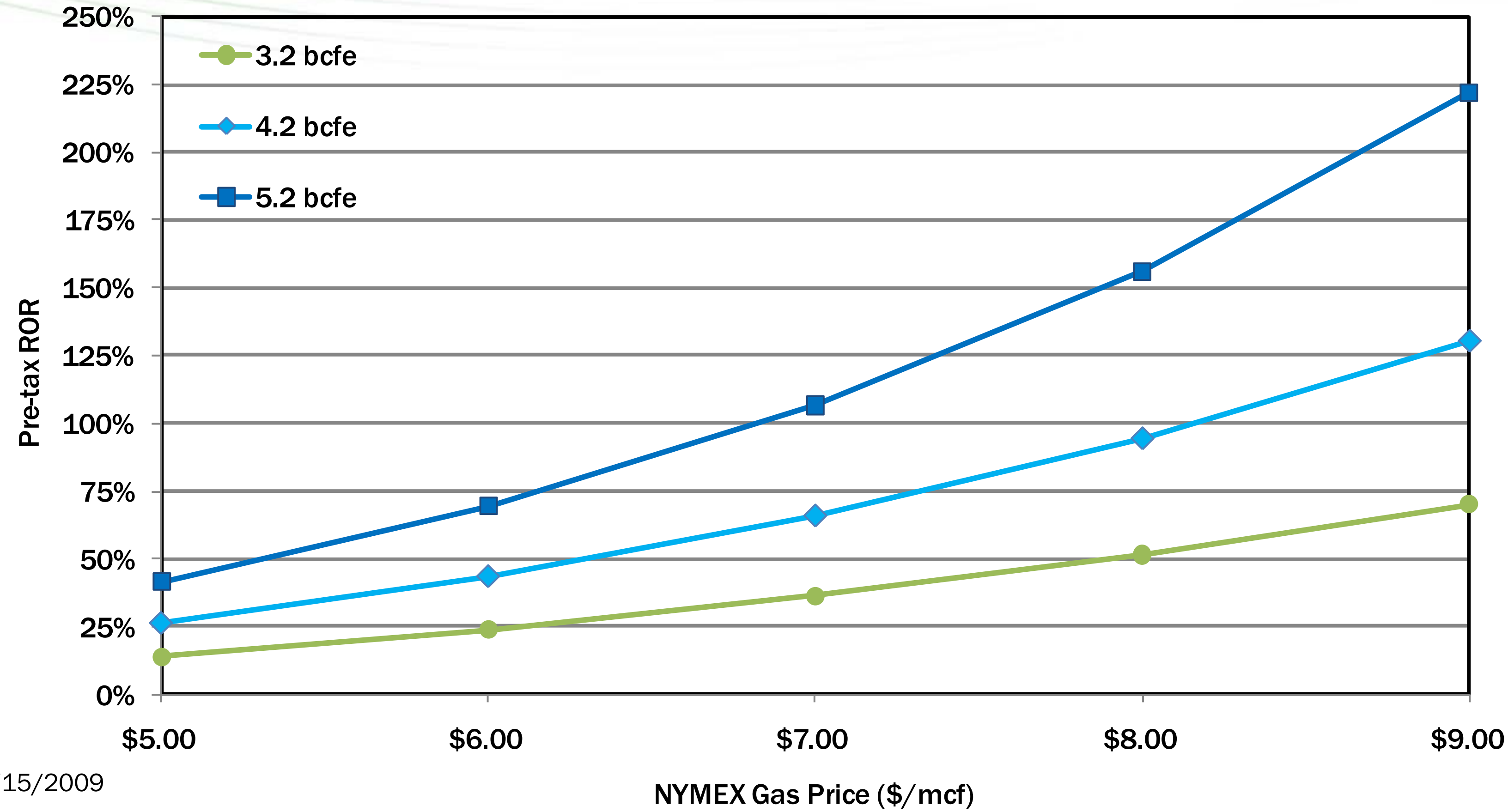


As of 10/15/2009

	CHK	Range	Ultra	Cabot	Talisman
IP	4.0 MMcf/d	4.9 MMcf/d[2]	7.5 MMcf/d[1]	6.9 MMcf/d[1]	4.5 MMcf/d
EUR	4.2 Bcf	3-4 Bcf	3.75 Bcf	5.5 Bcf	5 Bcf

[1] 30 day IP [2]Average Horizontal IP

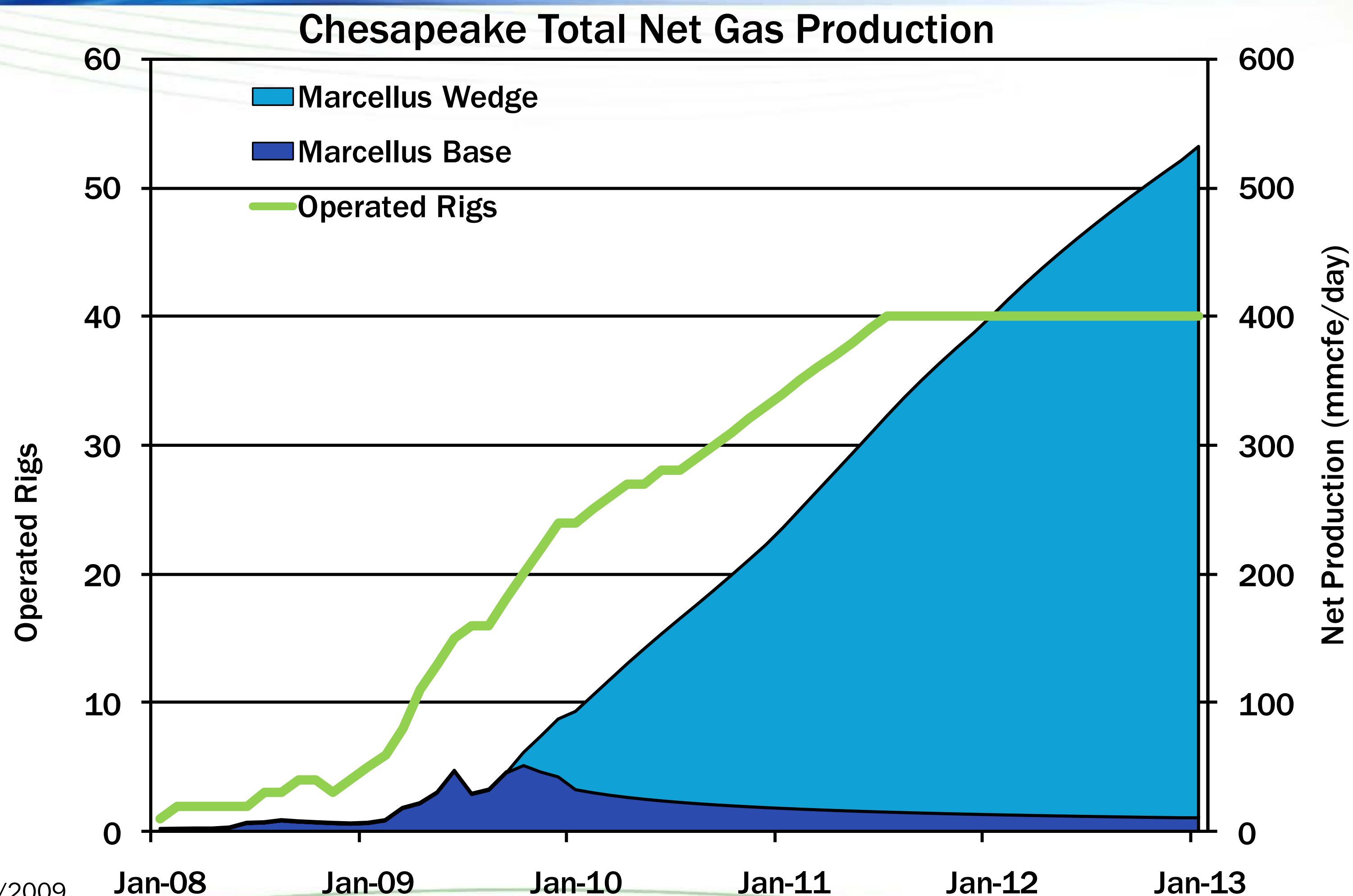
Marcellus Shale –
Rate of Return Profile



As of 10/15/2009

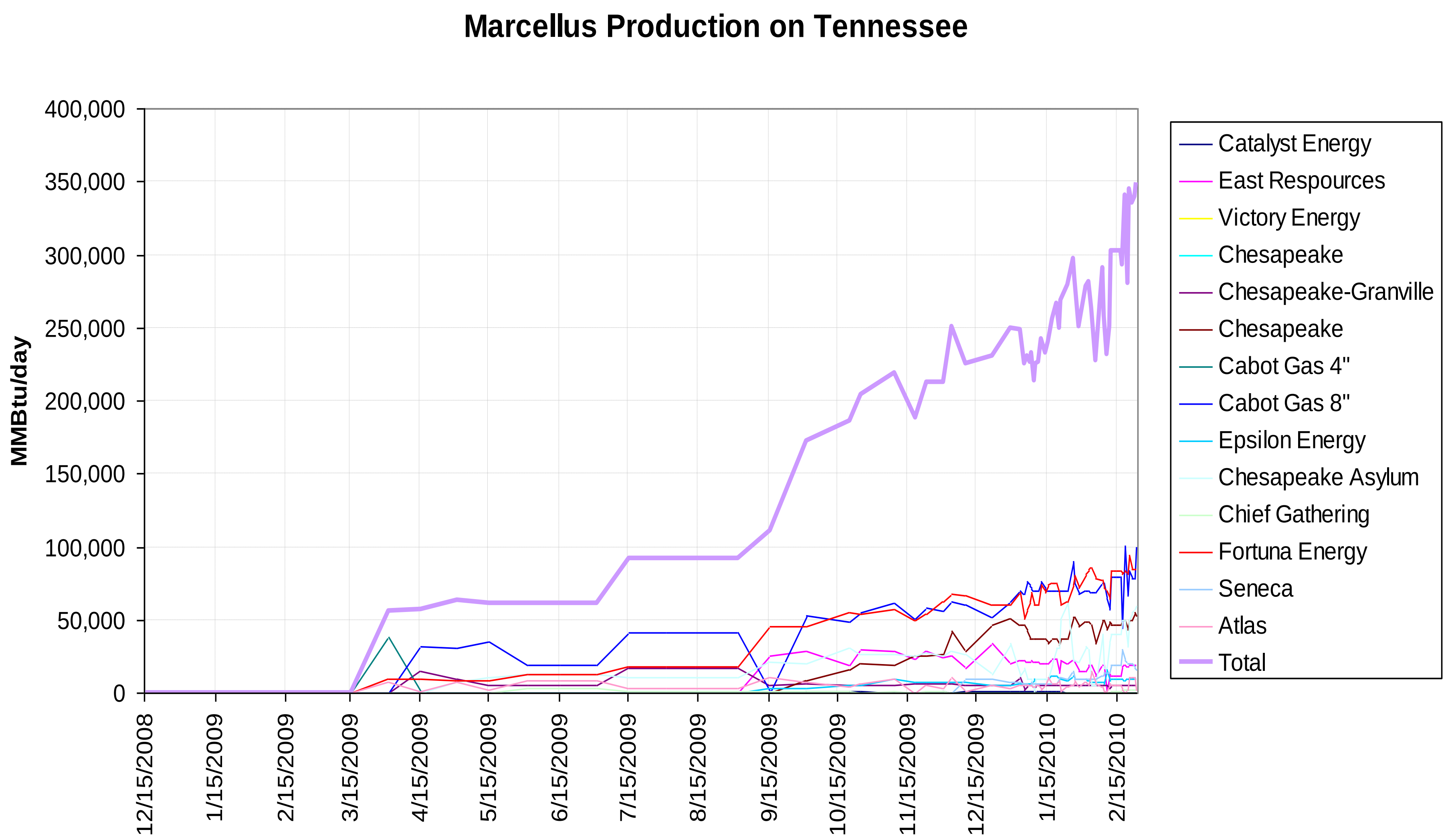
All RORs are pre-drilling carry from Statoil for 75% of CHK's share of drilling costs

Marcellus Shale – CHK Growth Profile



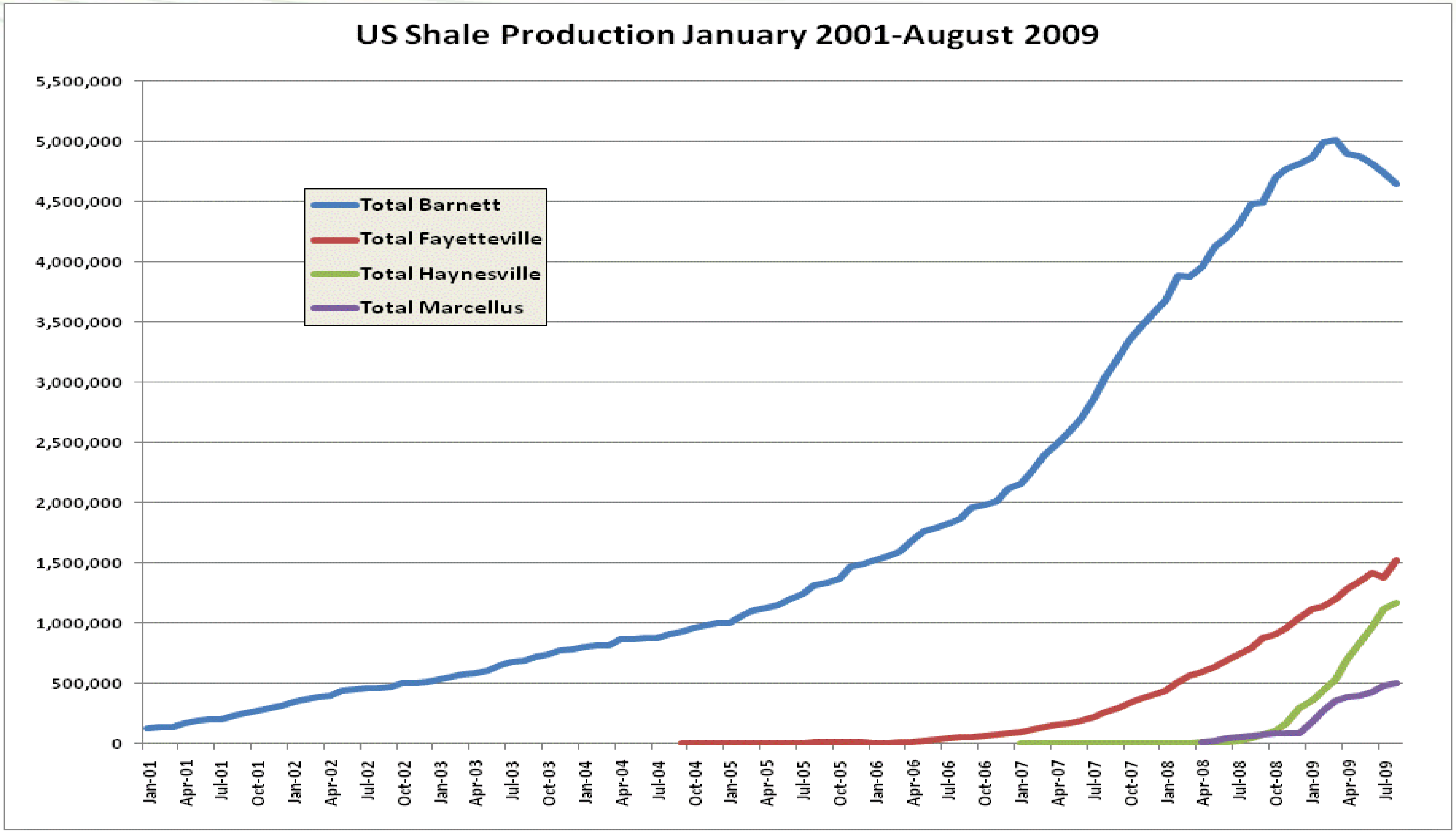
As of 10/15/2009

Current Northeastern PA Marcellus into Tennessee Gas Pipeline

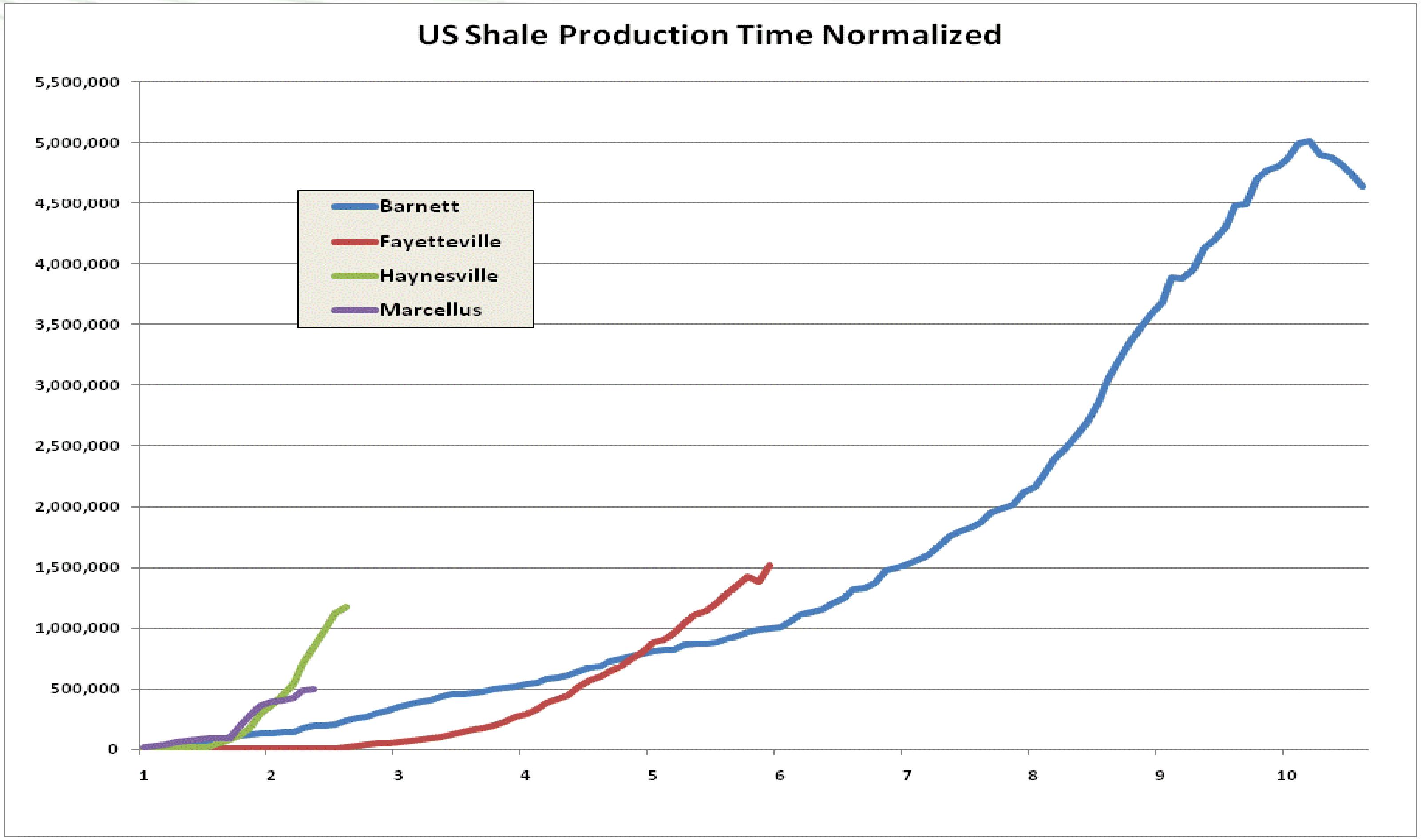


Source: Vantage Advisors, LP and Tennessee Gas Pipeline

US Shale Development



Shale Development Acceleration



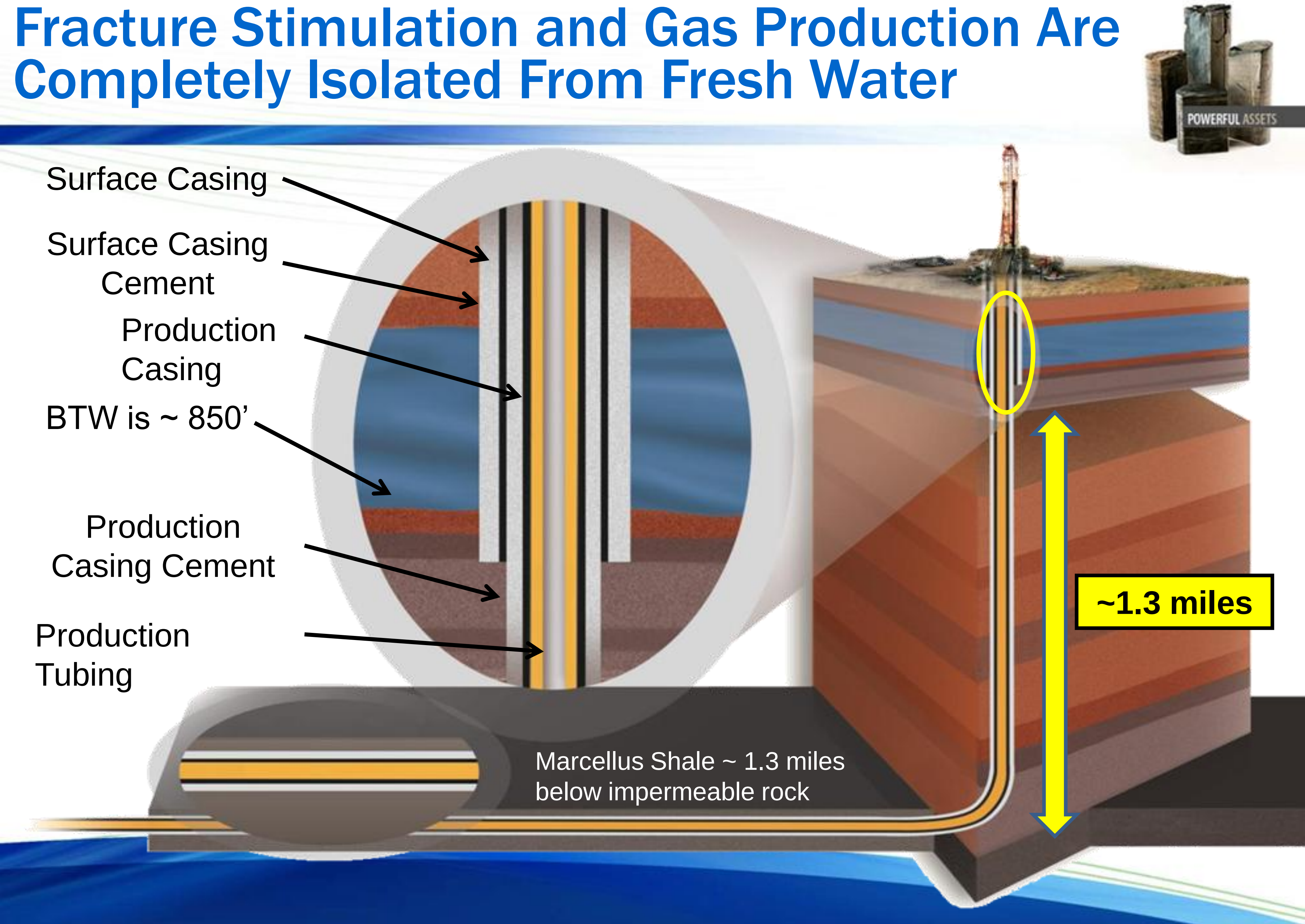
Marcellus Shale – Advantages

- **Advantages of the Marcellus Shale:**
  - World class basin size
  - Spans 15 million acres; 5x the Haynesville and 10x the Barnett
  - Close to U.S. population centers and best natural gas markets
  - Over-pressured reservoir
  - Significant portions of play are geologically stable - structurally uncomplicated
  - Largely located in rural areas

Chesapeake ENERGY

Is Hydraulic Fracture Stimulation Safe?

Fracture Stimulation and Gas Production Are Completely Isolated From Fresh Water



Components of Frac Fluid – The Facts

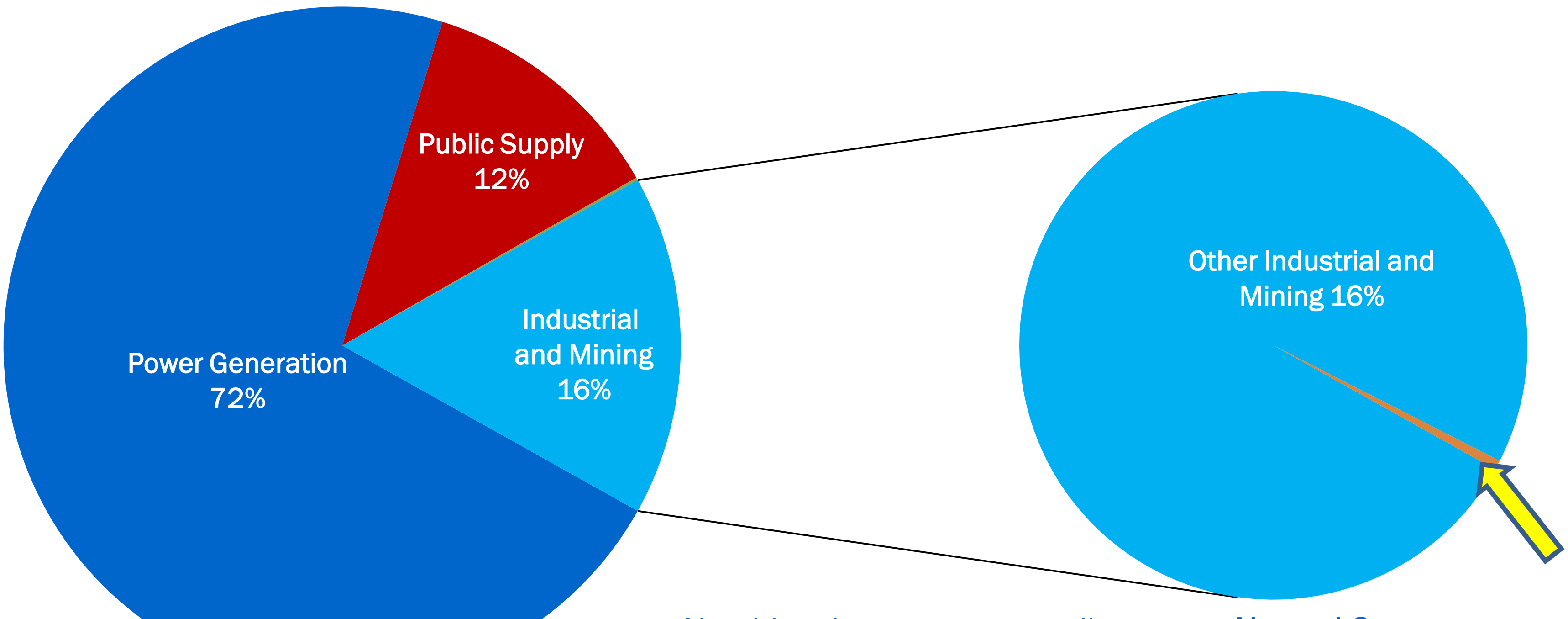
Product Category	Main Ingredient	Purpose	Other Common Uses
Water	99.5% Water & Sand	Expand fracture and deliver sand	Landscaping, manufacturing
Sand (Proppant)		Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete and brick mortar
Other	~ 0.5%		
Gel	Guar gum or Hydroexyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, baked goods, ice cream, toothpaste, sauces, and salad dressings
Friction Reducer	Petroleum distillate	"Slicks" the water to minimize friction	Used in cosmetics including hair, make-up, nail and skin products
Acid	Hydrochloric acid or muriatic acid	Helps dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Anti-Bacterial Agents	Glutaraldehyde	Eliminates bacteria in the water that produces corrosive by-products	Disinfectant; sterilizer for medical and dental equipment
Scale inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Used in household cleansers, de-icer, paints, and caulk
Breaker	Ammonium Persulfate	Allows a delayed break down the gel	Used in hair coloring, as a disinfectant, and in the manufacture of common household plastics
Corrosion inhibitor	Formamide	Prevents corrosion of the well casing	Used in pharmaceuticals, acrylic fibers and plastics
Crosslinker	Borate Salts	Maintains fluid viscosity as temperature increases	Used in laundry detergents, hand soaps and cosmetics
Iron Control	Citric Acid	Prevents precipitation of metal oxides	Food additive; food and beverages; lemon juice ~7% citric acid
Clay Stabilizer	Potassium Chloride	Creates a brine carrier fluid that prohibits fluid interaction with formation clays	Used in low-sodium table salt substitute, medicines, and IV fluids
pH adjusting agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Used in laundry detergents, soap, water softener and dish washer detergents
Surfactant	Isopropanol	Used to reduce surface tension of the fracturing fluids to improve liquid recovery from the well after the frac	Used in glass cleaner, multi-surface cleansers, antiperspirant, deodorants and hair-color

Putting Natural Gas Water Usage Into Perspective

Water Use in Marcellus Shale Area

POWERFUL ASSETS

Marcellus Shale water usage pales in comparison to other industries



Total water use in Marcellus area:
3.6 trillion gallons per year

Notable other uses too small to show on chart: Irrigation: 0.1%, Livestock use: 0.01%

Natural Gas Industry Projected Use 0.1%

Source: USGS Estimated Use of Water in US, County Level Data for 2000

Total water use (surface water and groundwater) in central PA (32 county area), southern NY (10 County Area), northern WV (29 county area), western VA and MD (5 county area) and eastern OH (3 county area) by sector

CHK is Successfully Managing Water

- Hydraulic fracturing will typically require ~4-5 million gallons of water for a 4,500’ lateral length well
- Water is piped to most sites and stored in a lined impoundment near one or more padsites
- Impoundments and piping minimize water truck traffic
- Flow back water from the frac is stored on site in tanks for reuse

Marcellus Fresh water impoundment

The Economic Case for Natural Gas

The Marcellus Shale Will Be PA's Future Economic Driver

- **2008 economic impact**
  - $2.3 billion in direct economic impact
  - 29,000 new jobs for Pennsylvania
  - $240 million in state and local tax revenue
    - More than 30% of all tax revenue stays at the local level
- **2010 projected economic impact**
  - $14.7 billion in direct economic impact
  - 100,000 new jobs for Pennsylvania
  - $800 million in state and local tax revenue
- **2009 - 2020 total projected economic impact**
  - $265 billion in economic impact
  - $15 billion in state and local tax revenue
  - Potential for ~200,000 new jobs for Pennsylvania by 2020
- **Bigger economic impact on Pennsylvania than oil in late 1800's or steel in early 1900's?**

Chesapeake ENERGY

SOURCE: *Penn State University – 8/5/09 Prospects and Economic Impacts of Developing the Marcellus Shale*

Marcellus Landowner Impact Illustration

POWERFUL ASSETS

4.2 Bcf/well@ $5 = $12.3 MM NPV@6%

One Well = 80 Acres
Average Royalty -16.34%
NPV Royalty per well - $2.01 MM
NPV Royalty per acre - $25 K
NPV Royalty per Dth - $0.48

Royalty NPV 1 Bcf/d	Royalty NPV 3 Bcf/d	Royalty NPV 5 Bcf/d	Royalty NPV 10 Bcf/d
$175 MM	$525 MM	$875 MM	$1,750 MM

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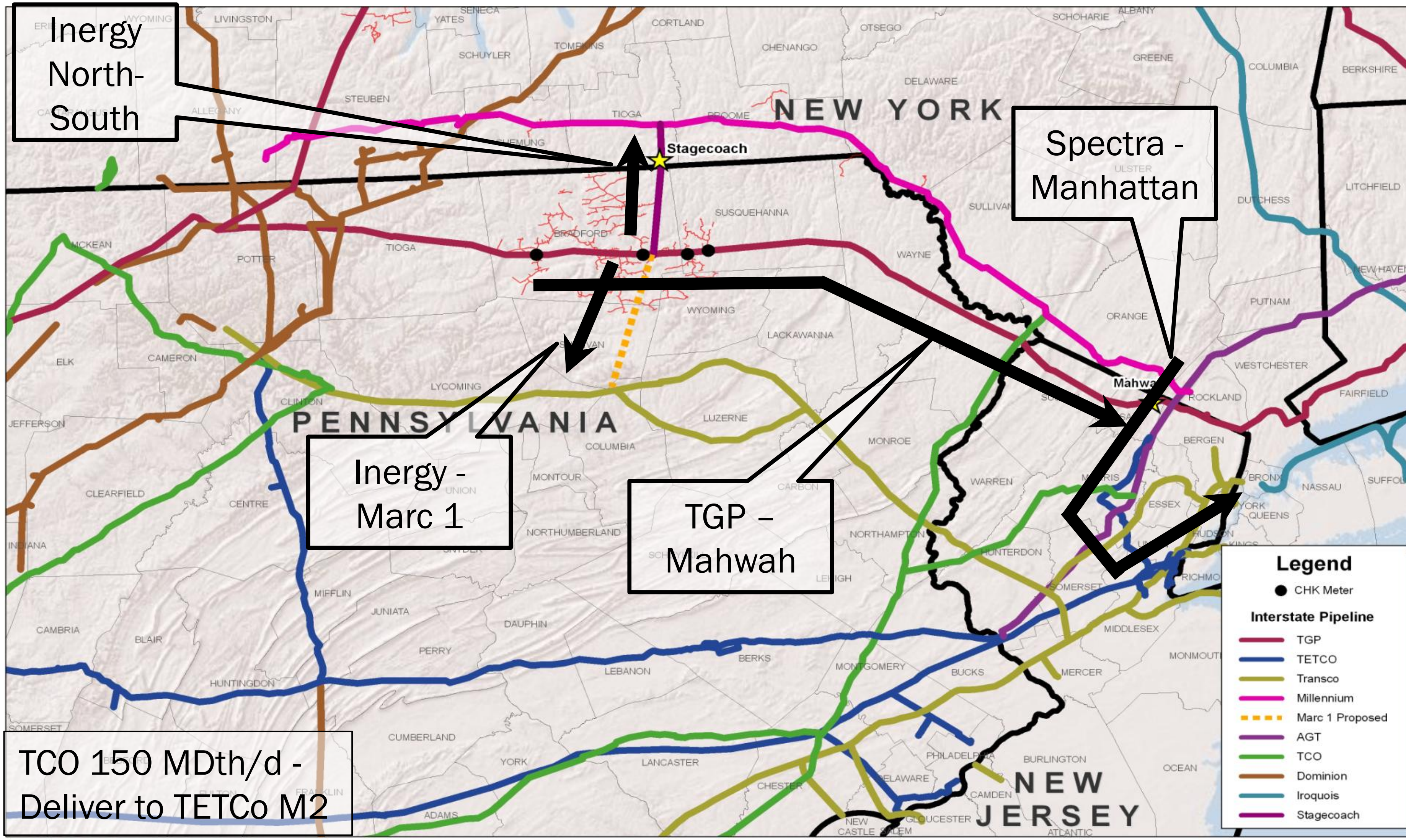
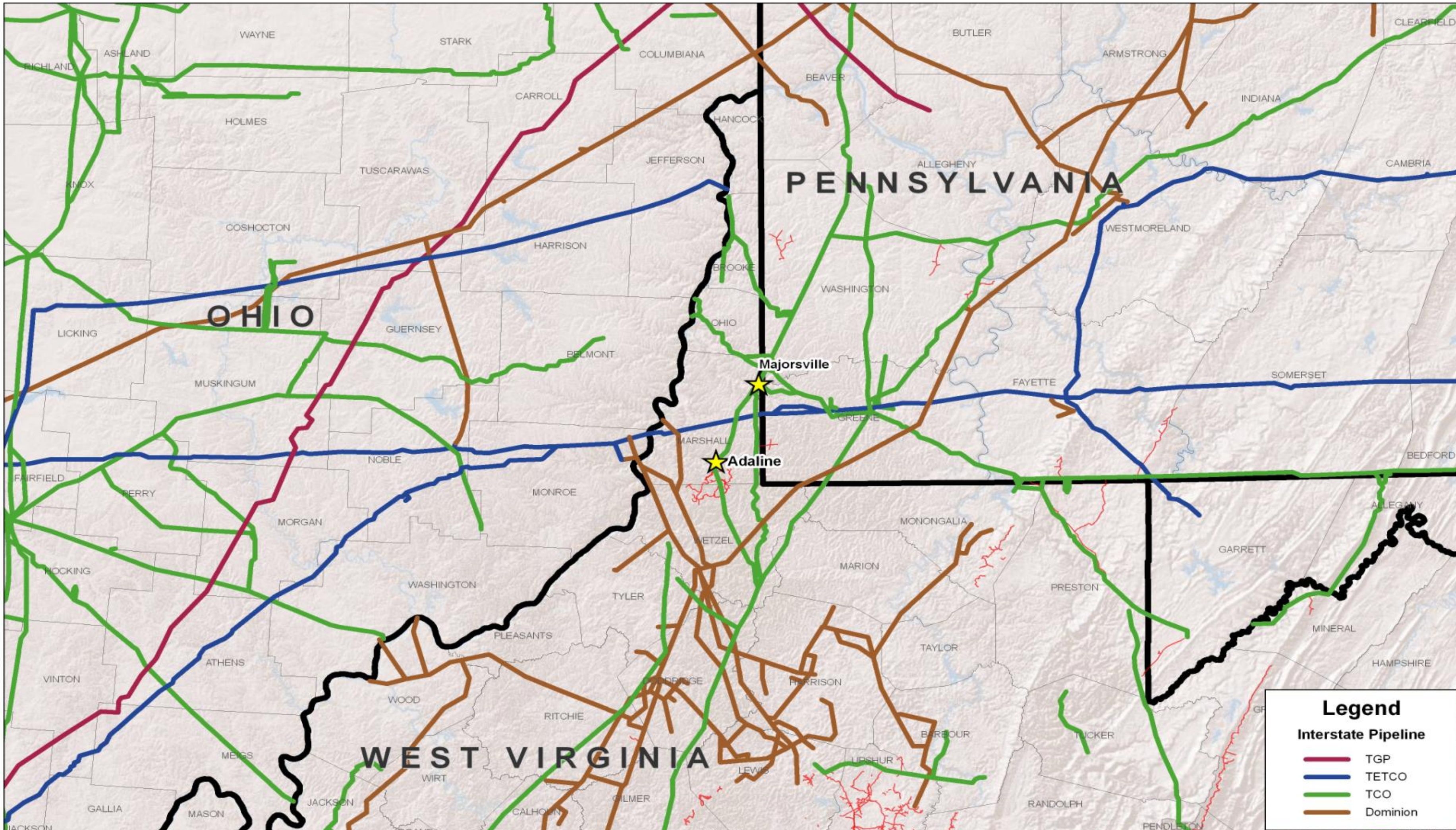
The NGV Opportunity

- The transportation sector accounts for 30% of U.S. CO_2 emissions
- Converting one heavy-duty truck from diesel to natural gas is the pollution-reduction equivalent of removing 325 cars from the road.
- There are more than 10 million NGVs worldwide, with only about 120,000 in the U.S. – ranking the U.S. 12th in the world

CHK Marcellus Capacity Subscriptions

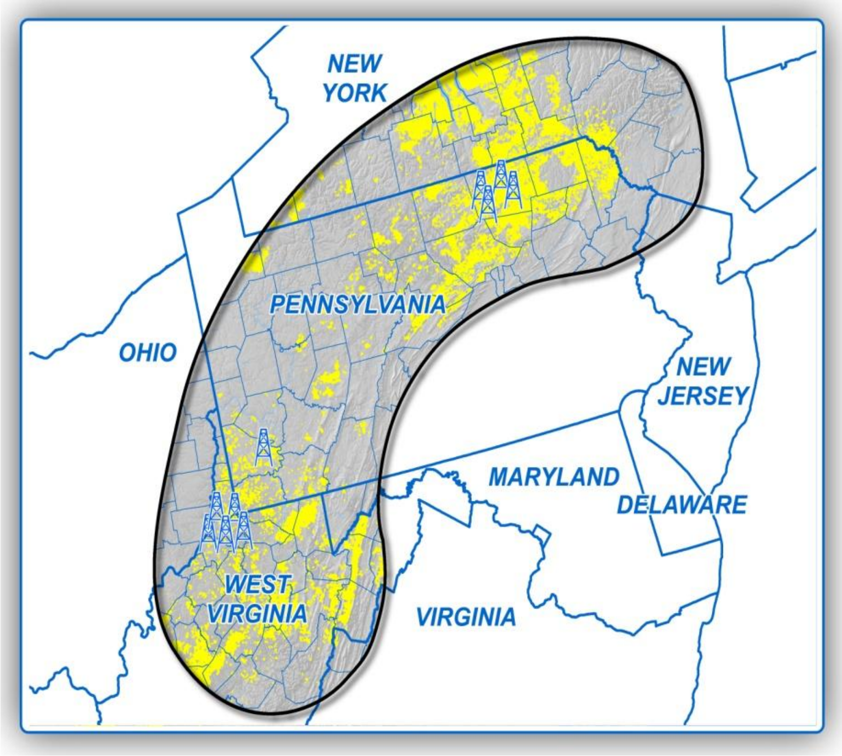


Southern Marcellus Development



Final Thoughts on Marcellus

- **Reduced pipeline variable cost to NE and Canadian markets**
  – Marcellus should be the first choice for supply
- **First round of pipeline expansions - NYC**
  – Next destination(s)?
- **Potential new trading hubs – best location(s)**
  – An expanded Leidy market?
  – A new M2 market?
  – An expanded Niagara market?
- **Should increase natural gas market share**
- **Will increase NGL availability**
- **Storage implications – need more in the region**
- **Pricing implications – should reduced volatility**



Certain Reserve & Production Information

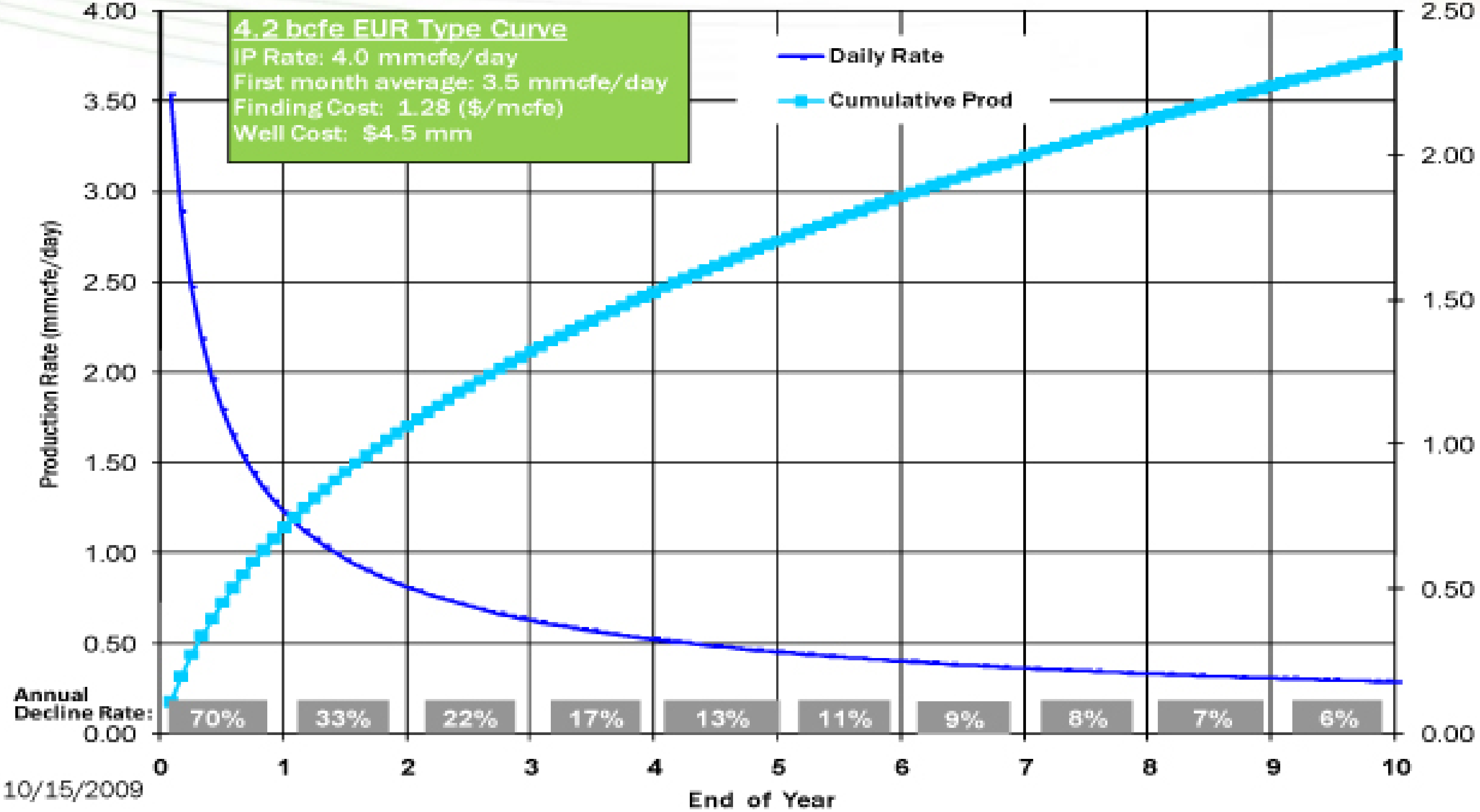
- The Securities and Exchange Commission requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of natural gas and oil that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. In this presentation, we use the terms "risked and unrisked unproved resources" and "estimated average resources per well" to describe Chesapeake's internal estimates of volumes of natural gas and oil that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. These may be broader descriptions of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. Estimates of unproved resources are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. We believe our estimates of unproved resources, both risked and unrisked, are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.
- Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Although we believe the forecasts are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions and data or by known or unknown risks and uncertainties.

Forward-Looking Statements

- This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of our natural gas and oil reserves and resources, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned asset sales, budgeted capital expenditures for drilling and acquisitions of leasehold and producing property, and other anticipated cash outflows, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Although we believe the expectations and forecasts reflected in forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.
- Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our 2008 Form 10-K and our 2009 second quarter Form 10-Q filed with the U.S. Securities and Exchange Commission on March 2, 2009 and August 10, 2009, respectively. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; impacts the current economic downturn may have on our business and financial condition; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including through planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; exploration and development drilling that does not result in commercially productive reserves; expiration of natural gas and oil leases that are not held by production; hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities; uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; transportation capacity constraints and interruptions that could adversely affect our cash flow; potential increased operating costs resulting from legislative and regulatory changes affecting our operations; and losses possible from pending or future litigation.
- We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation, and we undertake no obligation to update this information.

Chesapeake ENERGY

Marcellus Shale – Targeted Horizontal Well Profile



As of 10/15/2009

	CHK	Range	Ultra	Cabot	Talisman
IP	4.0 MMcf/d	4.9 MMcf/d[2]	7.5 MMcf/d[1]	6.9 MMcf/d[1]	4.5 MMcf/d
EUR	4.2 Bcf	3-4 Bcf	3.75 Bcf	5.5 Bcf	5 Bcf

[1] 30 day IP [2]Average Horizontal IP

Chesapeake ENERGY

SHALE GAS – A BUSINESS PLAN VERY MUCH IN THE RED

by Marc Durand, doct-ing géologue
Professeur retraité
dépt. Sciences de la terre,UQAM

Following the publication on the Web of my article on shale gas -*Gaz de schiste- quelques réflexions d'un géologue,* I received numerous comments, one of which was the following question from Claude Paré:

I would like M. Durand to clarify two points. I know he is knowledgeable about cement - what, in his opinion, is the life of these wells; could they become conduits for the liquids and the gases . Can the saline solutions and the fracturing fluids buried underground weaken the cement?

I haven't read all the briefs to BAPE, but among those I have read there is not one which asks or addressses your question, which I would reformulate thus: "What is the life-span of a well - including its ability to contain the drilling permanently, and what will happen when the underground part of the well loses its integrity through corrosion and other degradations?"

There is necessarily an expiry date; this is longer for structures that are inspected and maintained, and shorter for temporary works; all engineers know this fundamental fact; for example the tunnel lining required to stabilize and enclose the vault of a metro tunnel is not the same as a temporary gallery for a mine. In the case of the metro, it must be very solidly and durably constructed; and a program of inspection and upkeep added for the whole duration of its use.

We have seen this recently with viaducts and bridges; at the end of their life ,and preferably before, they must be demolished and rebuilt. One cannot take a chance of allowing a structure to exceed its lifespan. Certain bridges, well maintained, last for centuries; others ,badly suited to their use and exposure, have a life span of only 50 years. For a temporary building, or one which humans do not use, the criteria for security and life span are lower.

All that we know about shale gas wells is that these are works designed for a very short life span: the years of the well exploitation. After it has been capped (cemented), the top of the structure is buried and vegetation planted on the site .(brief to BAPE). There is practically nothing published which would respond to Mr Paré's question about the life-span of the subterranean structure. The question is, however, essential.
In 20 or 30 years how much will 20,000 depleted wells, which will simply have been concealed before being bequeathed to the geographic locale, cost us per year? There is total silence on this question, because the mining and oil sector has never been concerned for what happens to the drill holes afterwards. The industry has never allocated funds for that. The newest legislation requires only the rehabilitation of the site at the end of its exploitation. Companies must restore the surface of the site but there is almost nothing for what is underneath.

There are thousands of well sites at the end of their life span , hidden in the surface vegetation which have become all the more dangerous because their location has been forgotten. In the United States, there are more and more reports of victims of explosions from gas which resurfaces from old wells. In the majority of cases, it is old exploration wells dating from the beginning of the last century (Appalachia, Colorado). The problem will take on a whole new dimension shortly with the end of life of the gas wells situated in layers which have undergone intense modification by hydraulic fracturing. The technique, newly applied on a large scale, will leave thousands of abandoned wells under inhabited zones, without anything being known of the impacts which will arise at the end of the work.

Lets be clear about what we understand by the end of the life-span of a shale gas well. A working well has a life of 3-5 years. It is an optimal plan for extracting the gas as quickly as possible at the lowest cost. The output the fractured shale delivers is very high at first , then it diminishes logarithmically or exponentially. The wells are abandoned when the rate of gas is deemed unprofitable; at which point about 20% of the gas in place has been captured.

In classic gas reservoirs, up to 95% of the natural gas can be captured " *For shales*, *recoveries are expected to be around 20% because of low permeabilities despite high- density horizontal drilling and* ex*tensive hydraulic fracturing* ." National Energy Board, *A Primer for Understanding Canadian Shale Gas (* http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.pdf)

At the end of this period the extraction well is summarily transformed for another job or task whose sole purpose is to stop the flow of gas in the well. By means of blocking downhole plugs, cement plugs in the tubing, etc., the temporary extraction site must be turned into something permanent, the function of which is very different. In reality, practically nothing changes in the structure and composition of the well but the addition of a permanent plug. Whatever the design of the plug, the new work cannot have a drastically modified life-span. Nevertheless, these plugged wells must resist in perpetuity the pressure of the methane which will continue to seep from the fractured shale. And let's not forget that 80% of the gas remains in the shale at the end of extraction.

Underneath the inhabited plain, the Utica will have become an extremely permeable reservoir, still containing the left over methane after the skimming of the 20%. This enormous volume , 100 metres thick times 10,000 Km squared will be directly connected to the surface by 20,000 slowly corroding wells .The steel pipes and the sealing grout in an extremely saline environment will erode. This will possibly vary in speed from one well to another according to the quality of the sealing work done. The life duration of each of these wells, is the time before the deterioration is so advanced that major leaks force the authorities to intervene. From then on there will necessarily be a cost . This cost may appear very early in the process for certain wells, as has happened in Québec with some wells whose exploitation phase hasn't even begun; but for now, the industry is still the owner of the wells and so pays the cost. This demonstrates though, that leaks occur even with brand new wells.

Figure 1 shows various routes the gas can take to reach the surface and drinking water wells.(P) The light blue letters(A,B,C) show the gas flow in the case where the drilling intersects a flaw or a long fracture. It is difficult to estimate in what proportion of wells this could occur because a detailed geological map is not readily available for the rock under the soft deposits of the St Lawrence Valley.

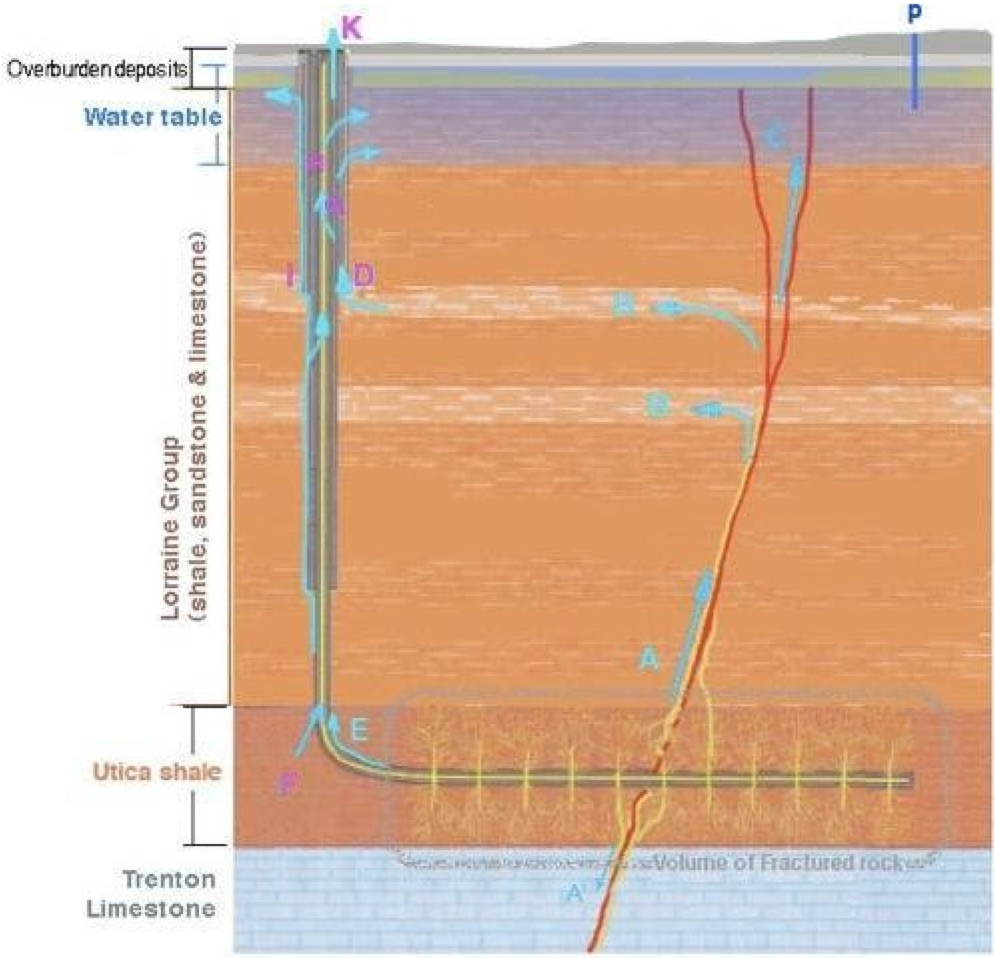


Figure 1 : possible leaks for an extraction well – capped well.

Where there is the presence of such a fracture, the injected liquid opens this route and pushes very far (A) into the Lorraine strata. The flow path is opened permanently to continue into the sandstone and other more permeable layers.

Gas leaks show up in the artesian wells and the dwellings in proximity to the fault. Note that the fracturing fluid also penetrates a great deal further than the fault in the limestone (A) The Trenton is more permeable than shale and it contains very salty water. Thus a route is opened for saline contamination. Some analyses of fracking water indicate that this type of problem has already been encountered in the first wells.

Between the pipes and the drilled rock, and between the producing pipes and the protective sheath, the quality of the placement of the grout can leave spaces : annular fractures may also form during the intensive use of the wells. So that it is a possible origin of gas leaks coming from the wells themselves (E and K)

As well as these possibilities of leaks, at the end of the well's life, probably between 2 and 5 decades after the end of operations, more generalized leaks will begin progressively, in growing proportion to the abandoned wells. The first reasons will be : 1) the disintegration of the steels and cements of the seal. 2) the pressure of the gas which builds slowly and surely on the capping. 3) the readjustment of the pressure (more precisely, the state of the constraints) in the fractured rock will slowly readjust, shearing off or deforming locally sections of the pipes.

The Utica strata tend to inflate when exposed; the same property in the depths will tend to flow and close up the opened fractures a bit over time. The fractured shale will thus tend to lose some of its permeability; but this will not be sufficient to return it to its initial impermeability. On the contrary, these micro ruptures will contribute to the liberation of yet more methane over time.

We are dealing here with structures which will disintegrate in extremely salty environments underground far from all possibility of inspection and maintenance, in rock transformed by the operations of hydraulic fracturing. The flow of fluids, saline water and methane will become modified. All the structures linking the surface of the transformed Utica will sooner or later attain an advanced degree of decomposition. The wells will reach a state where their function as sealing devices will no longer be operational. That means what exactly? : mega-problems at each of the wells, means of mitigation to be put in place , complex studies to be undertaken to try to find a solution, BAPE commissions for each site? (see my analysis of the Mercier case in my preceding text) There will be many of the 20,000 , maybe between 250 and 500 new cases per decade in one generation. Billions to plan for in the budget of Québec.

If the heads of the wells are kept accessible for perpetuity, rather than restore the surface,one would have a less complex task, because one could sound the ground and know when catastrophe threatens. Yet no one anywhere is proposing that. It is said that the site must be restored at the conclusion of the extraction. All that means is burying and forgetting the problem until it hits us in the face. Finding a solution at that point will be an impossible task, as it is impossible to obliterate a well . The hole remains there, even if one tries to plug it with something else, that other material will never have the same properties as the shale that has been drilled and fractured. This Utica Shale has contained the gas for 400,000,000 years.
All our technology, present and future will never manage to do that well.

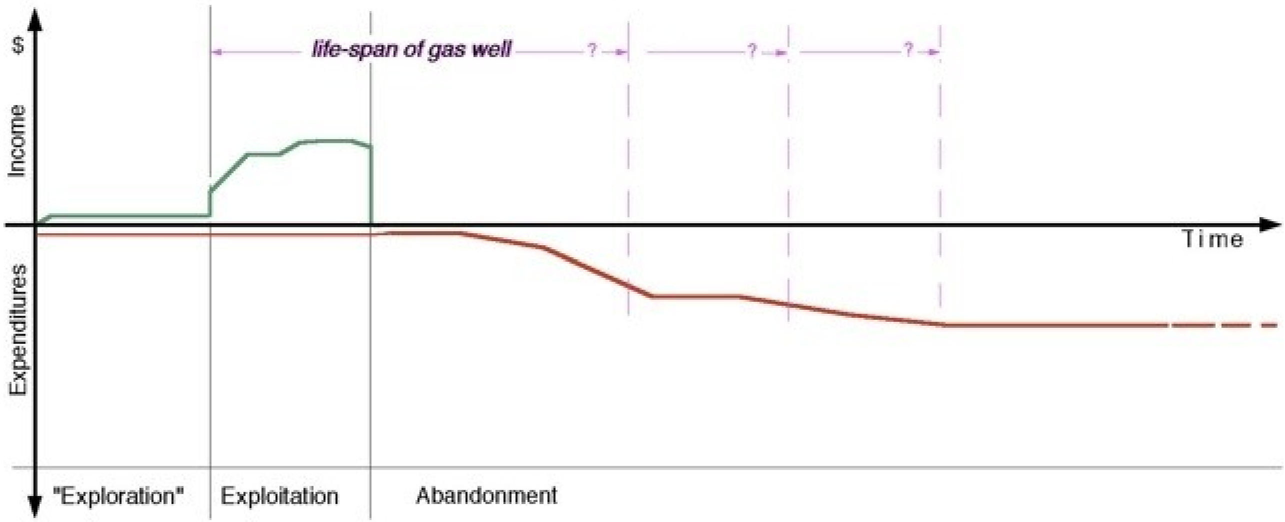


Figure 2: Business plan with schema of the life-span of the wells.

Figure 2 above shows shows revenues and costs for Québec as a whole, that is, the community. The business plan of the gas industry ceases with steps 1 and 2 ; it ends with the halting of the exploitation and the time required to restore the surface. During the first stage (EXPLORATION), the collectivity receives modest annual revenues in the form of exploration permits . For example: 10 cents/hectare +$100/drilled well. Québec, on the other hand, has the costs of analysis, surveillance, inspections, etc. It is certainly a negative balance sheet for the collectivity at this stage. During the exploitation, the surveillance and other costs continue but they are largely compensated for by the fees paid on the extracted gas. At the end of the exploitation, the gas companies cease to pay these taxes. They may also cease to pay the mining rights fees , which would be in their interest. In that case, the full ownership of the gas deposit reverts to the government. The diagram indicates that the life span of these capped structures remains unknown; but we know that it does come to an end. In the current business plan, if one can believe the lessons of the past, it is the collectivity who will assume the costs which will, sooner or later, inevitably appear.

The capped wells will not all have the same length of life. For a small number, the deterioration will be apparent soon enough, in the greater mass later, and a last group may miraculously not show any sign of problems for generations. On the whole, the costs may appear early, with an unending increasing curve, mostly near the time which corresponds to the average life-span of the works (figure 2)

Whatever the parameters are, the business plan of Gaz-Québec Inc, that is to say, our communal interest in this file, will be strongly one of deficit. Only one winner: the gas companies who have passed us "un beau sapin" (a wooden nickel ; literally :a nice fir tree)
It is the official name of the well heads (Christmas tree) and that is not a coincidence; it is an omen which tells us to light the lamps while there is yet time.....

CONVENTIONAL GAS vs HYDROFRACTURING GAS SHALE

by Shale Gas Info on Saturday, March 12, 2011 at 5:03pm

The Exploitation of Conventional Gas Wells vs Exploitation by Extended Horizontal Drilling and Hydraulic Fracturing. **(**Translated by Ingrid Style)

Why isn't it possible to extract more than 20% of the gas in a shale gas deposit and what are the consequences of that fact? Notwithstanding the still limited knowledge we have of the long term impacts of the technique of hydraulic fracturing in extended horizontal bores, we shall analyze the more obvious differences between this new technique and classical gas exploitation.

In conventional exploitation, the gas deposits are found in specific geologic structures: a formation or geologic structure of great porosity resulting from inter-granular spaces and/or natural inter-connecting fractures, the whole capped by a watertight formation which seals the top of the reservoir, as in the schema below.

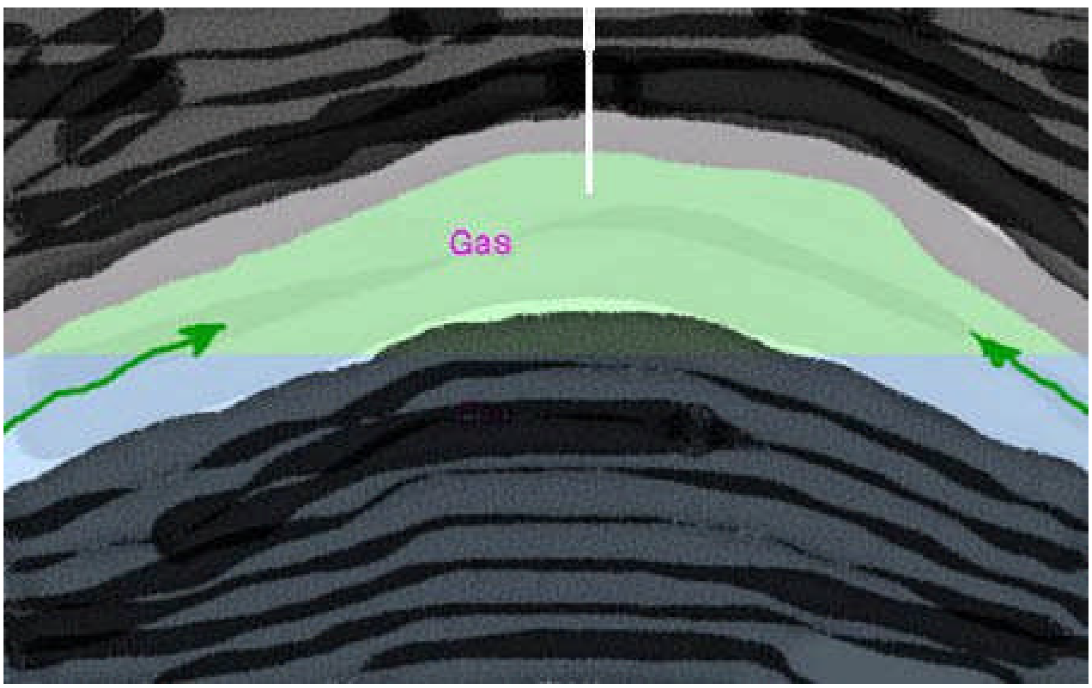


Figure1. Conventional natural gas reservoir, in which the gas migrated over geologic period of time to reach a porous and/or natural fracture zone.

Once the gas vein is found, following a real geologic exploration, the extraction well drilled into the reservoir is able to extract almost all (>95%) of the gas in the deposit. The gas is propelled to the surface by the water. (there is a possibility of liquid hydrocarbons between the water and the gas). It is important to note that this gas has VERY slowly migrated from a matrix (a sedimentary rock which may be shale for example) and has accumulated in this natural reservoir in a process which has taken hundreds of thousands of years, and more probably millions of years. Why? Because the shale matrix has a very low permeability coefficient (< 10exp-12m/s). Once inside the permeable rock of the geologic pocket the permeability is of a much higher order (>10exp-6m/s). In exploiting a natural deposit then, the gas migrates easily towards the extraction well. Thus eventually the production of the well falls to zero. The reservoir is not 100% empty, but almost.

It is extremely dangerous to extrapolate from the above scenario to that of shale gas: in the case of shale gas the fracturing is immediate and we do not reach equilibrium at the end of the exploitation. Moreover, the effects are not limited to a local deposit but extend to radically transform an entire layer.

In the case of artificially fracturing the shale gas deposit itself, the gas migrates over a shorter distance than the long migration of the classical natural gas, but it is not an instantaneous process. Within a few mm of the edge of a fracture, the gas escapes fairly quickly (see below), but the greater the distance, the more one must count on geologic time for the process of migration to happen in the new shale as it once occurred with the natural reservoir. With a permeability of 10-12 cm/s, for example, even under a gradient (i) elevated by 100, the time required to traverse only a few centimetres is on the order of centuries or even millennia (v = Kxi). **That is how things work in the parts of the shale which remain intact between the fractures . But because of the steep gradient, migration will occur.**

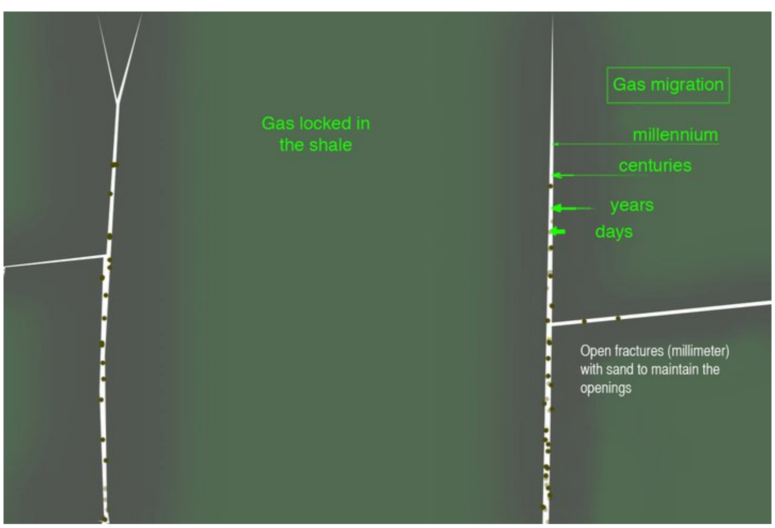
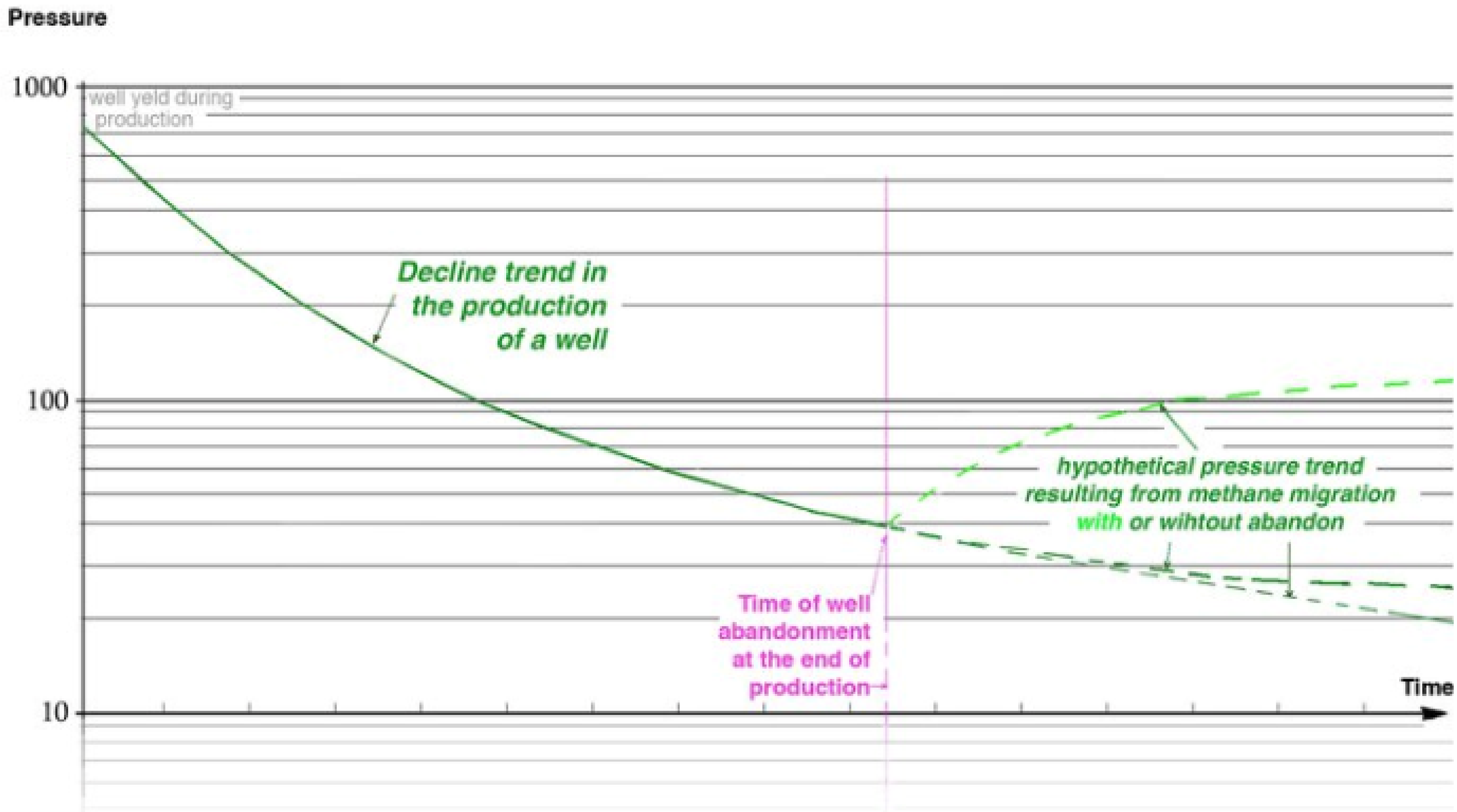


Figure2. Gas migration in the shale in proximity to the new fractures; metric view of

shale at the end of exploitation (5 to 8 years?).

The exploitation by hydraulic fracturing produces elsewhere descending logarithms, or exponentials as in the figure below for the Marcellus.



Pressure
1000
100
10
well yeld during production
Decline trend in the production of a well
hypothetical pressure trend resulting from methane migration with or wihtout abandon
Time of well abandonment at the end of production
Time

Figure3. Theoretical production rate decline for the Utica shale, based on what is observed in the Marcellus.

The output is only commercially viable for a few years; it is absolutely absurd to say (as did the Talisman geologist *) that afterwards there is no more gas and one seals the wells. There is no zero output until time reaches infinity, in this type of curve.

On top of this, the National Energy Board estimates that the extraction leaves 80% of the gas in the shale. Nothing will stop the process once begun. It will continue for centuries and millennia. The well caps do not have a comparable lifespan. It would be truly astonishing if the the gas industry has in the last eight years invented structures capable of lasting for millennia. The ongoing gas migration will slowly restore pressure in the wells. After a geological time span, this new level of fractures may become a comparable deposit to the conventional gas deposit.
Civil engineers always would have loved to have techniques to make viaducts and bridges last more than fifty years. Here, the gas industry, with the same materials, steel and concrete**, is asking us to believe that they have the recipe for thousands of capped wells to eternally resist the growing pressure in a great fractured Utica reservoir, under our feet in the St Lawrence Valley.

The case of the 31 wells already drilled
I suggest that we quickly find a method of managing the wells already in place; about half have reached the hydraulic fracturing stage, which reduces the number requiring treatment to less than twenty. But this nevertheless means a several sites to manage. The public absolutely must not, one day, inherit this task.
The gas industry which effected the drilling must insure its future management in the very long period following its exploitation. Legislation must be reviewed to insure that the responsibility for the wells remains with those who dug them.

The present government has a penchant for projects in which the the private sector constructs, exploits, maintains, etc . This style of management should be the one applied to the 31 wells . By means of a 99 year lease with compulsory renewal at the end of this time, each of the well owners would have complete responsibility and should hold insurance and a guaranty of solvency. Being responsible for any problem that may manifest will change the game. The industry should not balk at this obligation, because according to what it asserts (and contrary to what I believe), there will be no problems. Personally, I am convinced that rigorously imposing this sole requirement, will be sufficient to completely halt further activity here in the Utica.

The idea of obligating the constructors of the wells for 9 times 99 may appear preposterous on first blush, but I cite a source that the industry should not contest : Halliburton. On the pages that deal with gas shales, there is not one line on the long-term risks. But on other pages dealing with CCS (Carbon Capture & Storage) the Halliburton techniques of sounding and repairing the ageing wells are lauded: in cycles of soundings- repairing- returning to a phase of soundings, all this over centuries, even millennia . <<The Post-Closure phase addressses post decommissioning – which has an extremely long time horizon of hundreds, if not thousands of years >> http://www.halliburton.com/.

These wells that Halliburton indicates should be followed for millennia are à priori less risky than the wells with horizontal extension and hydraulic fracturing: these are vertical wells connecting on the surface with CO2 storage tanks, less problematic than methane. The gas industries are not ignorant of the long term risks; they are only pretending that these don't exist and that the wells can innocuously revert to the public domain. There is no regulation anywhere which obliges them to include these long term risks in their business plans. On the other hand, they know they must act quickly because the situation can change.

In conclusion

There are two important differences between shale gas and conventional gas deposits and **these two differences provide in themselves the fundamental reasons for rejecting totally** the ill-considered idea of shale gas exploitation by means of the currently proposed technique:

1) Hydraulic fracturing artificially creates a network of interconnected fractures towards which the gas begins to migrate. The technique initiates the flow of gas in the deposit as happened in the classic natural gas deposits over hundreds of thousands of years, but **the technique can not speed up the geologic process**. The construction of a well and its fracturing are completed in a few week; the flow begins and continues on a geologic time scale (greater than 100,000 years). The amount of time before the well is closed (once the rate of flow is no longer commercially viable) represents no more than an infinitesimal portion of the geologic time.

2) The drilling of wells and the fracturing of the homogeneous rock is a totally irreversible operation with no technical solution to restore the the shale to its original impermeable state. These gas wells closed off at the end of commercial exploitation become potential conduits for the gas leaks. For these structures, as all structures

made of steel and concrete, there is the fundamental question of their life span – from which follows the question of what will happen when their state of degradation can no longer withstand the pressure of the gas. This pressure in the reservoir will grow slowly but continually while the well structures will continue to degrade. These two phenomenon will in time become manifest on the surface in the growing number and increasing flow of methane leaks. The management of these buried works will cost colossal sums.

Marc Durand, doct-ing en géologie appliquée Professeur retraité, dépt. Sciences de la terre, UQAM

*http://www.facebook.com/note.php?note_id=189917767706479
**more precisely cement grout in the case of the wells and not real concrete; the grout is a great deal less resistant and durable than real concrete.

Couple files complaint with DEP over source of foul water

September 9, 2010 - By CHERYL R. CLARKE
cclarke@sungazette.com

GRANVILLE SUMMIT - When Chad and Shana Spencer of this rural township in Bradford County agreed to allow Talisman Energy (formerly Fortuna) to harvest natural gas from beneath their property, they never dreamed the end result would be the loss of their water well.

The Spencers live on 1.34 acres and had signed a "non-surface rights" lease with Talisman on the verbal condition that their well water would not be tainted, but when the water coming from their faucets began to show turbidity and was full of sediment, Shana Spencer said she thought her worst fears were coming true.

Spencer, a stay-at-home mother of four children, said the water began showing signs that something was wrong back in late 2008, shortly after drilling began on the Foust well about a half-mile from their Granville Township home.

"On Nov. 16, water had come out looking disgusting, full of sediment. We had lived here about four years and never had issues with the well water - ever. So, I thought it had to be coming from the gas company," Spencer said.

The Spencers had not had their water tested before drilling began, because they thought the gas well was far enough away that it was unlikely anything would happen. Plus, Shana said, "we didn't have $800 lying around to have our water tested."

After not getting satisfactory results from Talisman, Spencer said they decided to file a formal complaint through their attorney, Bruce Vickery, of Wellsboro, with the Department of Environmental Protection against the natural gas drilling company for contaminating their well water with methane gas and aluminum, rendering it unusable, they said.

Spencer said Talisman eventually sent someone out to gather water samples for testing as did the DEP.

DEP community relations coordinator Dan Spadoni said the agency has been contacted by the attorney representing the Spencers with an e-mail filing a formal complaint.

"However, we have not yet responded to that e-mail and we cannot speculate at this time what our response will be," he said.

Spadoni added that the department has investigated past complaints from the Spencers regarding methane gas in their drinking water well, and sampling done in January confirmed elevated levels of methane in the water.

"However, DEP has not made a final determination on the source or sources of that methane," he said.

Additional sampling at the Spencer well was performed by the agency in May and August and they are awaiting those results, Spadoni said.

"We will provide (the results) to the Spencers after our review of them. It's our understanding that Talisman Energy is voluntarily in the process of drilling a new drinking water well for the Spencers. We do not anticipate any further comment at this time," he said.

But according to Spencer, Spadoni told them that there would be a significant danger of fire, ignition or explosion if methane levels above 28 milligrams per liter were detected.

The Spencers' water showed 67 milligrams per liter, according to the water analysis provided by Talisman, and finally released to the family 13 months after it was done.

Now, some 18 months after they first were approached by the drilling company, they and their family can no longer drink, bathe in, cook with or use their original well water for anything because it is contaminated with methane, reportedly from a "deep source."

But the worst part of it is, Spencer said, Talisman allegedly knew the water was contaminated for more than a year, and "sat on it," never telling the family.

When they were informed by letter dated Jan. 10, 2010, there was only the technical information listed, she said, with no explanation of the results.

Spencer said although Talisman has since drilled two more water wells on their property to look for a source of potable water, it has had limited success, with the most recent well yielding only 2 1/2 gallons of water per minute.

The Spencers' original well produced nine gallons per minute, the owner said, and the new well has proven to not be much better.

A separate study by Duke University showed the water in their new well to be "35 percent methane."

"We were able to light this well water on fire two weeks ago. Our levels go up and down," she said.

Mark Scheuerman, director of government and media relations for Talisman, declined to comment on the matter.

----- Original Message -----
From: Richard Averett <mailto:averettr@frontiernet.net>
To: Richard Averett <mailto:averettr@frontiernet.net>
Sent: Wednesday, September 08, 2010 3:17 PM
Subject: [sustainableotsego] Methane found in Bradford County wells
pressconnects.com <http://pressconnects.com> Press & Sun-Bulletin

Methane found in Bradford County wells

Staff and wire reports • September 8, 2010, 10:00 am

Pennsylvania environmental regulators are investigating the source of stray methane gas found in the North Branch Susquehanna River and six private water wells in Bradford County last week.

Environmental Secretary John Hanger says the gas "probably ... migrated through the ground as a result of drilling in the area." He says the gas is most likely not from the Marcellus Shale, but from a shallower deposit. WENY-TV reported Tuesday that Chesapeake Energy is evaluating its natural gas wells in the area, and is taking corrective action. Chesapeake tested 26 residential wells within a half-mile radius of the river and found six of them in Wilmot Township had elevated methane levels. Methane was also detected in a crawl space of a seasonal home.

To: SusquehannaCoGasForum
Subject: Chesapeake Responds to Paradise Road Water Woes - by Cain Chamberlin - 8/12/2010

This 1,100-gallon tank was purchased for Jared and Heather McMicken and their children to supply them with fresh water to bathe and do laundry until a solution is found for their contaminated water. Chesapeake provided these tanks for two neighbors as well—the Mike Phillips and Scott Spencer families—who are currently experiencing the same water issues as the McMickens. Photo by Cain Chamberlin.

Chesapeake Responds to Paradise Road Water Woes - by Cain Chamberlin - 8/12/2010

A streak of bad luck seems to be lingering over Jared and Heather McMicken of Paradise Road in Terry Township.

It all started in early June, when the couple discovered a strange, brown discoloration in their tap water. They still do not know what exactly is causing the disturbance as they are awaiting water test results from DEP. However, the DEP testing done in mid-July did find rising levels of methane in the well, which has now led to something the McMickens never saw coming.

Both of their next-door neighbors, the Mike Phillips and the Scott Spencer families, have the same discoloration in their water wells, which started about a month after the McMickens made that discovery. They all believed that a nearby Chesapeake gas drilling site was responsible for the sudden dilemma. Even though Chesapeake denied the claims at first, they are now taking action in a joint effort with DEP to solve the residents’ water problems.

Because of the increasing levels of methane in the water of each home, DEP installed an alarm device in the basement of each home. These devices are specifically designed to detect high amounts of methane that could be hazardous.

“We were told that if the alarms ever went off, we should call 911 immediately,” said Heather McMicken.

Early last Wednesday morning, their alarm went off, and the McMickens were consequently evacuated from their home as a precautionary measure.

“We made the call, and in no time DEP and Chesapeake were here,” she said. Since then, the McMickens and their two children have stayed at a hotel and also at the home of her mother until they feel safe enough to move back. They do make occasional stops at their home to pick up more clothes and necessities.

Meanwhile, DEP and Chesapeake have been on the property nearly every day trying to find an answer to the current predicament.

“Both are still doing all kinds of testing for us, and we are willing to welcome a third party to do tests too,” Jared McMicken explained.

During a meeting held late last week between Chesapeake and the Paradise Road residents, the company offered to have replacement water wells drilled for each home and purchase them all a temporary water source that they could use for bathing and washing clothes.

Hoses from an enormous 1,100-gallon tank are run through the house, replacing the old existing water pipes.

“We are very happy that they are taking care of the water problem,” said McMicken, “We are just trying to take a breather and wait for the test results to come back.”

Next-door neighbors Mike and Jonna Phillips are waiting on paperwork to look over and sign for a new water well. Their water issues began on July 12, and they finally had the temporary tank hooked up on Saturday. Before that, Jonna, who is seven months pregnant, drove to a friend’s house every day to shower. She is thrilled that she can finally wash clothes and bathe in her own home and is anxiously awaiting a new well. “Chesapeake is certainly trying to accommodate us better than before,” she said.

At the meeting with Chesapeake spokespersons, residents were also informed that there is ongoing testing to determine where the gas is coming from, and it was noted that the affected wells appear to be fed by the same aquifer.

Geologists were present at the meeting in an attempt to help explain aquifers, the type of rock formations in the area and how it may all relate to the potential movement of gas beneath the earth.

The Rocket-Courier has been communicating over the past week with Chesapeake Energy officials on the Paradise Road situation, posing a number of questions.

As of press time, there has been no response or statement.

September 13

DEP looks at drilling as river bubbles up

Chesapeake Energy operates several wells in the Bradford County area.

MATT HUGHES mhughes@timesleader.com

SUGAR RUN – Pennsylvania Department of Environmental Protection teams are investigating whether bubbles of methane gas that were discovered in the West Branch of the Susquehanna River last week are the product of natural gas drilling.

DEP Secretary John Hanger said his department has been working on the case since it first received reports of suspicious gas bubbles appearing in the river near Sugar Run in Bradford County Thursday afternoon. Three DEP teams were dispatched to the area Friday morning and will continue work through the holiday weekend, Hanger said.

DEP is also working with officials from Bradford County and Chesapeake Energy, which operates several wells in the area, including one about two miles from the section of the river where bubbling has been discovered, Hanger said.

Chesapeake Energy spokesman Brian Grove said in a statement Saturday that initial tests of the gas have revealed the presence of methane.

Hanger said that DEP is now attempting to trace the source of the gas. Methane sometimes appears naturally, Hanger said, but naturally occurring methane can be distinguished from methane that has been released as a byproduct of natural gas drilling through a testing process that Hanger likened to fingerprinting or DNA testing.

Grove said Chesapeake is also evaluating several of its wells in the vicinity to look for any conditions that might be a potential source of the methane. All nearby wells have been drilled but have not been hydraulically fractured, Grove added.

Hanger said DEP teams are also testing methane levels at homes and cabins in the area surrounding the appearance of the bubbles. Both free gas and well water are being tested, Hanger said.

Hanger said bubbles have been discovered in several places, and that DEP is investigating the area surrounding each site, but said he could not comment on how large an area DEP's investigation covers.

Chesapeake said it has also screened homes within a half mile of the sites and will continue screening throughout the weekend as a precautionary measure.

DEP will release a more detailed report on Tuesday, Hanger said.

Three drinking-water wells near a Chesapeake Energy gas well in Monroe Township, Bradford County were found to be polluted with methane gas after the lid blew off one of the water wells August 4.

DEP sent Chesapeake a "notice of violation" letter two days later, detailing action the company must take. Chesapeake did not claim responsibility for the contamination, but did supply affected residents with drinking water.

There are more than 850 gas wells in Bradford County, about half of which were drilled by Chesapeake, according to the county's website.

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Basement faults and seismicity in the Appalachian Basin of New York State

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Received 12 November 2001; accepted 26 April 2002

Abstract

Landsat lineaments identified by Earth Satellite Corporation (EARTHSAT, 1997) can be groundtruthed across the Appalachian Basin of New York State (NYS). Both fracture intensification domains (FIDs) and faults are observed in outcrop along the lineaments. Confirmation of deep structure associated with the surface structure is provided by both well log analyses and seismic reflection data (primarily proprietary). Additional faults are proposed by comparing the lineament locations with gravity and magnetic data. The result is a web of basement faults that crisscross New York State. By overlaying epicenter locations on the fault/lineament maps, it is possible to observe the spatial correlation between seismic events and the faults. Every seismic event in the Appalachian Basin portion of NYS lies on or near a known or suspected fault. It thus appears that not only are there more faults than previously suspected in NYS, but also, many of these faults are seismically active.

Keywords: Faults; Seismicity; Appalachian Basin; New York State

1. Introduction

The Appalachian Basin of New York State (NYS) has been regarded as generally structurally featureless except for a few well-acknowledged faults. For example, the NYS Geological Map (Rickard and Fisher, 1970) displayed only two sets of faults in the Appalachian Basin over a 450-km distance between Albany and Buffalo (Fig. 1): (1) N-trending faults in the Mohawk Valley region that were believed to be Ordovician in age (e.g., Bradley and Kidd, 1991) and (2) several E- and N-striking short faults in the Finger Lakes region (central NYS). Other faults recognized in NYS include (from west to east, Fig. 1): (1) the Bass Island Trend (e.g., Van Tyne and Foster, 1979; Beinkafner, 1983), (2) the Clarendon–Linden Fault System (CLF; e.g., Chadwick, 1920; Van Tyne, 1975; Fakundiny et al., 1978; Jacobi and Fountain, 1993, 1996, 2002), (3) an Ordovician-aged, N-striking, normal fault east of the CLF (Rickard, 1973), (4) NNE-striking normal faults at Keuka Lake (Murphy, 1981), (5) Alleghanian folds, thrusts/normal faults, and tear faults in the Southern Tier of NYS (Bradley et al., 1941; Murphy, 1981), and (5) three Ordovician-aged horsts and graben with assumed N-strikes in central NYS (Rickard, 1973). Thus, less than 10 fault systems had been identified across a 450-km swath in the Appalachian Basin of NYS, and

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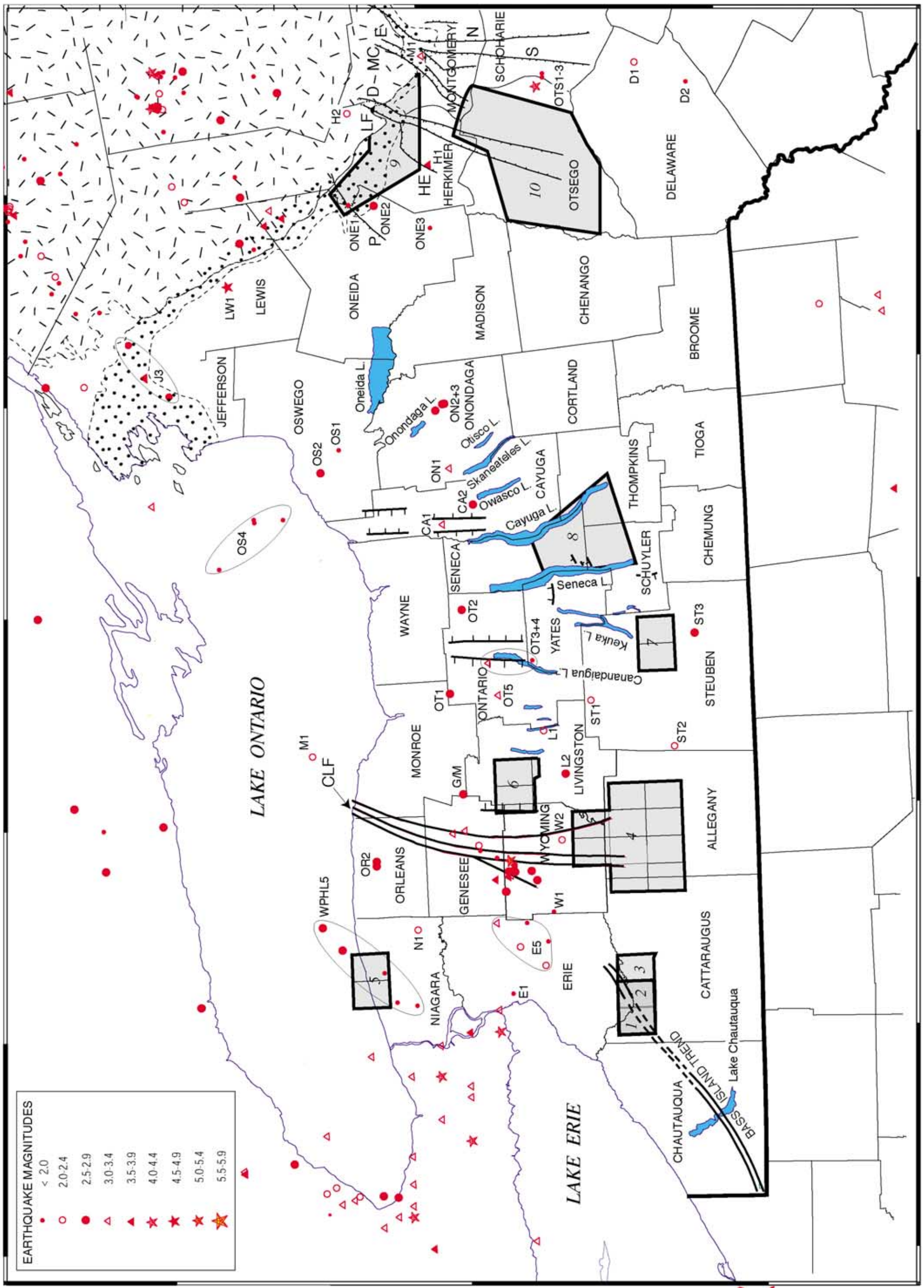

EARTHQUAKE MAGNITUDES
< 2.0
2.0-2.4
2.5-2.9
3.0-3.4
3.5-3.9
4.0-4.4
4.5-4.9
5.0-5.4
5.5-5.9
LAKE ONTARIO
LAKE ERIE
CLF
BASS ISLAND TREND
Lake Chautauqua
50 MILES
50 KM
-80
-79
-78
-77
-76
-75
44
43
42
NIAGARA
ORLEANS
GENESEE
ERIE
WYOMING
MONROE
LIVINGSTON
ONTARIO
WAYNE
SENECA
YATES
STEUBEN
ALLEGANY
CATTARAUGUS
CHAUTAUQUA
SCHUYLER
CHEMUNG
TIOGA
THOMPKINS
CAYUGA
CORTLAND
ONONDAGA
OSWEGO
JEFFERSON
LEWIS
ONEIDA
MADISON
CHENANGO
BROOME
DELAWARE
OTSEGO
HERKIMER
MONTGOMERY
SCHOHARIE
Oneida L.
Onondaga L.
Otisco L.
Skaneateles L.
Owasco L.
Cayuga L.
Seneca L.
Keuka L.
Canandaigua L.

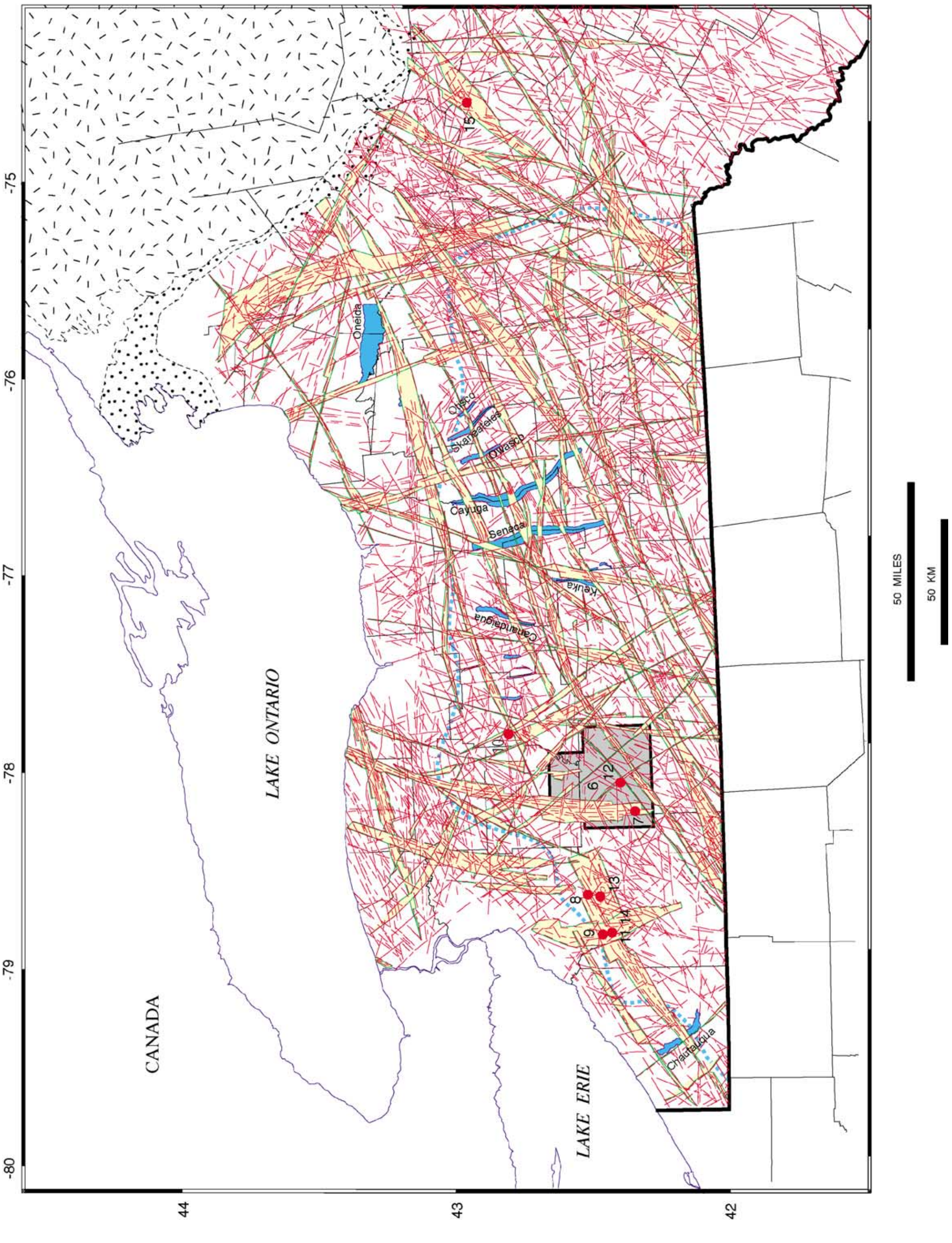
only one of these, the CLF, was regularly acknowledged. There were indications that this low number of faults might not be a true representation, based on the lineaments recognized by Isachsen and McKendree (1977), but the standard belief was that essentially little faulting characterized the Appalachian Basin of NYS. Nevertheless, the northern tier of the Appalachian Basin in NYS did exhibit sporadic seismicity (Fig. 1). The question then becomes: are these seismic events associated with faults that have not been recognized, or are the seismic events essentially spatially random, with no predictive structural control?

In the late 1980s and early 1990s, several studies in nearby regions of assumed flat-lying units began to demonstrate that basement faults did exist in much greater numbers than previously suspected, and that these faults had been repeatedly reactivated. For example, in the Illinois Basin and bordering areas, faults that penetrate the Precambrian basement appeared to have been active for much of the geological record that can be observed (e.g., Kolata and Nelson, 1991; Nelson and Marshak, 1996). In eastern Ohio, the NW-striking Highlandtown Fault experienced episodic motion from Cambrian to Pennsylvanian (Root, 1992; Riley et al., 1993; Root and Onasch, 1999), and may follow a Precambrian fault (Root and Onasch, 1999). Other faults in Ohio (e.g., the N-striking Bowling Green Fault) also show a long-lived, complex fault motion history (e.g., Onasch and Kahle, 1991). In Pennsylvania, NW-striking structures that are orthogonal to the Appalachian orogen [“cross-strike discontinuities” (CSDs)] are assumed to be Precambrian faults that were reactivated in the Phanerozoic (e.g., Harper, 1989). These CSDs were the continental extension of transform faults during Iapetan rifting; later, they exerted control on sedimentation patterns, and the CSDs completed their Paleozoic history as guides for tear faults during the development of Alleghanian thrusting (e.g., Kowalik and Gold, 1976; Shumaker and Wilson, 1996; Gold, 1999). In northwestern Pennsylvania, NW-striking CSDs were proposed to intersect Cambrian Rome Trough faults, resulting in a kaleidoscope of fault blocks that have reactivated episodically (e.g., Harper, 1989; Riley et al., 1993; Beardsley et al., 1999; Harper et al. 1999). A similar scenario of fault blocks was proposed for western NYS (Fakundiny et al., 1978). Sanford et al. (1985) also proposed that the Paleozoic Platform rocks in Ontario were chopped by numerous faults. More recent work in Ontario has supported their original premise of multiple faults and faulting events (e.g., Sanford, 1993; Eyles et al., 1993; Thomas et al., 1993; Mohajer, 1993; Wallach et al., 1998). In 1989, Jacobi and Fountain (1996, 2002) began detailed multidisciplinary investigations on the CLF in western NYS. They too found evidence for multiple faults with a long history of semi-independent fault motion through the early Paleozoic (e.g., Jacobi and Fountain, 1993, 1996, 2002).

Part of the CLF multidisciplinary approach developed by Jacobi and Fountain (1996) was the identification of fracture intensification domains (FIDs; e.g., Jacobi and Xu, 1998; Jacobi and Fountain, 2001, 2002). The FIDs are characterized by closely spaced fractures, the strike of which defines the trend of the FID. The closely spaced fractures are also commonly the master fractures, even though they may characteristically abut other fracture sets in regions outside the FID. In interbedded shales and thin sandstones in NYS, fractures within the FID that parallel the FID characteristically have a fracture frequency greater than 2/m, and commonly the frequency is an order of magnitude greater than in the region surrounding the FID.

Certain sets of FIDs are marked by soil gas anomalies commonly less than 50 m wide (Jacobi and Fountain, 1993, 1996; Fountain and Jacobi,

Fig. 1. Index map with seismic events. Shaded areas indicate where the UB Rock Fracture Group has conducted research. 1=unpublished data; 2=Jacobi and Baudo (1999), Baudo and Jacobi (1999, 2000); 3=Tober and Jacobi (2000); 4=Jacobi and Fountain (1993, 1996, this volume); 5=Harper and Jacobi (2000); 6=unpublished data (Akzo–Nobel Salt); 7=Paquette et al. (1998); 8=Lugert et al. (2001, 2002), Jacobi et al. (2002b); 9=Jacobi (1981), Jacobi et al. (1996); Jacobi and Mitchell (2002); 10=Jacobi and Smith (2000). CLF=Clarendon–Linden Fault System, generalized fault trace from Van Tyne (1975). Bass Island Trend trace modified from Van Tyne and Foster (1979). Remainder of the faults (with hachures) are faults (after Rickard, 1973) that were assumed to be Ordovician-aged [Saukian Sequence of Rickard (1973)]. For faults in the Mohawk Valley, D=Dolgeville Fault; E=Ephrata Fault; HE=Herkimer Fault; LF=Little Falls Fault; MC=Mothers Creek Fault; N=Noses Fault; P=Prospect Fault; S=Sprakers Fault. Epicenters are from Jacobi and Fountain (1996). Labeled epicenters are discussed in the text.


-75
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43
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CANADA
LAKE ONTARIO
LAKE ERIE
Oneida
Otisco
Skaneateles
Owasco
Cayuga
Seneca
Keuka
Canandaigua
Chautauqua
15
10
6
12
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9
11
14
50 MILES
50 KM

2000). In NYS, the background methane gas content in soil is on the order of 4 ppm, but over open fractures in NYS, the soil gas content increases to 40–1000+ ppm.

Most FIDs are coincident with lineaments observed in remote sensing data (e.g., Jacobi and Fountain, 1996, 2002; Jacobi et al., 2002a). These lineaments include straight stream and valley segments observed on 7.5′ topographic maps and digital elevation maps (DEMs). Short lineaments (< ~ 100 m) on topographic maps are aligned parallel to fractures, but not necessarily to FIDs. In contrast, longer lineaments (on the order of 0.5 km and longer) commonly correspond to FIDs in outcrop. Jacobi and Fountain (1996) also identified lineaments on air photos and Landsat images. On the air photos, both topographic and tonal lineaments were identified, whereas lineaments on the Landsat images were tonal based. Jacobi and Fountain (1996) also used side-looking aperture radar (SLAR) and Fountain et al. (1999) flew low-level (high-resolution) hyperspectral imaging. In both data sets, FIDs in outcrop occurred along the long tonal lineaments.

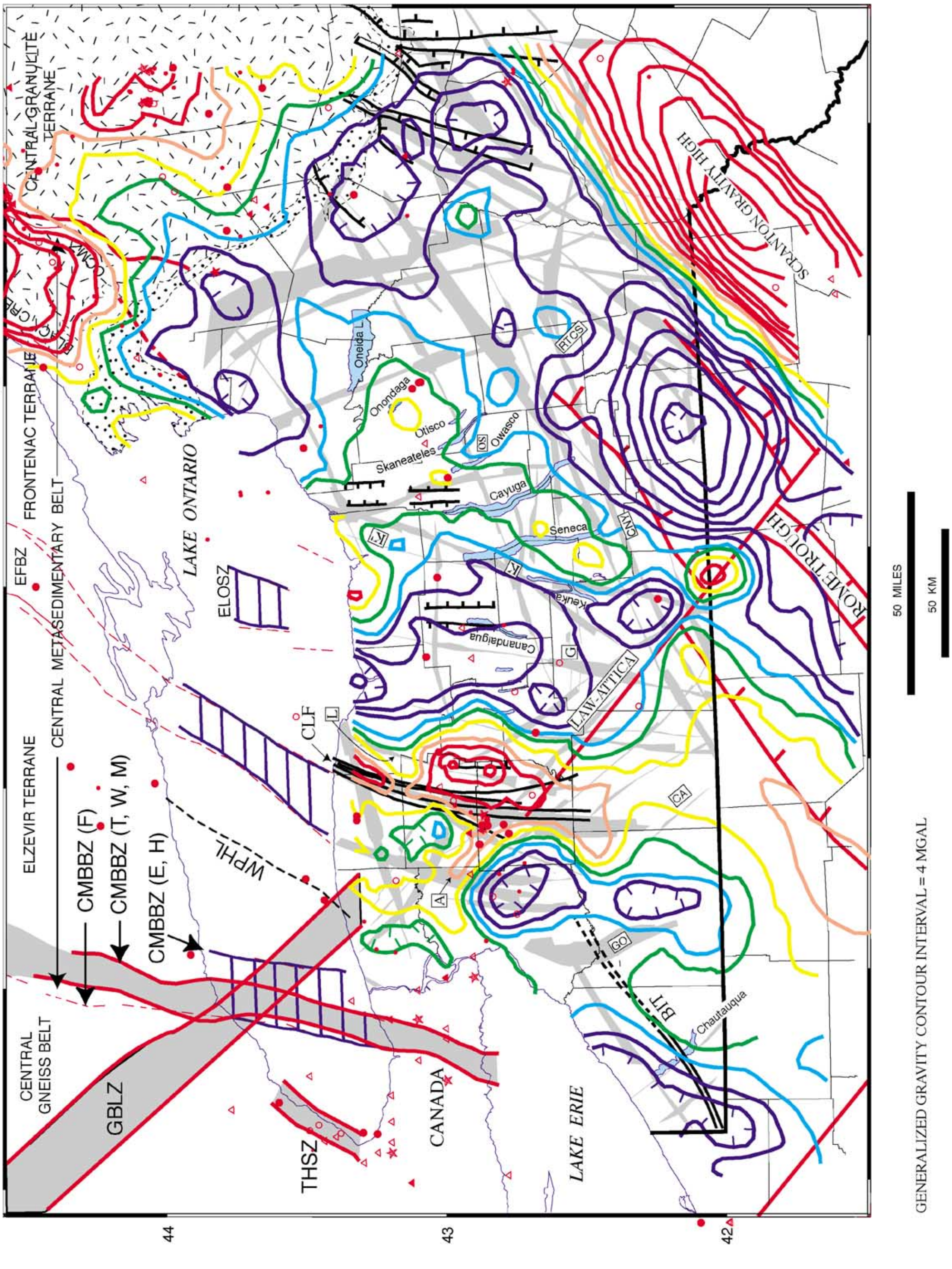
FIDs are particularly useful in that they generally mark the location of nearby faults that can be identified on the basis of stratigraphic displacements inferred from outcrops, well logs, or seismic reflection data (e.g., Jacobi and Fountain, 2002). Moreover, faults with small offset commonly occur in outcrops within an FID. Thus, by identifying lineaments, and groundtruthing the lineaments, it is possible to predict the location and extent of subtly expressed faults that were previously overlooked.

Perhaps the single most important study that advanced the recognition of faults in NYS was the identification of lineaments in 1997 by Earth Satellite Corporation (EARTHSAT) on Landsat Thematic Mapper (TM) images (“E97 lineaments”, Fig. 2). After resampling and enhancing TM bands 2, 4, and 7, EARTHSAT (1997) identified tonal and stereoscopic (topographic) lineaments on the enhanced images by “eye”. Fig. 2 also shows a more generalized set of lineaments, based on bundling the EARTHSAT (1997) lineaments that were relatively long and/or closely spaced. In all areas where the UB Rock Fracture Group has conducted field research (Fig. 1), a clear association of FIDs and lineaments was recognized. This paper deals with the following regional sets of lineaments:

(1) those that strike NS and are related to Precambrian basement trends,
(2) those that arc across NYS, from NE-striking in western NYS to E-striking in central and eastern NYS; these lineaments are related to both assumed Iapetan rift/Rome Trough trends and to Alleghanian thrust tectonics,
(3) CSDs which trend NW in western NYS and trend both NW and NS in central NYS, and
(4) those with miscellaneous strikes and sources.

Fundamental to establishing a relationship between seismicity and faults is to first identify which lineaments indicate faults, and then to determine to what extent a spatial relationship exists between the faults and earthquake epicenters. Evidence utilized for recognition of faults in NYS included the integration of FIDs, E97 lineaments (Fig. 2), topographic lineaments, gradients in gravity and magnetic data (Figs. 3 and 4, respectively), seismic reflection profiles, and well logs. Integration of these data sets promoted the identification of numerous faults in the study area (Fig. 5). This paper illustrates the evidence for the confirmed faults, and demonstrates the characteristics and ubiquity of the faults for western, central, and eastern NYS (Sections 2, 3, and 4, respectively). Suspected faults, those that are not confirmed by outcrop structures, well logs or seismic reflection profiles, are discussed in Appendix A. Section 5 of the paper examines the spatial distribution of seismic events in NYS in relation to the distribution of the known and suspected faults.

Fig. 2. Map of Landsat lineaments. Lineaments (red lines) were identified from Landsat images by EARTHSAT (1997). Generalized lineaments (lineament “bundles”, in yellow) were selected based on the density of EARTHSAT’s (1997) lineaments and the continuous nature of the lineaments. Dashed blue line indicates the extent of Silurian salt (zero-line of the salt isopach), from Kreidler (1957) and NYSERDA (unpublished data). Large dots indicate the general site of features shown in following figures; number adjacent to the dot indicates the figure number in which the feature appears. Shaded box with annotation “6” indicates location of Fig. 6.


CENTRAL GRANULITE TERRANE
FRONTENAC TERRANE
CENTRAL METASEDIMENTARY BELT
ELZEVIR TERRANE
CENTRAL GNEISS BELT
EFBZ
CMBBZ (F)
CMBBZ (T, W, M)
CMBBZ (E, H)
GBLZ
THSZ
WPHL
CLF
ELOSZ
LAKE ONTARIO
LAKE ERIE
CANADA
Oneida L.
Onondaga
Otisco
Skaneateles
Owasco
Cayuga
Seneca
Keuka
Canandaigua
Chautauqua
RTCS
CNY
LAW-ATTICA
BIT
GO
CA
SCRANTON GRAVITY HIGH
ROME TROUGH
50 MILES
50 KM
-75
-76
-77
-78
-79
-80
44
43
42
GENERALIZED GRAVITY CONTOUR INTERVAL = 4 MGAL

2. Western New York fault systems

2.1. N-striking faults

In western NYS, strong evidence has been collected for five N-striking fault systems: the South Branch Fault, the West Valley Fault System, the CLF, the Leroy Fault, and the Retsof Fault (Fig. 5). The most prominent fault system is the seismically active CLF (e.g., Fakundiny et al., 1978), the details of which are presented in Jacobi and Fountain (2002). Thus, a brief discussion herein is sufficient. In the northern half of western NYS, the CLF is located along the western flank of a gravity high and along a magnetic anomaly (Figs. 3 and 4; see also Diment et al., 1980). Lineaments identified by EARTHSAT (1997) generally lie along the western faults of the CLF (Fig. 2). The CLF marks the eastern boundary of the Elzevir–Frontenac Boundary Zone (EFBZ, Fig. 5), an intra-Grenvillian suture (e.g., Forsyth et al., 1994).

In Allegany County, the CLF consists of at least 10 parallel zones of FIDs (Fig. 6; Jacobi and Fountain, 1996, 2002). Most of these FIDs correspond to demonstrable faults that are segmented by NW-striking CSDs. The Rawson Valley Fault (Figs. 6 and 7) typifies the confirmatory data for the faults of the CLF. The N-striking Rawson Valley (Fig. 6) is coincident with E97 lineaments (Fig. 2), and both coincide with N-striking FIDs and deep faults imaged on seismic reflection profiles (Fig. 7). Variations in reflector interval thicknesses observed on seismic reflection profiles in Allegany County demonstrate that fault segments of the CLF have different reactivation histories, but all segments show Iapetan rift activity and Taconic slip (Jacobi and Fountain, 2002).

West of the CLF, several N-striking, parallel E97 lineaments extend south from Lake Ontario, where they are on strike with the western boundary of the Elzevir–Frontenac Boundary Zone in Lake Ontario (EFBZ, Figs. 2 and 5). This fault system, here named the West Valley Fault System (Fig. 5), continues into Cattaraugus County, where the lineaments become less abundant and less continuous (Fig. 2). Tober and Jacobi (2000) found N-striking FIDs (Fig. 8) coincident with the westernmost N-striking lineament (location #8 in Fig. 2). Several other FIDs to the east suggest that a zone of N-striking faults passes through the area. Seismic reflection profiles across this trend reveal faults that affect Ordovician reflectors (Steiner, personal communication, 2001).

The South Branch of Cattaraugus Creek Fault (Fig. 5) is defined by (1) a set of N-striking E97 lineaments that extend south to location #9 in Fig. 2, (2) a narrow, high amplitude magnetic anomaly ("SB" in Fig. 4b), and (3) FIDs and two parallel en echelon N-striking faults exposed in the South Branch of Cattaraugus Creek (Fig. 9; location #9 in Fig. 2; Jacobi and Baudo, 1999). The nature of the N-striking faults is illustrated at location #9 (Fig. 2), where N-striking faults are truncated by NW-striking master fractures (Fig. 9a). Because unweathered surfaces on these NW-striking fracture do not display brittle shear structures, the apparent fault offset of the N-striking faults across the NW-striking fractures does not imply slip along the NW-striking fractures; rather, the NW-striking joints developed before (or coeval with) the segmented N-striking faults. Further support for this interpretation is provided by scanline and scangrid data, which show that the N-striking fractures of the FID associated with the N-striking faults have a curving-parallel (abutting) relationship with the NW-striking master fracture (Fig. 9a).

Fig. 3. Map showing the relationship among gravity anomalies, generalized lineament bundles, and proposed faults outside NYS. Generalized Bouguer gravity from National Geophysical Data Center (NGDC), Revetta and Diment (1971), and Revetta (1991). Contour interval is 4 mgal. Red is high; blue and purple are low. Shaded zones are the generalized selected lineaments from Fig. 2. Seismicity and black faults in NYS are the same as in Fig. 1 Annotated anomalies are discussed in text. BIT=Bass Island Trend; CMBBZ=Central Metasedimentary Belt Boundary Zone; EFBZ=Elzevir–Frontenac Boundary Zone; ELOSZ=Eastern Lake Ontario Shear Zone (Hutchinson et al., 1993); GBLZ=Georgian Bay Linear Zone (Wallach, 1990); THSZ=Toronto–Hamilton Seismic Zone (Mohajer, 1993); WPHL=Wilson–Port Hope Lineament (Mohajer, 1993; Thomas et al.,1993). For the EFBZ, the boundaries in black in Lake Ontario are from Hutchinson et al. (1993); the red dashed boundaries are from Forsyth et al. (1994). For the different proposed boundaries of the CMBBZ, E=Eyles et al. (1993), F=Forsyth et al. (1994), H=Hutchinson et al. (1993), M=Mohajer (1993), and T=Thomas et al. (1993). Magnitude symbols of epicenters are the same as those in Fig. 1. Red hachured lines indicate normal faults related to Rome Trough development and NW-striking red lines in New York and Pennsylvania indicate cross-strike discontinuities (from Harper, 1989).

Jacobi and Baudo (1999) therefore suggested that the N-striking faults in outcrop and FIDs postdate the (assumed) Alleghanian NW-striking fractures.

North-striking faults in western NYS also have been identified east of the CLF, including the "Leroy" and "Retsof" faults (new names). The Leroy Fault (Fig. 1) was first proposed by Rickard (1973) from well logs that implied an Ordovician growth-fault with a down-on-the-east sense of offset. This fault corresponds to N-striking E97 lineaments (Fig. 2) that lie along the eastern flank and center of a gravity high that also tracks the CLF (labeled "L" in Fig. 3). The coincident gravity gradient suggests that the Leroy Fault affects the Precambrian basement similar to the parallel CLF.

East of the Leroy Fault N-striking FIDs, faults, lineaments, and stratigraphic data suggest that a N-striking fault system (Retsof Fault) is located in the vicinity of Retsof/Griegsville (location #10 in Fig. 2). Closely spaced, N-striking master fractures define N-striking FIDs in a 10-km long, N-striking valley (Fig. 10a and b). Other N-striking structures exposed in the valley include locally west-dipping thrust ramps between duplex flats (site 4 in Fig. 10a and Fig. 10c). Jacoby (1969) also identified a N-striking, low-angle thrust beneath the valley in the Silurian salt section, based on (1) elevations of a salt horizon in diamond drill holes, (2) isopach maps, and (3) exposures in the Retsof salt mine.

Away from the valley floor, other fracture sets are dominant and master; the N-striking fractures are essentially nonexistent except for a few narrow zones, as seen in both Spezzano and Tauton gullies west of the N-striking valley (Fig. 10a). However, additional discrete zones of N-striking FIDs and lineaments (e.g., Fig. 10) suggest that a series of parallel N-striking faults occur in an approximately 8-km wide swath that is centered about 2 km east of the location of Fig. 10. The fault system defined by this swath extends north of the valley at least 10 km, based on N-striking stream and slope lineaments, and E97 lineaments suggest that the fault system extends north to Lake Ontario.

The preceding discussion demonstrates that most of the major N-striking lineaments in western NYS are groundtruthed, except for N-striking lineaments in Chautauqua County and Cattaraugus counties. Several N-striking faults are suspected in these areas, based on E97 lineaments, as well as gravity and magnetic gradients. These faults include the Charlotte Center Fault and the Franklinville–Five Mile Fault System, both of which are discussed in Appendix A.

2.2. NE-striking faults

Several researchers have recognized NE-striking faults and folds of assumed Alleghanian age in western New York. The data utilized for identification included the following.

(1) Well logs (Bradley et al., 1941; Van Tyne and Foster, 1979; Van Tyne et al., 1980a,b,c,d,e; Murphy, 1981; Jacobi and Fountain, 1993, 1996).

(2) Seismic reflection profiles (e.g., Jacobi and Fountain, 1993, 1996, 2002b).

(3) Level lines of bedding surfaces (Wedel, 1932).

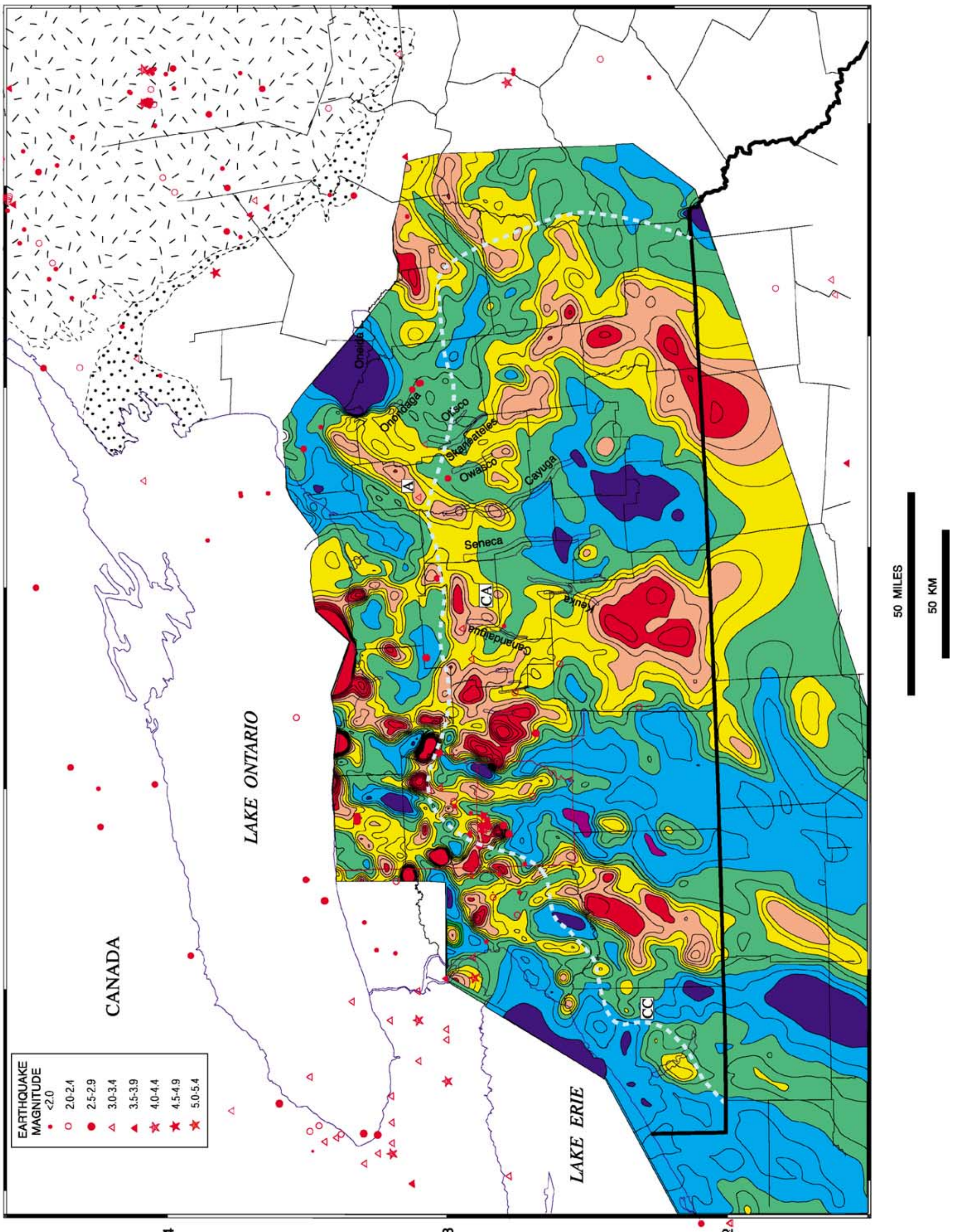
(4) Outcrop stratigraphy (e.g., Bradley et al., 1941).

(5) FIDs (Jacobi and Fountain, 1996; Jacobi and Xu, 1998) and other outcrop structure, including exposed moderately dipping thrusts, meso-scale duplexes, stacks of bedding plane thrusts ("flats") marked by bedding restricted melange and pencil cleavage, and recumbent folds (Jacobi and Zhao, 1996; Jacobi and Fountain, 1996; Zack and Jacobi, 1997).

Prominent topographic and E97 lineaments mark these fault zones. The fact that the generally N-striking Precambrian-sourced magnetic anomalies are modified in regions where the NE-trending lineament bundles cross the magnetic anomalies suggests that some of the lineaments also mark older faults that affected the Precambrian basement.

The Bass Island Trend is a series of northwesterly directed Alleghanian thrusts that ramp upsection at the zero-line of the Silurian salt isopach (Fig. 5). The Bass

Fig. 4. (a) Map of magnetics. Magnetics from the Ohio Geological Survey and United States Geological Survey (Zietz, 1982). Red is high, blue is low. Dashed blue line is the zero-line of the Silurian salt isopach (from Kreidler, 1957 and NYSERDA, unpublished data). LAW-ATTICA=Lawrenceville–Attica Lineament. Annotated anomalies discussed in the text. (b) Map showing the relationship among magnetics, selected generalized EARTHSAT (1997) lineaments, and seismicity. Magnetics from Fig. 4a, selected generalized EARTHSAT (1997) lineaments from Fig. 2, and seismicity from Jacobi and Fountain (1996). Annotated anomalies are discussed in the text.


EARTHQUAKE MAGNITUDE
<2.0
2.0-2.4
2.5-2.9
3.0-3.4
3.5-3.9
4.0-4.4
4.5-4.9
5.0-5.4
CANADA
LAKE ONTARIO
LAKE ERIE
Oneida
Onondaga
Otisco
Skaneateles
Owasco
Cayuga
Seneca
Keuka
Canandaigua
A
CA
CC
-75
-76
-77
-78
-79
-80
44
43
42
50 MILES
50 KM

(a)

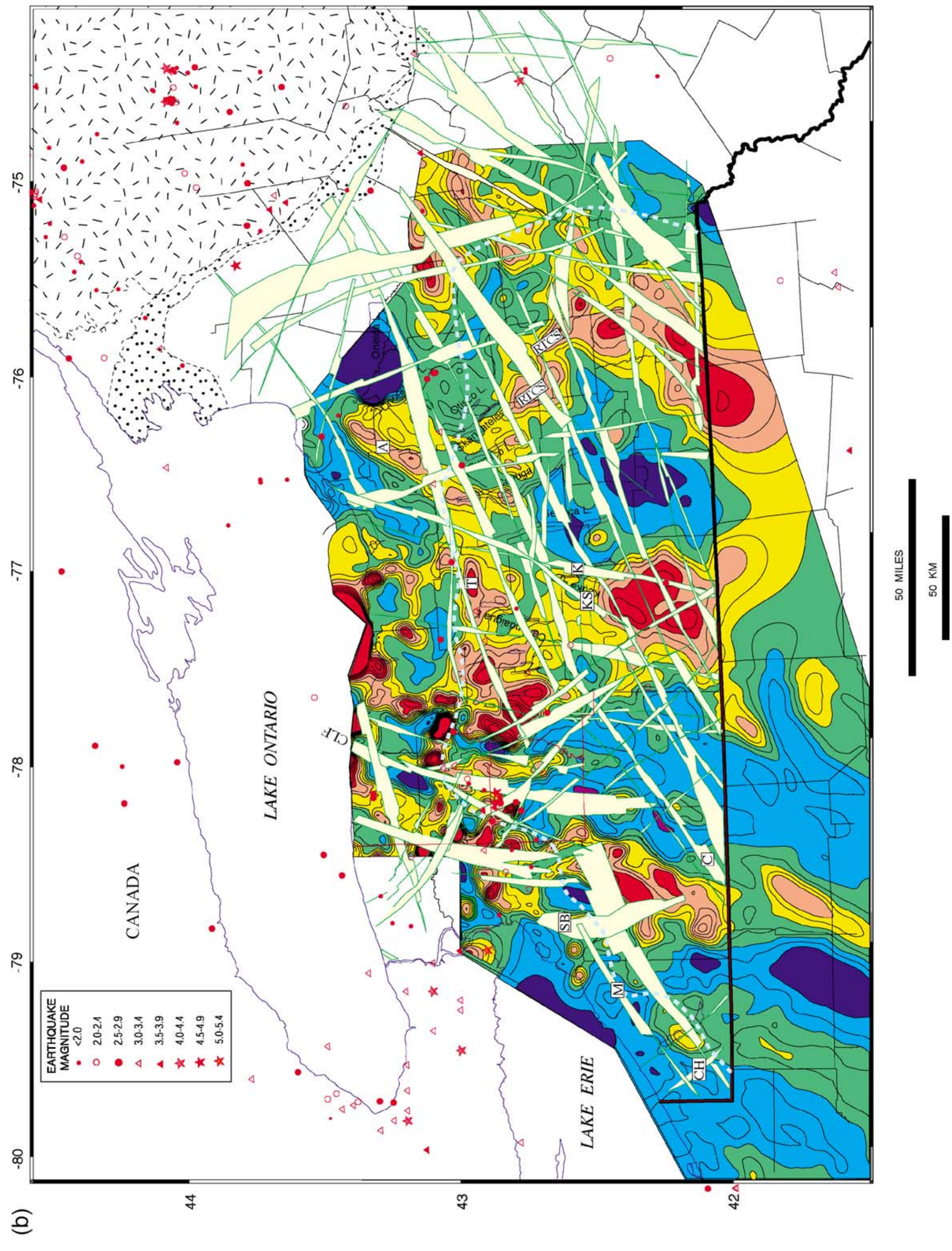


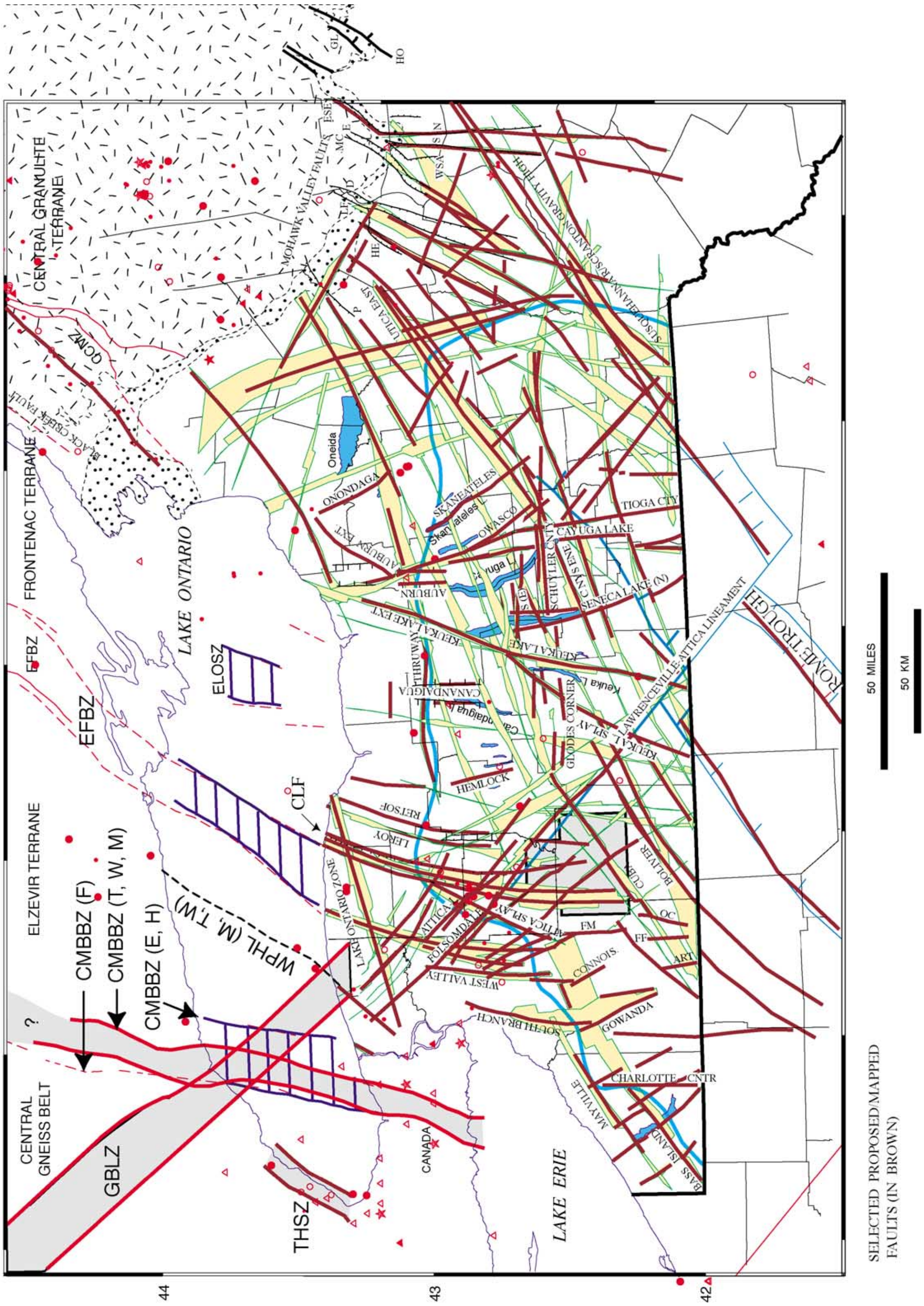
Fig. 4 (*continued*).

Island Trend was first recognized from well logs that indicated anomalous formation elevations and repeated sections (Van Tyne and Foster, 1979; Beinkafner, 1983). More recent well log analyses confirmed the existence of these faults and showed that (1) the fault segments are linked by CSDs, and (2) additional thrust ramps are probable both to the southeast and northwest of the presently recognized Bass Island Trend (Jacobi et al., 2001a).

Lineaments identified by EARTHSAT (1997) are coincident with the Bass Island Trend where it has been identified in southwestern Chautauqua County and Erie County (solid portions of the Bass Island Trend in Fig. 1). The E97 lineaments continue along the dashed line that joins the two known sections of the Bass Island Trend (Fig. 1). However, Loewenstein (personal communication, 2000) believed that repeated sections are absent in well logs in the area of the dashed line. If Loewenstein is correct, then an apparent conflict exists between the lineaments and the well logs. One resolution is that small thrusts exist in the region of the dashed line, and are manifested in surface rocks by the NE-striking FIDs and kinks/thrust faults (Fig. 11; Jacobi and Baudo, 1999; Baudo and Jacobi, 1999, 2000). The main thrust ramps in the dashed region would be located farther northwest along the "Mayville Fault" zone (labeled "M" in Fig. 4b, and discussed in Appendix A).

A second explanation suggests that the E97 lineaments are coincident not only with the Bass Island Trend, but also with possible reactivated Iapetan rift/Rome Trough (?) faults that controlled the margin of the Silurian salt basin. In this model, although the main thrust ramps would be located to the northwest along the parallel Mayville Fault (discussed in Appendix A), reactivation of the Iapetan rift faults in the Precambrian basement resulted in lineaments along the dashed potion of the Bass Island Trend. Support for the concept of NE-striking faults that affected Precambrian basement comes from both gravity and magnetic anomalies, which change character where the NE-striking Bass Island Trend crosses the geopotential anomalies (Figs. 3 and 4). For example, the narrow, N-striking magnetic high associated with the South Branch of Cattaraugus Creek Fault at location 9 (Figs. 2, 4a, "SB" on Fig. 4b) terminates where the salt zero-line (associated with the Bass Island Trend) crosses the magnetic anomaly. Similar effects are apparent in the gravity data in both westernmost and eastern Chautauqua County where the N-trending gravity low and high (respectively) hook to the northeast where the Bass Island Trend crosses the anomalies (Fig. 3). These effects could not result from the minimal density differences from the thrust sediments; rather it appears that the N-striking Precambrian basement structural blocks were modified by later NE-striking faults. The supposition that the NE-striking Precambrian basement faults may have been related initially to Iapetan rifting is based on the parallelism of the NE-striking faults to the presumed Iapetan rift faults and Rome Trough trends in NYS (e.g., Figs. 3 and 5) and to seismic reflection profiles across the nearby CLF that show evidence of Iapetan rift activity (Jacobi and Fountain, 2002). These same arguments are the basis for possible Iapetan rift activity along other faults in the following discussions.

Another NE-striking fault system is the Cuba Fault (new name), which is based on a NE-striking EARTHSAT (1997) lineament bundle, coincident magnetic gradients in Allegany and Cattaraugus counties (labeled "C" in Fig. 4b, and "Cuba" in Fig. 5), FIDs, and well log analyses. In Allegany County, E97 lineaments of the Cuba Fault correspond to the NE-trending Black Creek Valley (Fig. 6), along which NE-striking FIDs occur (Jacobi and Fountain, 1996). Well log analyses demonstrated up to 62.5 m (200 ft) stratigraphic offset on the Onondaga Formation across Black Creek Valley (Van Tyne et al., 1980a,b,c,d,e; Jacobi and Fountain, 1993, 1996), and detailed surface stratigraphy demonstrated surface bedrock offset consistent with the well log analyses (Jacobi and Fountain, 1996). The offset Devonian units suggested that the fault is Alleghanian. Most Alleghanian faults in the Appalachian Basin of NYS were thought to be related to decollement on the Silurian salt (e.g., Prucha, 1968); however, in eastern Cattaraugus County, a magnetic gradient parallels the E97 lineament bundle of the Cuba Fault, and this magnetic gradient truncates a generally N-striking magnetic high (east of "C" in Fig. 4b). The association with magnetic anomalies suggests that the Cuba Fault system may affect Precambrian basement. The trend is parallel to the proposed trend of the Rome Trough and related faults (Fig. 5), and therefore deeper


CENTRAL GRANULITE TERRANE
FRONTENAC TERRANE
ELZEVIR TERRANE
CENTRAL GNEISS BELT
GBLZ
CMBBZ (F)
CMBBZ (T, W, M)
CMBBZ (E, H)
WPHL (M, T,W)
THSZ
EFBZ
ELOSZ
CLF
LAKE ONTARIO
LAKE ERIE
CANADA
MOHAWK VALLEY FAULTS
Oneida
ROME TROUGH
LAWRENCEVILLE-ATTICA LINEAMENT
SUSQUEHANNA/SCRANTON GRAVITY HIGH
UTICA EAST
ONONDAGA
SKANEATELES
OWASCO
AUBURN
TIOGA CTY
CAYUGA LAKE
SENECA LAKE (N)
KEUKA LAKE
CANANDAIGUA
HEMLOCK
GLODES CORNER
RETSOF
LEROY
ATTICA SPLAY
FOLSOMDALE
WEST VALLEY
SOUTH BRANCH
GOWANDA
CHARLOTTE CNTR
MAYVILLE
BASS ISLAND
CONNOIS
LAKE ONTARIO ZONE
CUBA
BOLIVAR
-75
-76
-77
-78
-79
-80
44
43
42
50 MILES
50 KM
SELECTED PROPOSED/MAPPED FAULTS (IN BROWN)

portions of the fault system may have an Iapetan rift/ Rome Trough origin.

2.3. NW-striking faults

Northwest-striking faults have been recognized in both Allegany and Cattaraugus counties. In Allegany County Jacobi and Fountain (1996, 2002), delineated NW-striking fault zones on the basis of exposed structures and lineaments observed on 7.5′ topographic maps, air photos and Landsat images (Figs. 2 and 6). In outcrop, the fault zones were recognized by NW-striking FIDs and steeply dipping step faults, each with minimal (<10 cm), down-on-the-southwest stratigraphic offset (Fig. 12). Rare cross-fault markers, such as ripple marks, indicate minimal (<10 cm) left-lateral motion. Fakundiny et al. (1978) hypothesized a similar sense of stratigraphic offset for NW-striking zones elsewhere in western New York. The NW-striking faults offset many of the NE-striking faults, suggesting the NW-striking faults were utilized as tear faults/lateral ramps/transfer zones during development of the NE-striking faults. The NW-striking faults also truncate the N-striking CLF faults that are anchored in Precambrian-basement (Jacobi and Fountain, 1996, 2002). This linkage between deep NW-striking faults and shallower tear faults has been proposed for similar faults in Pennsylvania (Kowalik and Gold, 1976; Shumaker and Wilson, 1996; Gold, 1999).

Several NW-striking fault zones were demonstrated in Cattaraugus County on the basis of a few NW-striking E97 lineaments (Fig. 2) coupled with more recent detailed structural, stratigraphic, soil gas, well log, and lineament analyses (Baudo and Jacobi, 1999, 2000; Jacobi and Baudo, 1999; Jacobi et al., 2001a; Tober and Jacobi, 2000; Nelson et al., 2002). For example, the Connoisarauley Fault (Fig. 5) was defined by Tober and Jacobi (2000) on the basis of the 14-km long, NW-striking Connoisarauley Valley, which exposes NW-striking FIDs (Fig. 13) and small-offset step faults. To the west, NW-striking FIDs (Fig. 14; Jacobi and Xu, 1998; Jacobi and Baudo, 1999; Baudo and Jacobi, 1999, 2000) coincide with NW-striking topographic lineaments (the "Gowanda" NW-striking faults in Fig. 5). Because some of the NW-striking faults are associated with magnetic lineaments, and many faults appear to be coincident with truncations of N-striking gravity and magnetic anomalies, these NW-striking faults may affect Precambrian basement. For example, N-striking gravity and magnetic anomalies change trend in the area of NW-striking lineament bundles "GO" and "CA" (Fig. 3). Additional suspected NW-striking faults, located in Chautauqua County and along the Lawrenceville–Attica lineament and extensions (Fig. 5), are discussed in Appendix A.

3. Central New York fault systems

3.1. N- and NNE-striking faults

A number of NNE-striking faults in central NYS has been identified based on well log analyses, Landsat lineament studies and recent integration of outcrop structure, soil gas, and topographic data. Suspected faults, based on E97 lineaments coincident with geophysical gradients, are discussed in Appendix A. Rickard (1973) proposed an Ordovician, N-striking horst (here called the Canandaigua Lake faults) along the east side of Canandaigua Lake (Fig. 1) on the basis of anomalous formation elevations on one well log. The southern part of the proposed horst coincides with a N-striking magnetic high (labeled "CA" in Fig. 4a), suggesting Precambrian basement involvement. That no E97 lineaments are associated with the horst could indicate merely that the E97 data do not identify existing N-striking lineaments in this area, such as the northern part of Canandaigua. Alternatively, an approximately east–west trend of the horst is also

Fig. 5. Map showing the relationships among selected generalized lineaments, known and proposed faults, and seismicity. Sources and symbols of faults and lineaments outside NYS are the same as in Fig. 3. For faults in the Mohawk Valley, HE=Herkimer Fault; P=Prospect Fault; LF=Little Falls Fault; D=Dolgeville Fault; MC=Mothers Creek Fault; E=Ephrata Fault; ESA=East Stone Arabia Fault; S=Sprakers Fault; N=Noses Fault; WSA=West Stone Arabia Fault; HO=Hoffmans Fault. Abbreviations for other faults: ART=Allegheny River/Tuna Creek Fault, FF=Five Mile/Four Mile Fault, FM=Franklinville/Machias Fault, OC=Olean Creek Fault, Connois.=Connoisarauley Fault, S(E)=Seneca Lake E-striking Fault. Lineaments that are continuations of proposed faults probably mark extensions of the proposed faults. Rome Trough and related CSDs from Harper (1989). Earthquake magnitude symbols are the same as those in Figs. 1 and 4.

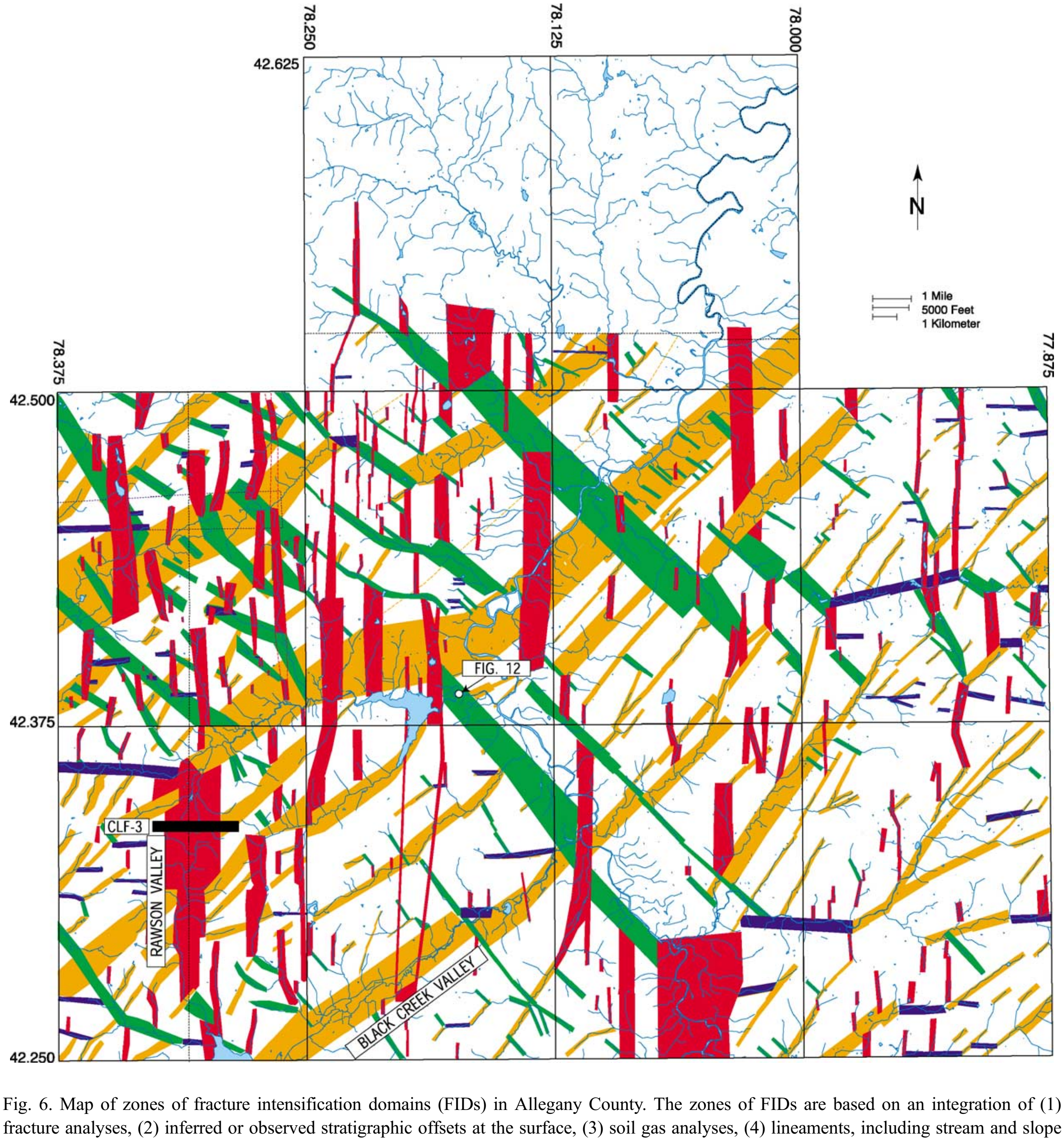


Fig. 6. Map of zones of fracture intensification domains (FIDs) in Allegany County. The zones of FIDs are based on an integration of (1) fracture analyses, (2) inferred or observed stratigraphic offsets at the surface, (3) soil gas analyses, (4) lineaments, including stream and slope lineaments on topographic maps, topographic and tonal lineaments on air photos and Landsat images, and tonal lineaments on SLAR and hyperspectral images, (5) faults inferred from well log analyses, and (6) faults observed on seismic reflection profiles (see Jacobi and Fountain, 2002, for details). Most larger FIDs indicate faults. The black bar labeled "CLF-3" indicates the location of seismic line shown in Fig. 7. For location of the map, see shaded box in Fig. 2. Map after Jacobi and Fountain (1996), Smith et al. (1998).

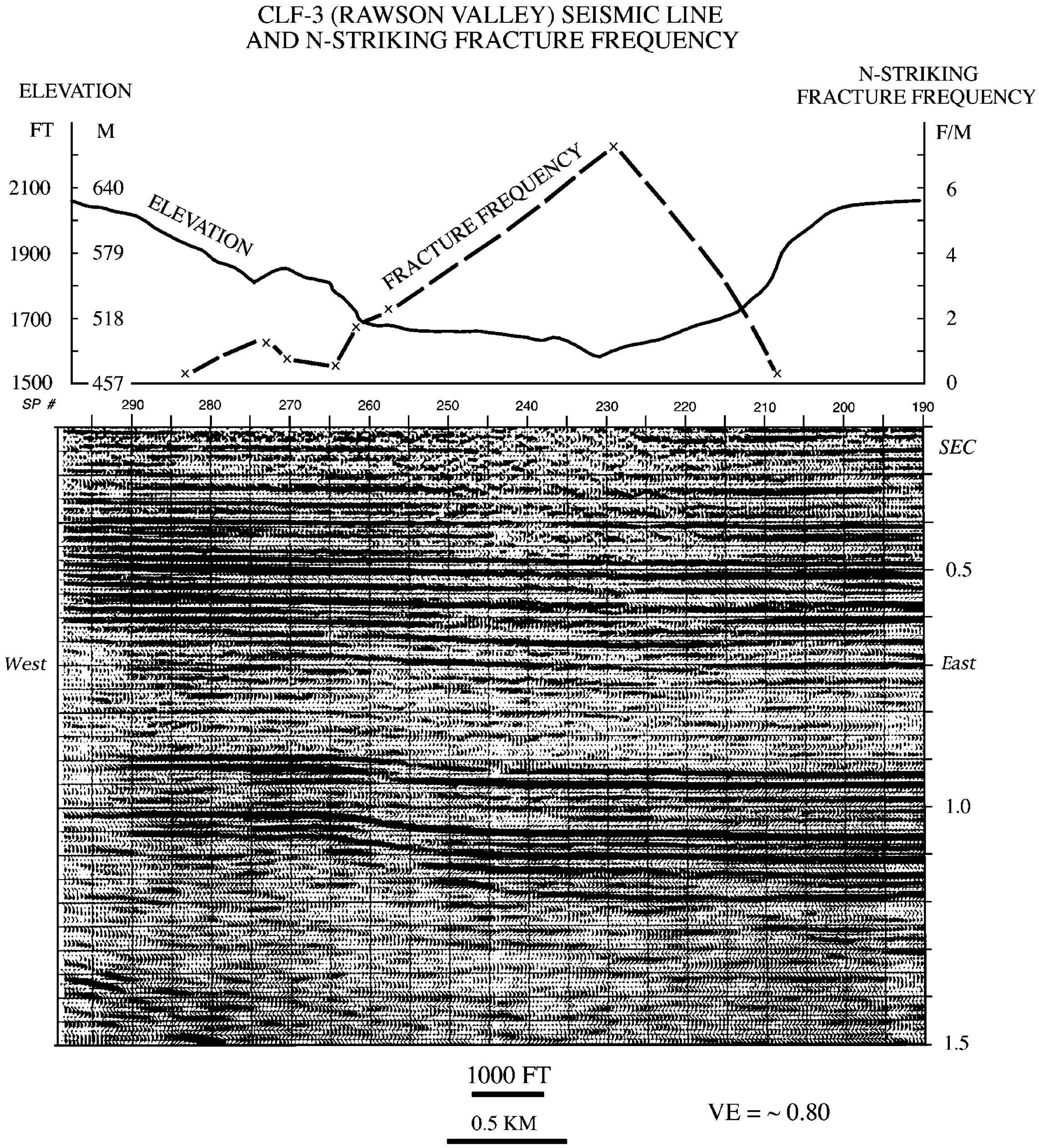


Fig. 7. Topographic profile, fracture frequency, and seismic section across the Rawson Valley Fault. This N-striking fault of the CLF is observed in the seismic section (lower image) at approximately shot point 255. The upper image shows that the fault at depth is coincident with a N-striking, prominent valley (Rawson Valley) and with a fracture intensification domain (FID) defined by closely spaced N-striking fractures (in units of fractures/m). F/M=fractures per m. Fig. 7 is located at #7 in Fig. 2 and at black bar annotated as "CLF-3" in Fig. 6. Modified from Jacobi and Xu (1998) and Jacobi and Fountain (2002).

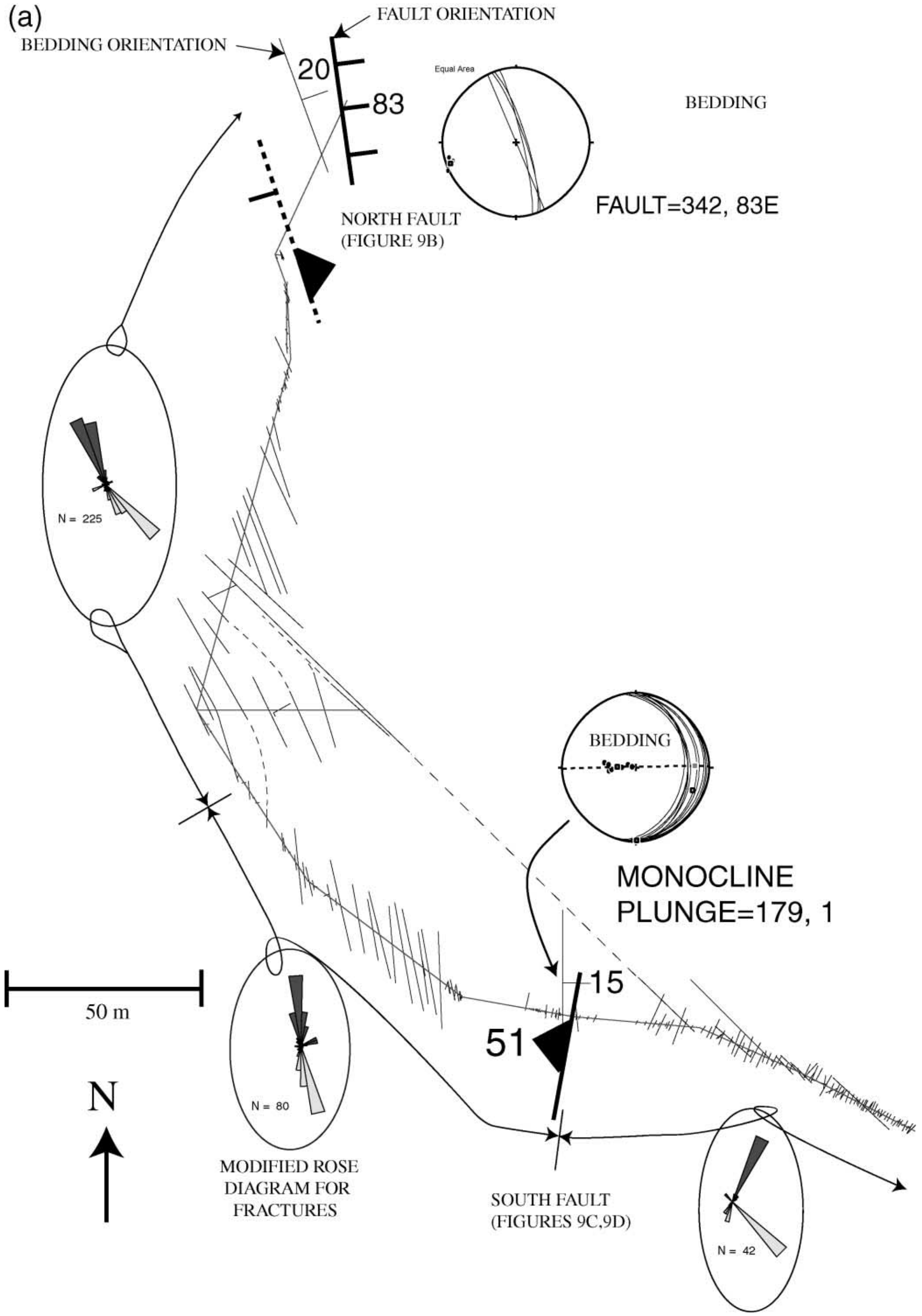
Fig. 8. Photograph of an approximately N-striking fracture intensification domain in the West Valley Fault System along Cattaraugus Creek. View is to the south. Note Brunton compass in lower left quadrant for scale. Outside this zone, the frequency of N-striking fractures is essentially 0/m (Fig. 8 is located at #8 in Fig. 2).

possible, given the sparse well coverage, and such a trend is consistent with the E97 lineaments and magnetic anomalies to the north (Figs. 2 and 4).

Approximately N-striking faults were also hypothesized for the north end of Keuka Lake (here named the Keuka Lake Fault, Fig. 5) on the basis of well log and field data (Bergin, 1964; Murphy, 1981; respectively). From structure contours Murphy (1981) inferred that Alleghanian (?) slip on the fault was down-on-the-west and dextral. These faults are probably associated with faults in the Precambrian basement because the Keuka Lake Fault coincides with a prominent gravity gradient (labeled "K" in Fig. 3) and a less prominent magnetic anomaly (Fig. 4b). The fault is also coincident with E97 lineaments (Figs. 2 and 5).

North-striking faults also have been recognized along Seneca Lake (here named the Seneca Lake N-Striking Fault System, Fig. 5). On the southeast side of Seneca Lake, N-striking Landsat lineaments identified by Isachsen and McKendree (1977) (see also Fig. 2) correspond to N-striking FIDs in outcrop (Lugert et al., 2001, 2002; Jacobi et al., 2002b) and stratigraphic displacements among widely spaced outcrops (Bradley et al., 1941). On the west side of Seneca Lake, NNW-striking lineaments correspond to a NNW-striking fault (Fig. 5) that was proposed on the basis of well log data and brine field fracture flow considerations (Jacoby and Dellwig, 1974; Murphy, 1981). Because the Seneca Lake N-Striking Fault System is not parallel to the primary gravity and magnetic gradients, the faults may not significantly affect Precambrian basement; rather, they may be primarily lateral ramps/tear faults related to Alleghanian thrusts. However, if the gravity low at the south end of Seneca Lake is not a function of incomplete gravity corrections, then the faults may affect more than the section above the Silurian salt.

In the Cayuga Lake region the N-striking, right-lateral Cayuga Lake Fault was inferred from well logs (Fig. 5; Murphy, 1981). In southernmost NYS, the



(a)
FAULT ORIENTATION
BEDDING ORIENTATION
20
83
Equal Area
BEDDING
FAULT=342, 83E
NORTH FAULT
(FIGURE 9B)
N = 225
BEDDING
MONOCLINE
PLUNGE=179, 1
15
50 m
51
N
N = 80
MODIFIED ROSE
DIAGRAM FOR
FRACTURES
SOUTH FAULT
(FIGURES 9C,9D)
N = 42

fault is coincident with a prominent topographic lineament (Murphy, 1981) and an E97 lineament (Figs. 2 and 5). The lack of coincident major gravity or magnetic anomalies suggests that the fault is primarily an Alleghanian tear fault with little basement control.

(b)

(c)

Fig. 9. North-striking faults along South Branch of Cattaraugus Creek (South Branch Fault in Fig. 5 and location #9 in Fig. 2). From Jacobi and Baudo (1999). (a) Map shows location of scanline (long continuous line) and fractures measured along the scanline. Modified rose diagrams in the ‘‘cameos’’ represent all fractures along the portion of the scanline indicated by the arrows linked to the cameos. Petals of the modified rose diagrams indicate fracture orientations, and petal lengths indicate relative fracture frequency (upper half) and relative fracture length (lower half). Longest fractures are the master fractures. Note that the N-striking fractures of the FID have a curving-parallel (abutting) relationship with the NW-striking master fracture, indicating that the FID postdates the NW-striking Alleghanian fracture. A prominent hydrocarbon seep is located at the base of the northern fault exposure. (b) Photograph of the North Fault, looking north. Long arrow points to the fault and the short arrow points to a 15-cm ruler. Note dipping units on the left in a fault horse (fault block caught up between the exposed fault and an assumed fault to the west). The units to the right of the fault are flat lying. (c) Photograph of a drag fold at South Fault (fault is out-of-view to the left; the view is to the south). Note the high dips at the lower left corner (indicated by white lines parallel to bedding). Scale is a 1.25-m (48 in.) horizontal ruler. (d) Photograph of the South Fault, looking north. Fault is located between the center arrow and the horizontal bedded units at the right under the tape reel. To the left (west) of the fault, note the high dips of units at the arrows along the water edge (white lines are colinear with diplines, whereas the adjacent black lines are horizontal). Scanline tape (1.3 cm wide) for scale.

(d)

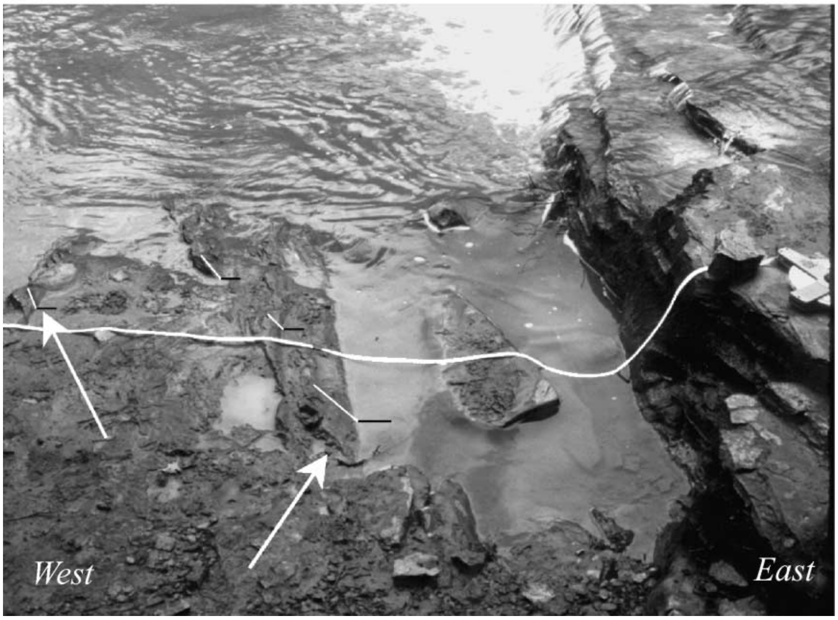


Fig. 9 (*continued*).

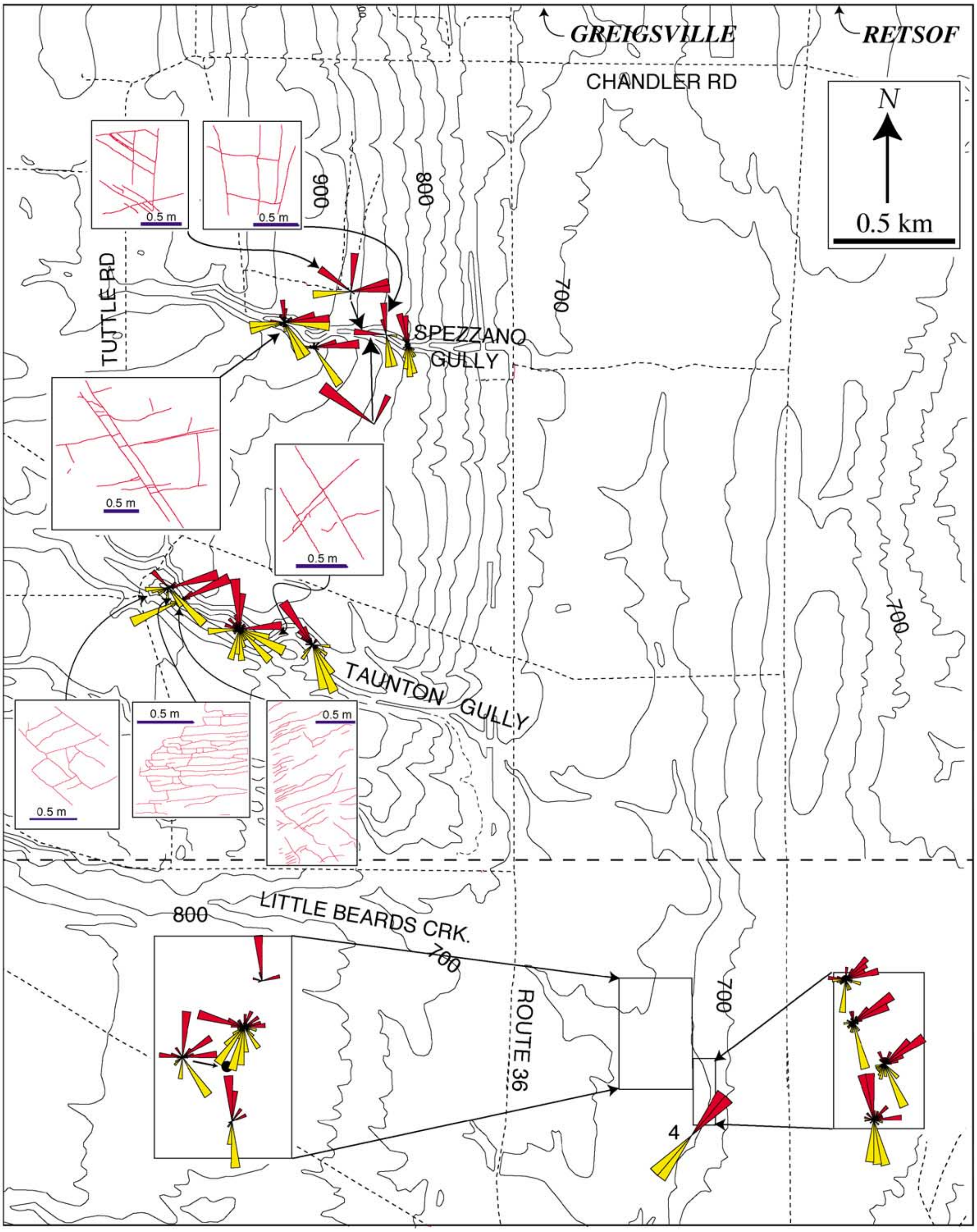
3.2. NE-striking faults

Based on growth-fault geometries inferred from sparse well logs, Rickard (1973) proposed an Ordovician N-striking horst and graben at the north end of Cayuga and Owasco lakes (Figs. 1 and 5; here called the Auburn Fault System). However, Saroff (1977) believed that the primary structural trend in the Auburn gas field is northeast, based on structure contours, magnetic lineaments, and the distribution of wells with interpreted high fracture porosity. Consistent with the proposed NE-striking faults of Saroff (1977) is a prominent magnetic high that trends northeast from Auburn to west of Oneida Lake ("A" in Fig. 4a, the "Auburn Fault Extension").

3.3. E- and ENE-striking faults

The only E- and ENE-striking faults that have been definitively proven in central NYS are the Glodes Corners Road faults and faults on the east side of Seneca Lake. The Glodes Corners Road faults were discovered in a recently recognized gas play west of Keuka Lake (Fig. 5), but the details are sketchy because of the proprietary nature of the data. The E- to ENE-striking fault zones are thought to have been active during Iapetan opening and Rome Trough development (Sanford, 2000), but the presumed easterly strikes of the Glodes Corners Road Field faults are not parallel to the east–northeast trend of the Rome Trough (Fig. 5). Furthermore, on-strike faults to the east cross the trend of the assumed main faults of the Rome Trough (Fig. 5). This conflict in orientation is unresolved, but indicates that the fault systems are probably more complicated than the generalized trends shown in Fig. 5. One alternative is that the E-striking faults may be en echelon short, shallower segments superimposed on older, deeper ENE- to NE-trending faults that parallel the assumed Rome Trough faults. Seismic reflection profiles in the Finger Lakes region show that the older faults are Eocambrian/Cambrian growth faults that offset the Precambrian/Cambrian contact (Jacobi et al., 2001b), but the actual fault trends are not definitive because the seismic reflection profiles are widely spaced. The E-striking faults higher in the section may represent Ordovician (Taconic) reactivations of the older faults. This younger, Ordovician age is based on (1) reflector offsets in seismic reflec-

(a)


GREIGSVILLE
RETSOF
CHANDLER RD
N
0.5 km
900
800
700
TUTTLE RD
SPEZZANO GULLY
0.5 m
TAUNTON GULLY
LITTLE BEARDS CRK.
800
700
ROUTE 36
4

(b)

(c)

Fig. 10. Map and photographs of structure in the Retsof area (location #10 in Fig. 2). (a) Topographic map displays the prominent N-striking topographic lineament, and the relationship to fracture orientations. Modified rose diagrams same as in Fig. 9. N-striking master fractures occur primarily in the N-striking valley and along the valley wall. The scangrids demonstrate the lack of N-striking fractures away from the valley floor and inner walls. Because the N-striking fractures are the master fracture, they are not thought to be valley effect fractures since they predate the Alleghanian NW-striking cross-strike fractures. (b) Photograph of N-striking fractures in limestones forming a N-striking FID. FID is located in the lower right box in Fig. 10a. Brunton for scale. (c) Photograph of a thrust ramp and flat in a duplex at site 4 in Fig. 10a.

tion profiles, and (2) offsets inferred from well logs. This age is consistent with the assumed age of dolomitization that was associated with fracture flow along the ‘‘open’’ faults (e.g., Sanford, 2000). Neither prominent E97 lineaments nor gravity and magnetic anomalies mark these E-striking faults. However, a prominent gravity low that strikes south from Lake Ontario decreases in magnitude the vicinity of the E-striking faults (G in Fig. 3). A further complication is that small (Alleghanian?) thrusts involving the Devonian units

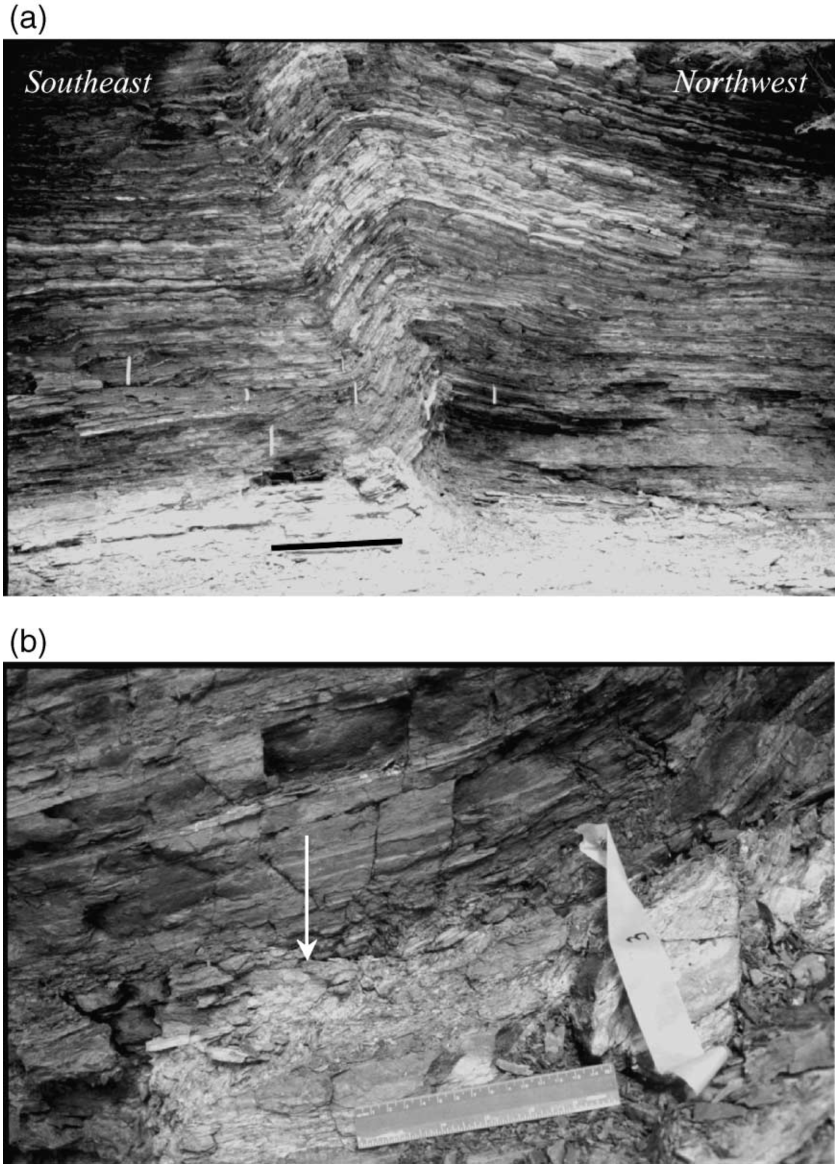


Fig. 11. Photograph of a NE-striking fold above a blind thrust along South Branch of Cattaraugus Creek. This fold strikes across the canyon, and so is not thought to be localized solely from erosive unloading in the canyon (i.e., it is not a local unloading-related pop-up). Black horizontal ruler 1.25 m (48) long in lower part of picture. View to the southwest (from Jacobi and Baudo, 1999) (locality #11 in Fig. 2). (b) Photograph of fault gouge and fault breccia on one of the faults in the fault/fold complex in Fig. 11a (locality #11 in Fig. 2). Scale is a 15-cm ruler.

(e.g., Tully and Oriskany formations) also strike roughly east–west (e.g., Wedel, 1932) and appear to be localized along the older structures.

East of Seneca Lake, E- to ENE-striking E97 lineaments (Figs. 2 and 5) coincide with faults and FIDs that affect Devonian bedrock (Bradley et al., 1941; Lugert et al., 2001, 2002; Jacobi et al., 2002b). Like the Glodes Corners Road faults, these E-striking faults probably were guided by older, deeper structures. No prominent gravity anomaly is associated

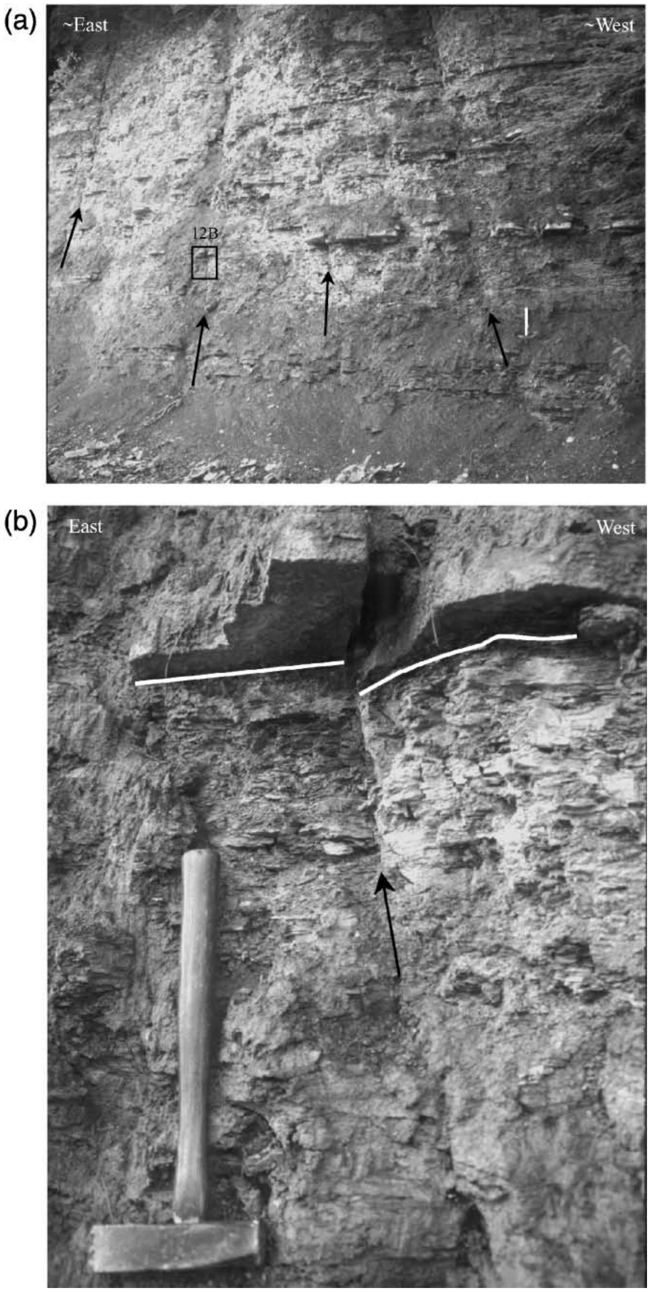


Fig. 12. (a) Photograph of four NW-striking step faults in Allegany County. These step faults experienced oblique slip, including down-to-the-southwest slip (visible in the photograph) and left-lateral slip, based on displaced ripple crestlines across other faults immediately to the west. Faults are located east of Rushford Lake along a major NW-striking CSD. View to the southeast. Hammer for scale. Location of figure shown as locality #12 in Fig. 2 and "Fig. 12" in Fig. 6. (b) Close-up view of a step fault (indicated by arrow). This fault is the second from right in Fig. 12a. Offset indicated by outlines on the base of a sandstone bed.

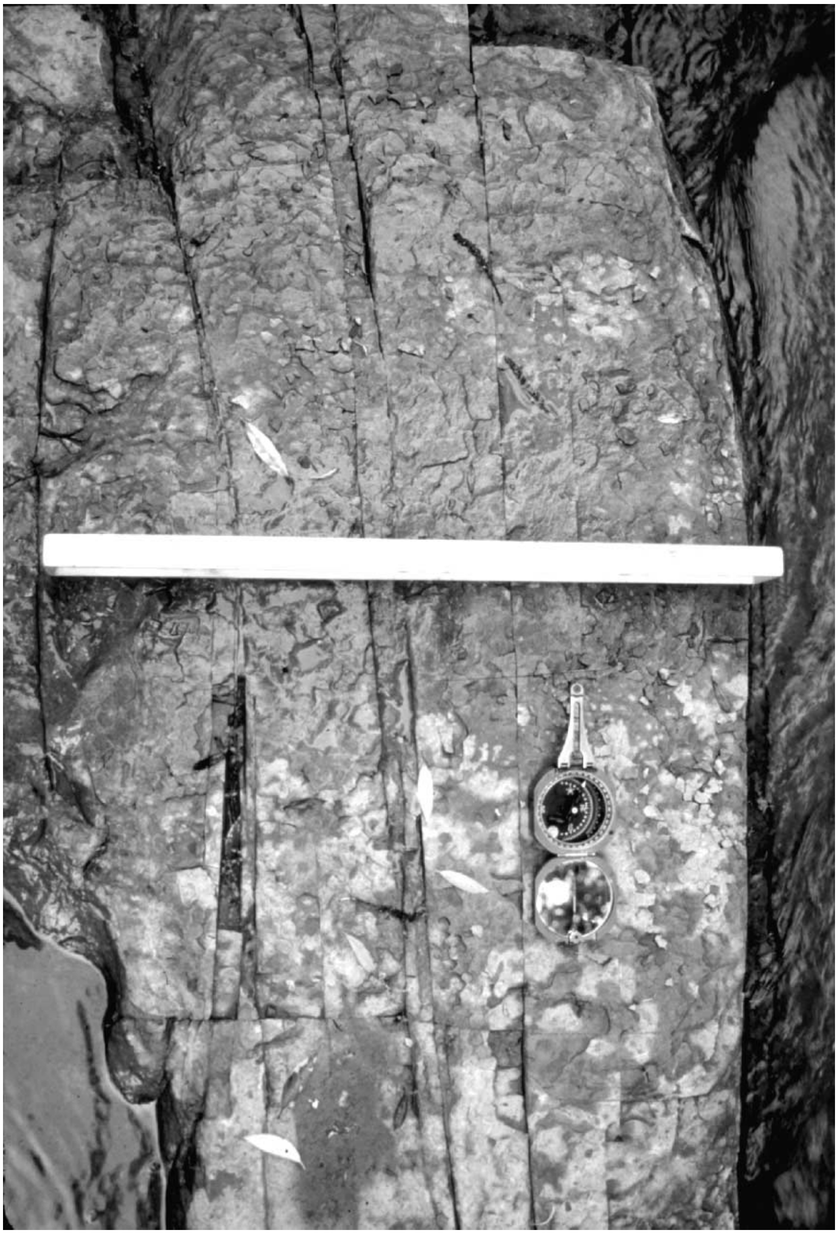
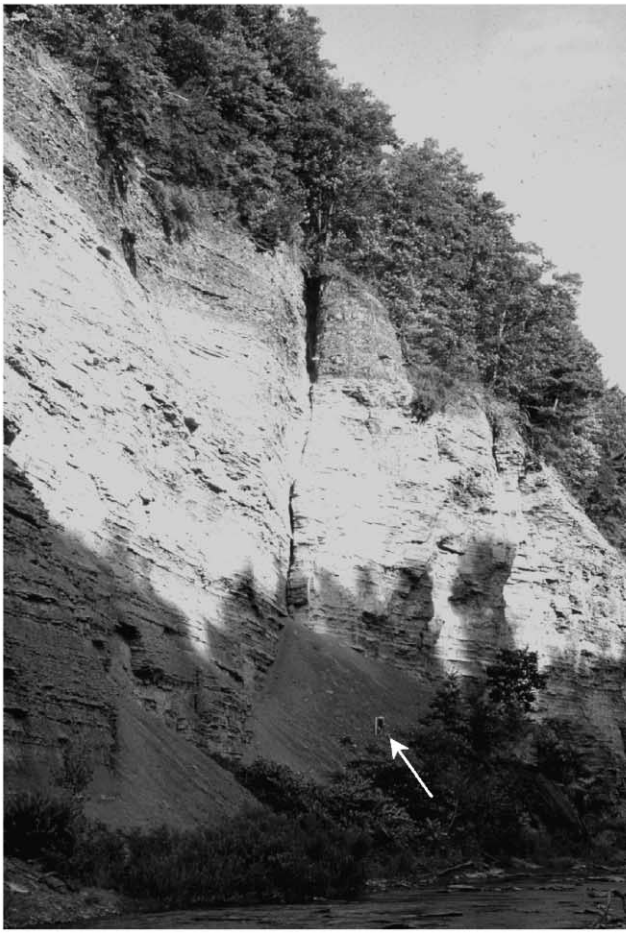


Fig. 13. Photograph of a NW-striking fracture intensification domain along Connoisarauley Creek. Scale is a 0.6-m (24 in.) ruler; view is looking down on the outcrop "pavement". Locality #13 in Fig. 2.

with the ENE-striking faults, although an ENE-striking magnetic anomaly crosses Seneca Lake in region of the faults. The E97 lineaments can be traced eastward into Delaware County.

Additional E- and ENE-striking faults are suspected in central NYS, based on E97 lineaments and coincident magnetic anomalies. These suspected faults include the Thruway, Schuyler County, and

(a)



(b)

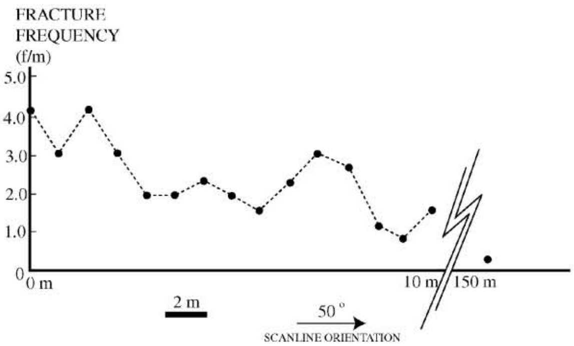


Fig. 14. Northwest-striking FID in South Branch of Cattaraugus Creek. Locality #14 on Fig. 2. (a) Photograph of a NW-striking FID that has a height greater than the canyon walls (arrow points to person for scale). The FID consists of 10+ closely spaced fractures in and adjacent to the weathered zone. (b) Frequency of NW-striking fractures along a scanline that crosses a NW-striking FID near the top of the canyon wall about 0.5 km south of the FID in (a). Outside the FID, the fracture frequency is about <1/m, as typified at 150 m, whereas the FID has a maximum of >4/m. Note that the boundary of the FID is gradational.

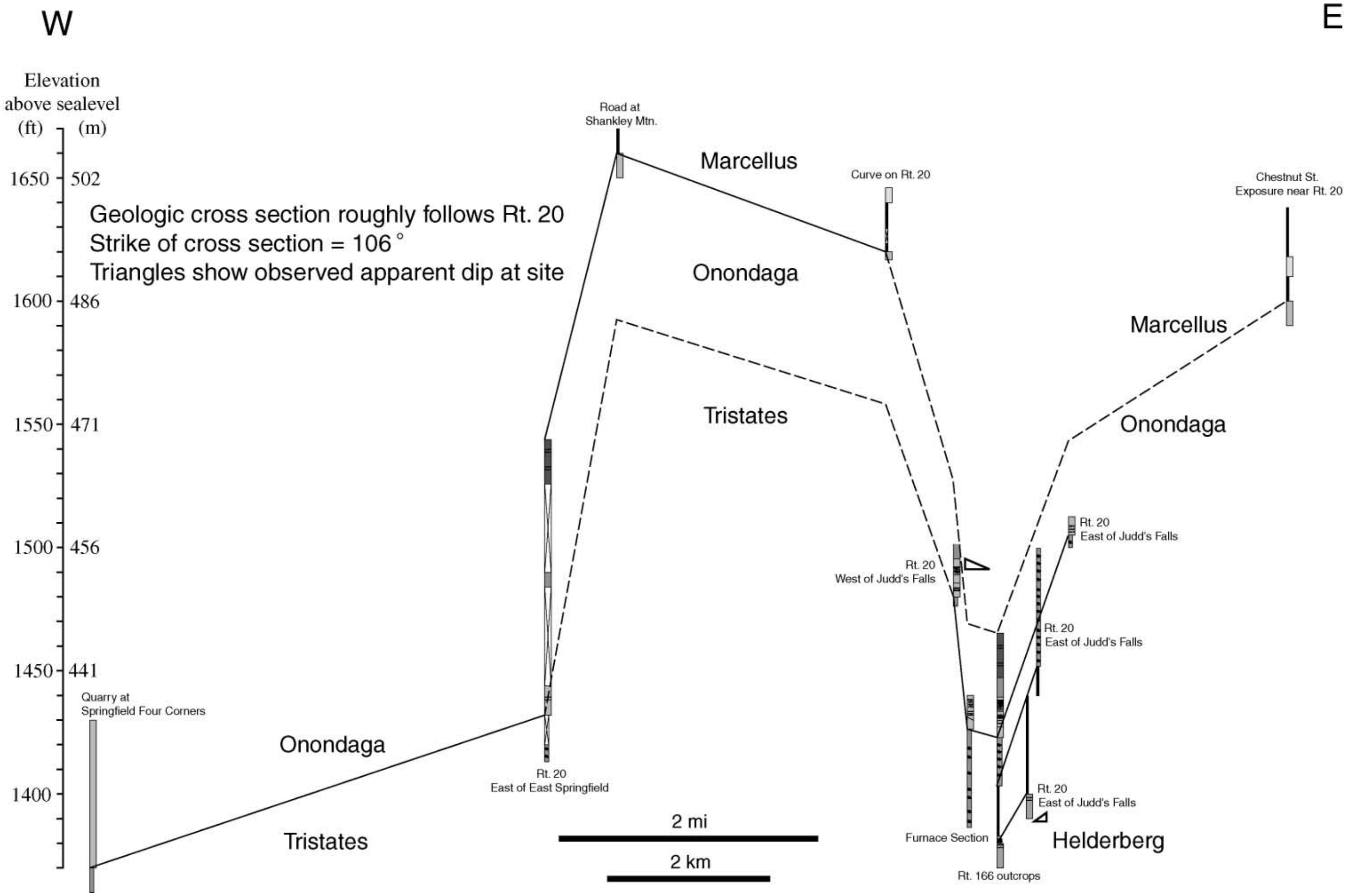


Fig. 15. Approximately east–west geological cross-section in Cherry Valley region (location #10 in Fig. 1). Locations of sharp elevation changes in the Devonian Onondaga Formation correspond to topographic and EARTHSAT (1997) lineaments that indicate both NNE-striking and NW-striking faults in this region. (after Jacobi and Smith, 2000).

Central NYS ENE-striking faults (discussed in Appendix A).

4. Eastern (Mohawk Valley) New York fault systems

The faults exposed in the Mohawk Valley (Figs. 1 and 5) have a long history of investigation (see Fisher, 1980; Bradley and Kidd, 1991; Jacobi and Mitchell, 2002 for reviews). These faults are thought to have formed horsts and grabens during the Taconic Orogeny as the Laurentian plate flexed during subduction and collision (e.g., Bradley and Kidd, 1991). Although the faults were assumed to have earlier histories as Iapetan opening (rift) faults, no evidence for such an origin has been reported (e.g., Bradley and Kidd, 1991). The faults were also assumed to have no post-Taconic motion (e.g., Fisher, 1980).

The faults generally have three orientations: NE, ~NS, and NW (Fig. 5). Northeast-striking faults, such as the Prospect and Mothers Creek faults (Figs. 1 and 5), and coincident E97 lineaments are parallel to the gravity low northwest of the Scranton Gravity High (Fig. 3). Because this gravity low marks the assumed trend of the Rome Trough and Iapetan rift faulting to the southwest (e.g., Figs. 3 and 5), the NE-striking Mohawk Valley faults were also probably active in the Cambrian/Eocambrian as Iapetan rift faults and Rome Trough development. Rickard (1973) extended some of the N-striking faults to the south by following coincident Landsat lineaments (Isachsen and McKendree, 1977). The ~N-striking faults, such as the Little Falls and Dolgeville faults, can be extended farther south along coincident E97 lineaments, where they cross the Rome Trough gravity low (Fig. 3). The disparity in trend between the N-striking faults and the NE-striking Rome Trough suggests that the N- and NE-striking fault systems may not share the same fault motion history. Although both fault systems were active during plate convergence in the Taconic Orogeny, as indicated by outcrop data in the Mohawk Valley (e.g., Bradley and Kidd, 1991; Jacobi and Mitchell, 2002), perhaps only the NE-striking faults have a significant older (Eocambrian/Cambrian) fault motion history, since they parallel the Iapetan rifts/Rome Trough. The proposed Taconic initial age of the N-striking faults is consistent with the lack of Iapetan rift facies associated with these faults at the Adirondack Dome (e.g., Bradley and Kidd, 1991).

Northwest-striking faults, such as the northeastern part of the variably trending Herkimer Fault, were rarely recognized in the region (e.g., Fisher, 1980; Bradley and Kidd, 1991). To the south in Otsego County, NW-trending magnetic anomalies, E97 lineaments, and topographic map lineaments are all coincident with NW-striking FIDs and faulted monoclines (Jacobi and Smith, 2000). The maximum age of the NW-striking faults is equivocal. Northwest-striking faults were active during the Taconic Orogeny, as evidenced by fault block rotations inferred from paleoslope changes and growth fault geometries along faults between the Herkimer Fault and the Dolgeville Fault (Jacobi and Mitchell, 2002). The NW-striking faults may also have an older history—they may be transfer zones between the Iapetan rift segments that stepped out to the east (present-day coordinates) around the New York recess (promontory) of Thomas (1977).

Evidence for post-Taconic motion along the Mohawk Valley faults is provided by the southward continuations of the Mohawk Valley faults. Jacobi and Smith (2000) have shown that the zero-lines for isopach maps of several Silurian units coincide with the southern extensions of the N- and NE-striking faults, suggesting Silurian fault-controlled deposition. Northeast- and NW-striking FIDs, faults, faulted monoclines, and coincident E97 lineaments that are on strike with the Mohawk Valley faults all occur in units as young as the Devonian (Fig. 15; e.g., Stevenson, 1948, 1949; Jacobi and Smith, 2000).

5. Relationship between seismicity and faults

5.1. Problems relating seismicity to specific faults

The inability to precisely locate seismic events introduces significant potential errors when attempting to relate specific seismic events to specific faults, and has prevented researchers from reaching a consensus on the location and source of seismic events in many parts of northeastern United States and Canada (e.g., Fakundiny and Pomeroy, 2002). The precision of both the epicenter locations and the depths of the

Table 1
Compilation of faults with spatially associated seismicity

Fault	Fault intersection	Fault name	Intersecting structures	Approximate orientation	County	Seismic event on Fig. 1	Selected fault reference
X		South Branch of Cattaraugus Creek Fault		NS	Erie/Cattaraugus	E1	this paper
	X		South Branch of Cattaraugus Creek Fault, NW lineament parallel to Folsomdale Fault	NS and NW	Erie/Cattaraugus	E1	this paper
X		West Valley Fault System (WVFS)		NS	Erie	E5 swarm	this paper
X		Franklinville – Five Mile Fault System (possible S extension of WVFS)		NS	Cattaraugus	Olean 1855 (Seeber+Armbruster '93)	this paper
	X		Franklinville – Five Mile Fault System with unnamed E-striking fault system	NS and EW	Cattaraugus	Olean 1855 (Seeber+Armbruster '93)	this paper
	X		West Valley Fault System, gravity gradient of Folsomdale Fault	NS and NW	Erie	northern 3 of E5 swarm	
X		Clarendon – Linden Fault System (CLF)		NS	Wyoming and Genesee	Attica swarm	Van Tyne (1975); Fakundiny et al. (1978); Jacobi and Fountain (2002)
X		Attica – Lockport and Folsomdale faults		NW	same as above	Attica swarm	same as above
	X		Clarendon – Linden Fault System (CLF), Attica – Lockport and Folsomdale faults	NS and NW	same as above	Attica swarm	same as above
	X		Clarendon – Linden Fault System (CLF), Lawrenceville – Attica Lineament	NS and NW	Wyoming	W2	same as above
X		southwest extension of the Attica Splay		NNE	Wyoming	W1	same as above
X		Leroy Fault (northward extension)		NS	Monroe	M1	Rickard (1973)
X		Thruway Fault		EW	Ontario	OT1, OT2	this paper
	X		Thruway and Retsof faults	EW and NS	Genesee	G/M	this paper
	X		N-striking and Thruway magnetic anomalies, ENE-striking E97 lineaments	EW, NS	Ontario	OT5	this paper
X		Hemlock Fault		NNW	Livingston	L1	this paper
X		Lawrenceville – Attica Lineament System		NW	Livingston	L2, possibly ST2, ST3	this paper
X		Canandaigua Fault		NS	Ontario	OT3, OT4	Rickard (1973)
X		Keuka Lake Fault, southern extension		NNE	Steuben	ST3	this paper; Murphy (1981)
	X		Keuka Lake Fault, Lawrenceville – Attica, Lineament System	NNE and NW	Steuben	ST3	this paper; Murphy (1981)

	X		Glodes Corners Road faults, unnamed fault parallel to Keuka Lake Fault, Cuba Fault extension	EW, NNE, NE	Steuben	ST1	this paper
X		Auburn Fault		N? NE	Cayuga	CA1	Rickard (1973) Saroff (1977)
X		Owasco Fault (extension of Auburn?)		NNW		CA2	this paper
	X		magnetic anomaly (NE), E97 Otisco lineaments (NNW), E97 lineaments (ENE)	NE, NNW, ENE	Onondaga	ON1	
X		Oswego Trend Onondaga Fault (SSE extension of Oswego?)		NNW NNW	Oswego Onondaga	OS1, OS2, OS3 ON2, ON3	McFall (1993) this paper
	X		Onondaga Fault, Auburn NNE Extension	NW and NNE	Oswego	OS1	this paper
	X		Onondaga Fault extension, magnetic anomaly	NNW and NNE	Oswego	OS2	this paper
X		Prospect Fault		NE	Oneida	ONE1	Bradley and Kidd (1991)
X		(an unnamed gravity gradient)		NW	Oneida	ONE2	this paper
	X		Prospect Fault, unnamed NW fault	NE and NW	Oneida	ONE1	this paper
X		Utica East (extension of Rome Trough), possibly extension of Buttermilk Creek+City Brook faults		NE	Oneida	ONE3	this paper; Bradley and Kidd (1991)
X		Herkimer Fault		NE	Herkimer	H1	Bradley and Kidd (1991)
	X		Little Falls Fault, unnamed cross faults	NE and NW	Herkimer	H2	Bradley and Kidd (1991)
X		Ephrata and West Stone Arabia faults		NE	Montgomery	M1	Bradley and Kidd (1991)
	X		Ephrata and West Stone Arabia faults, possible gravity cross trend	NE and NW	Mongomery	M1	
X		Sprakers Fault, southern extension		NS	Delaware	D1, D2	this paper
X		Susquehanna River/Scranton Gravity High faults		NE	Otsego	OTS1-3	this paper
	X		Susquehanna River/Scranton Gravity High faults, possible magnetic cross trend or Sprakers Fault	NE and NW	Otsego	OTS1-3	this paper
X		fault of the St. Lawrence Rift fault system		NE	Jefferson	J1-3	this paper
X		Carthage – Colten Mylonite Zone (?)		NE	Lewis	LW1	e.g., Mezger et al. (1992)

seismic events have generally been poor in western NYS and Ontario because of an inadequate number of seismograph stations (e.g., Mohajer, 1993). For example, the best precision for epicentral locations was estimated to be ±10 km for 1991 seismic events in the western Lake Ontario/eastern Lake Erie region of Ontario, where five seismic stations were operating (Mereu, personal communication, 2002). In contrast, at present, no regularly networked seismographs operate in western NYS (although seismograph stations did operate at Attica and elsewhere in western NYS in the past; Fletcher and Sykes, 1977; Sbar and Sykes, 1977). Thus, the ability to discriminate the source fault among closely spaced faults is hindered by the lack of epicentral precision.

The depth of the seismic events is also generally unknown for NYS seismic events. If the faults are steeply dipping, then the unknown hypocentral depth is not a major factor in relating the epicenter to the surface trace of a particular fault or fault system. However, if the source fault is gently dipping, then the depth of the seismic event becomes critical, because the fault trace at the surface will be significantly displaced from the epicenter if a deep segment of the fault was the source of the seismic event. The result will be that epicenters away from the surface trace of the fault will be incorrectly regarded as unrelated to the surface fault trace. Because the CLF faults in the Precambrian basement probably dip moderately to the east, the depth of the seismic events is an important consideration.

The only seismic events that have calculated hypocenters for the study area in the Appalachian Basin of NYS are those along the CLF. Fletcher and Sykes (1977) determined that the depth of induced seismicity (resulting from a high-pressure injection near Dale) ranged from 0.5 to 1.0 km. These shallow values are within the Paleozoic section. Two natural seismic events along the CLF near Attica have calculated depths of 2 and 3 km (Hashizume and Tange, 1977; Hermann, 1978), near the top of the Precambrian basement. If these depths are typical for other seismic events near Attica, then the dipping faults in the Precambrian are not a major concern for comparing the epicenter locations with fault traces at the surface. Indeed, the shallow hypocenters are consistent with the close correspondence between seismic events at Attica and the basement indicators of the CLF, including magnetic and gravity gradients (Figs. 3 and 4), and faults observed in seismic reflection profiles (e.g., Fakundiny et al., 1978; Fakundiny and Pomeroy, 2002; Ouassaa and Forsyth, 2002). It may be that the small magnitude seismic events prevalent in NYS generally have shallow depths (Sbar and Sykes, 1977).

In nearby regions outside the study area, several studies have shown a range of hypocenter depths. To the east, Quittmeyer et al. (1982) found that microearthquakes south–southwest of Albany (NY) had a depth of about 17–19 km. Depth ranges for seismic events in the western Lake Ontario/Province of Ontario region range from 1 to 19 km deep (Mohajer, 1993; Mereu, personal communication, 2002). Similarly, Ebel and Kafka (1991) found that the depths of seismic events in northeastern USA range from about 2 to 20 km, with a mode at 9 km and a standard deviation of 5 km. If the deeper seismic events also occur in the study area, then the proposed correlations between seismic events and faults in NYS should be approached with caution. However, either most of the seismic events in the study area are relatively shallow, and/or the particular faults are steeply dipping, because most of the epicenters in the study area are located along prominent gravity and magnetic gradients. Thus, the correspondence proposed below between seismic events and particular faults may be more robust than one might expect.

5.2. Seismicity and faults in the study area

The compilation of faults that are spatially associated with seismic events (Table 1) suggests that recorded seismic events have occurred along 23 fault traces and/or at 16 fault intersections. Because of the low spatial precision for epicenters, as well as the large number of fault intersections, the assignment of particular seismic events to particular faults or fault intersections is nonunique for some of the seismic events. The most equivocal seismic event sources are not included in Table 1; rather, they are discussed below. Assuming that the faults and fault intersections suggested in Table 1 were the sources of the seismic events, all but one of the seismically active faults in western and central NYS strike north or northwest. The strikes of the seismically active faults are kinematically consistent with the ENE-strike of the present maximum principal compressive stress (e.g., Zoback and Zoback, 1991). The most prominent of the western NYS fault sources is the CLF, which is discussed briefly below. In eastern NYS, several of the NE-striking "Mohawk Valley faults" (e.g., Prospect Fault, Fig. 5) appear to be seismically active near the uplifting Adirondack Dome. Northwest-striking cross trends may have facilitated motion on these faults, or may be the actual faults slipping in the present stress field at intersections with the NE-striking faults. A N-striking Mohawk Valley fault, the Sprakers Fault (Fig. 5), is also seismically active.

There is little question that the CLF is seismically active (for a review, see Jacobi and Fountain, 1993, 1996, 2002). Focal mechanism studies suggest a northerly striking fault with reverse and right-lateral motion (Fletcher and Sykes, 1977; Hermann, 1978). Seismic events superimposed on the gravity map show that a seismicity swarm is located along the western flank of the gravity high associated with the CLF (Fig. 3). The northern termination of the seismicity swarm occurs where the gravity high diminishes in amplitude. The seismicity swarm also extends northwest from Attica along the NW-striking gravity high bordered by the Attica–Lockport and Folsomdale faults. It appears that the seismicity is localized not only by the intersection of two major trends but is also marked by the relatively high gravity anomalies (Fig. 3; Jacobi and Fountain, 1996). Based on seismic event W1 (Fig. 1), the southwest extension of the Attica Splay Fault of the CLF (Fig. 5) is also seismically active.

In Niagara County and offshore Lake Ontario, the epicenters of five seismic events align along the Wilson–Port Hope Lineament (seismic events WPHL5 in Fig. 1; e.g., Mohajer, 1993). The on-land seismic events in WPHL5 (Fig. 1) could also be related to the NW-striking Georgian Bay Linear Zone (GBLZ; Wallach, 1990; Fig. 5), or to an intersection of the GBLZ with ENE-striking faults of the Lake Ontario zone (Fig. 5, see Appendix A for discussion of the Lake Ontario zone). A similar nonunique association occurs in eastern Niagara and central Orleans counties where seismic events N1 and OR2 all could be related to faults of the ENE-striking Lake Ontario zone, or to the GBLZ and a northern extension of the West Valley Fault System, respectively (Fig. 5).

The epicenters of the three seismic events (OTS3) in easternmost Otsego County (Fig. 1) are located on the NE-trending E97 lineament and gravity gradient that mark the Susquehanna River/Scranton Gravity High faults (Fig. 3). However, these epicenters are located within 10 km of the N-striking Sprakers Fault, suggesting that this fault, or an intersection of this fault and the Susquehanna River/Scranton Gravity High faults, could also be the source. Similarly, two seismic events in Delaware County (Fig. 1) could be related to a southern extension of Sprakers Fault, the Scranton Gravity High faults, or the intersection of these two trends (Figs. 3 and 5).

The three seismic events (labeled "J3" in Fig. 1) in the central part of Jefferson County may be related to a possible NE-striking fault that strikes parallel to the St. Lawrence Rift fault system (e.g., Adams and Basham, 1989) (Fig. 5). The tight NE-striking alignment of these seismic events with several more events to the northeast might suggest a border fault of the St. Lawrence Rift fault system (Fig. 5).

6. Discussion and conclusions

This paper demonstrates that many of the EARTHSAT (1997) lineament bundles can be correlated spatially both with FIDs at the surface and faults either at the surface or at depth. Many of these fault systems are rooted in the Precambrian basement, where the "carrier" of the present plate stress is assumed to reside. Thus, it is not surprising that almost all of the seismic events in the Appalachian Basin portion of NYS can be correlated with the known and suspected faults. It appears that more faults are seismically active in NYS than previously supposed. It may be that most of the basement faults that extend to the surface rocks are seismically capable, even those that do not have historical seismicity ascribed to them. Further work will undoubtedly modify the specific locations of fault traces and their seismic capability. However, the conclusion is inescapable that a large number of faults do exist in NYS, and that several of them have been seismically active.

An important observation is that these seismically active faults crisscross a large portion of NYS. The high number of faults means that most cultural facilities (e.g., waste disposal sites, bridges, pipelines) are not far from a potentially seismically active fault. For example, the West Valley faults extend south to the West Valley Demonstration Project, a high- and low-level radioactive waste storage site. Similarly, the Attica–Lockport Fault passes fairly close to the Darien Lakes theme park, where some of the highest amusement rides in the Northeast are located. And one final example: in the Mohawk Valley region, the south end of the Hinckley Reservoir dam is adjacent to the Prospect Fault. Thus, it is vitally important to assess the maximum credible seismic event that can be expected along these faults.

The maximum credible seismic event is extremely difficult to determine, partly because the historical recurrence rates of all earthquake magnitudes are relatively low in NYS (especially the moderate magnitude events) and because there may be a disconnect on Gutenberg–Richter curves between small events and maximum credible seismic events. Paleoseismology should be an important tool in evaluating the seismic capability and maximum credible seismic event. However, the only fault in the NYS Appalachian Basin that has received even limited attention (outside of the St. Lawrence region) is the CLF (Tuttle et al., 1996). As discussed in Jacobi and Fountain (1996, 2002), Tuttle et al. (1996) did not find unequivocal evidence for liquefaction along the CLF, implying no unequivocal $M>6$ along the CLF in post-glacial times. This conclusion is consistent with the discovery that the CLF appears to consist of short fault segments broken by CSDs (e.g., Jacobi and Fountain, 1996). Johnston et al. (1994) employed a different approach by combining all the intracontinental fault systems that are located on extended crust; a sufficient number of seismic events can then be obtained to better estimate the maximum credible earthquake. Using this approach, the maximum credible earthquake for the CLF has a range between $M=5.5$ and $M=7.5$, with the mode at about 6.5 (Geomatrix Consultants, 1997; Jacobi et al., 1997). The dichotomy in results between the liquefaction approach and the Johnston et al. (1994) approach can be resolved in two ways: either the "worldwide" estimate applied to the CLF is incorrect because the short segments of the CLF do not allow a large stress build-up and release, or the liquefaction study is not definitive. The present data sets are not adequate to determine which of these alternatives is correct.

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Appendix A. Suspected faults

A.1. N-striking suspected faults in western New York

In Chautauqua County, N-striking lineaments observed in topography northeast of Chautauqua Lake are coincident with an EARTHSAT (Earth Satellite Corporation) (1997) lineament (the Charlotte Center Fault, Fig. 5). A coincident aeromagnetic low (labeled "CC" in Fig. 4a) suggests that the suspected fault involves Precambrian basement. This fault and associated magnetic low are on strike with delineation of the eastern border of the Central Metasedimentary Belt Boundary Zone (CMBBZ) of Eyles et al. (1993) and Hutchinson et al. (1993) (Fig. 5). It is probable that motion on the fault influenced Silurian salt deposition because the zero-line of Silurian salt isopach map departs from the NE-striking Bass Island Trend and follows the N-striking lineaments (Fig. 5). In order to tectonically control the western edge of the salt basin, the fault would have had to experience down-on-the-east motion during Silurian salt deposition. North-striking magnetic and gravity anomalies in westernmost Chautauqua County suggest that another N-striking fault may exist west of the Charlotte Center Fault.

In Cattaraugus County, topographic lineaments and E97 lineaments that lie in the N-striking gravity low suggest N-striking fault systems. For example, the 20+ km N-striking valleys at Franklinville and Machias, the 15-km-long Five Mile/Four Mile valley, the 12-km-long Olean Creek valley, and the 13-km-long Allegheny River/Tuna Creek Valley (FM, FF, OC, and ART in Fig. 5) may form a series of segmented N-striking faults that are connected by transfer zones. The suspected fault in the Olean Creek valley may be related to the CLF Rawson Fault, and the western valleys may indicate southern extensions of the West Valley Fault System.

A.2. NE-striking suspected faults in western New York

Several NE-striking fault systems are proposed on the basis of E97 lineaments, some of which are coincident with geophysical anomalies. In Chautauqua County, the Mayville Fault (Fig. 5) is based on a NE-striking E97 lineament bundle that is coincident with the northwesternmost extent of the zero-line of the Silurian salt isopach in Chautauqua, Cattaraugus, and Erie counties (Figs. 2 and 5). Alleghanian thrust ramps, similar to those of the Bass Island Trend, probably occur along the salt zero line. North-striking magnetic anomalies are truncated where the Mayville Fault lineament bundle (labeled "M" in Fig. 4b) crosses the anomalies. Northwest of the E97 lineament bundle the magnetic anomalies have a distinct NE-trend (Fig. 4b). The NE-striking magnetic gradient continues southwest into Pennsylvania (Fig. 4) and the northeastern extent of the fault, although equivocal, may be the Attica Splay Fault (Fig. 5), based on the zero-line of the salt isopach and changes in magnitude of N-striking magnetic anomalies where the zero-line crosses the anomalies. The associated magnetic anomalies and their trend suggest that the Mayville Fault may have been an Iapetan rift fault initially; the coincident salt zero-line suggests that the fault controlled Silurian salt deposition and marks Alleghanian thrust ramps.

In Allegany and Steuben counties, NE-striking faults (Boliver Fault System) are based on NE-striking E97 lineaments (Figs. 2 and 5). Wedel (1932) proposed Alleghanian NE-trending folds in the same general area, based on level lines along bedding surfaces. Bradley et al. (1941) proposed several folds and faults on the basis of well logs and outcrops. North of the Boliver Fault in Allegany County (area 6, Fig. 1; Jacobi and Fountain, 1993, 1996) and in Livingston County (Fig. 10a and b), lineaments, FIDs, thrusts, and surface stratigraphic offset are consistent with NE-striking Alleghanian faults. Those faults that do not have significant magnetic anomalies associated with them are probably thrust ramps restricted to units above the Silurian salt.

Both north and south of the Boliver Fault, several other northeast-trending lineaments arc through western New York. The portions of these lineaments that do not follow prominent gravity and magnetic anomalies probably mark Alleghanian faults that are restricted to the stratigraphic section above the Silurian salt, where the Alleghanian decollement resides (e.g., Prucha, 1968). For example, immediately east of area #10 (Fig. 2), prominent NE-trending topographic lineaments and E97 lineaments (Fig. 2) cross several N-trending magnetic lineaments (Fig. 4b). However, in other localities, the NE-striking lineaments do correspond to aeromagnetic gradients, and suggest that in several areas, the Alleghanian faults lie above deeper faults that affect Precambrian basement (e.g., south of the Boliver Fault in easternmost Allegany County, Fig. 4b).

In Niagara County, ENE-striking faults (here named Lake Ontario Zone, Fig. 5) are proposed on the basis of lineaments (Fig. 2) and FID exposures along the lakeshore and in creeks south of Lake Ontario (Harper and Jacobi, 2000). The master fractures associated with this trend do not appear to arc across NYS, unlike the Alleghanian strike-parallel fractures (e.g., Engelder and Geiser, 1980). Some of the ENE-striking FIDs are master to the NW-striking cross-strike fractures of assumed Alleghanian age, suggesting the ENE-striking FIDs are older than Alleghanian and possibly result from reactivation of Iapetan (?) failed rift faults. Other ENE-striking FIDs abut the NW-striking cross-strike fractures, and these FIDs may represent Jurassic/Cretaceous rift faults (Harper and Jacobi, 2000), consistent with earlier proposals based on Lake Ontario geomorphology (Thomas et al., 1993). The lack of prominent magnetic or gravity anomalies associated with these lineaments suggest that if the faults do exist, they affect the Precambrian basement in a minor manner.

A.3. NW-striking suspected faults in western New York

Suspected NW-striking faults are proposed for topographic and E97 lineaments in Chautauqua County and along the Lawrenceville–Attica lineament (Figs. 2 and 5). In Chautauqua County, the most notable lineament is Chautauqua Lake itself (Figs. 1 and 2). That the lineaments in Chautauqua County extend northwest of the Bass Island Trend and the proposed NE-striking Mayville Fault (Figs. 2 and 5) suggests either that the northwestern limit of Alleghanian thrust faulting in NYS is not marked by the Bass Island Trend and the Mayville Fault, or that the NW-trending lineaments are related to deeper structures as well as to lateral ramps of the thrusts. Support for the latter hypothesis, faults in Precambrian basement, is provided by the southwesternmost NW-striking FID that follows a NW-striking magnetic gradient (labeled "CH" in Fig. 4b). In Pennsylvania NW-striking faults (CSDs) were also thought to mark deeper faults that controlled the location of shallower tear faults (e.g., Kowalik and Gold, 1976; Shumaker and Wilson, 1996; Gold, 1999).

Two parallel faults, the Attica–Lockport and Folsomdale faults (Fig. 5), are proposed on the basis of coincident features including: (1) NW-striking valleys, (2) E97 lineaments (Fig. 2), and (3) a NW-striking gravity high (labeled "A" in Fig. 3), and (4) an aeromagnetic high (Fig. 4; Jacobi and Fountain, 1996). The Attica–Lockport Fault is located along the northeast flank of the gravity high, and the Folsomdale Fault along the southwest flank. Both the E97 lineaments and gravity gradients are truncated by lineaments of the West Valley Fault System (Figs. 3 and 5), although Wallach (1990) suggested that the NW-striking magnetic high was a southeastward continuation of the Georgian Bay Linear Zone (GBLZ in Fig. 5). The lack of magnetic data in Niagara County and the truncated gravity anomaly hinders a definitive determination of the northwest extensions of both faults, but a possible northwest continuation of the Attica–Lockport Fault along minor E97 lineaments meets the southwest margin of the Georgian Bay Linear Zone (GBLZ) as portrayed by Wallach (1990; Fig. 5). This en echelon nature between the GBLZ and the zone defined by the Attica–Lockport and Folsomdale faults may be an artifact of definitions, since the southwest boundary of the GBLZ as portrayed by Wallach et al. (1998) is on strike with the Folsomdale fault. The southwest extension of the Folsomdale Fault is the Lawrenceville–Attica Lineament (discussed below, Fig. 5).

The magnitude of the geophysical anomalies between the Attica–Lockport and Folsomdale faults indicates a mafic body, and the steep gradients suggest that the mafic body is relatively shallow—perhaps near the top of the Precambrian basement. The age of the proposed igneous mafic complex and faults is equivocal. Barosh (1990) suggested that the NW-striking CSDs formed in response to the present Atlantic opening tectonics. However, well log analyses by Pearce (1991) suggest that these faults were active in the Silurian. Aditionally, seismic reflection data and well control across NW-striking CSDs in Pennsylvania and Ohio show that several NW-striking CSDs have long Phanerozoic reactivation histories and may be originally Precambrian-aged faults (e.g., Harper, 1989; see discussion in Jacobi and Fountain, 2002).

The Lawrenceville–Attica Lineament strikes northwest from northern Pennsylvania to Attica (Fig. 5; Diment et al., 1980; Harper and Laughrey, 1987) and continues northwest (Parrish and Lavin, 1982) as the proposed Attica–Lockport and Folsomdale faults (Fig. 5). The Lawrenceville–Attica Lineament was proposed on the basis of terminations of NE-striking gravity anomalies located northwest of the Scranton Gravity High (Fig. 3); the Lawrenceville–Attica Lineament itself appears to terminate against the Scranton Gravity High (Fig. 3). Well logs show that the Devonian Onondaga Formation gradually drops down to the southwest at least 150 m across the lineament; the well spacing does not allow discrimination between a NW-striking monocline and a series of NW-striking faults. Parrish and Lavin (1982) suggested that the prominent circular gravity high on the Lawrenceville–Attica Lineament at the southern border of NYS is the result of a kimberlite intrusion that was localized by the intersection of the CSD and the orthogonal Rome Trough (Fig. 3).

A.4. Suspected northerly striking faults in central New York

Lineaments associated with Murphy's (1981) Keuka Lake Fault extend north–northeast to Lake

Ontario (named here the Keuka Lake Fault Extension; Figs. 2 and 5). Like the Keuka Lake Fault, the suspected northeast extension also follows a gravity gradient south of Lake Ontario (K′ in Fig. 3). The Keuka Lake Fault Extension tracks the western margin of the Romulus Trough (or sag), a Middle Devonian local depositional basin (e.g., Mayer et al., 1994), and is the locus of facies changes in Middle Devonian units (Mayer et al., 1994). It thus appears that this fault was a control for Middle Devonian basinal deposition. A splay of the Keuka Lake Fault trends south–southwest along a prominent E97 lineament and magnetic lineament which extends south to the NYS border (KS in Fig. 4b). The magnetic gradient suggests that the Keuka Lake Fault affects Precambrian basement.

To the east, the Tioga County Fault (Fig. 5) is suspected on the basis of long, NNW-striking E97 lineaments (Fig. 2). These lineaments are parallel the southern part of the Cayuga Lake Fault of Murphy (1981, Fig. 5). The lack of coincident geophysical anomalies is consistent with Murphy's (1981) suggestion that the Cayuga Lake Fault is an Alleghanian tear fault that does not extend below the Silurian salt section.

A.5. Suspected E- and ENE-striking faults in central New York

Three suspected E- and ENE-striking fault systems are located in central NYS: the Thruway Fault, the Schuyler County Fault, and the Central NYS ENE-striking faults. The Thruway Fault (Fig. 5) is defined by a prominent E-striking magnetic anomaly (labeled "T" in Fig. 4b) and coincident E97 lineaments. Although the zero line of the Silurian salt isopach approximately follows the magnetic anomaly, the present zero-line in that region is a function of the Salina Group outcrop belt. Nevertheless, the salt section thickens rapidly immediately south of the present outcrop/zero-line (Kreidler, 1957), suggesting that the northern limit of the Silurian salt basin was fault-controlled by structures in the Precambrian basement associated with the Thruway Fault.

The Schuyler County Fault is suspected on the basis of E97 lineaments and coincident magnetic anomalies (labeled "Schuyler Cnty" in Fig. 5). The trend, magnetic signature, and proximity to the Glodes Corners Road faults suggest that this fault (and the Seneca Lake E-striking Fault, Fig. 5) may have a long reactivation history like the Glodes Corners Road faults: Iapetan rifting, Taconic motion, possible Acadian motion, and guide for Alleghanian thrust development. Indeed, these lineaments approximately track the Alleghanian surficial Firtree Anticline and associated syncline of Wedel (1932).

Numerous ENE-striking lineament bundles that cross central NYS suggest the Central NYS ENE-striking faults (Figs. 2 and 5). Several of these faults are generally not coincident with potential field gradients, suggesting that these faults are related to Alleghanian thrusts above the Silurian salt (such as the Watkins Anticline at the southern tip of Seneca Lake, Wedel, 1932). However, some of the faults deviate only slightly from trends of major gravity and magnetic gradients, suggesting that deeper faults may have guided the development of these Alleghanian shallow faults, (e.g., south of Seneca Lake, labeled "CNY" in Fig. 3).

A.6. Suspected NW-striking faults in central New York

The suspected NW-striking Owasco and Skaneateles faults (Fig. 5) are defined by the NW-striking gradients of a gravity low between Owasco and Skaneateles lakes (labeled "OS" in Fig. 3), as well as by topographic and E97 lineaments (Figs. 2 and 5). The northwest extension of the Owasco Fault may be the eastern Auburn Fault (Fig. 5). To the southeast, the gravity low is on strike with a major CSD marked by a cross-strike gradient in the Rome Trough gravity low (labeled "RTCS" in Fig. 3) and by NW-striking magnetic highs (labeled "RTCS" in Fig. 4b). The origin of this NW-striking zone is probably similar to the parallel Lawrenceville–Attica lineament: a transfer zone during Iapetan opening rift tectonics followed by reactivations during the Phanerozoic orogenies.

A.7. Suspected faults in eastern New York

Northeast-striking E97 lineaments and topographic lineaments, such as the Susquehanna River Valley, follow the northwest margin of the NE-striking Scranton Gravity High (Fig. 3). Suspected faults along these lineaments, the Susquehanna River/Scranton Gravity High faults, can be extended along-strike to the faults in the Mohawk Valley (Fig. 5) that exhibit significant stratigraphic throw of assumed Taconic age—over 500 m down-on-the-east offset is calculated for the Hoffmans and Saratoga–McGregor faults (Bradley and Kidd, 1991). To the northwest, NE-striking E97 lineaments coincident with magnetic anomalies suggest the presence of additional suspected faults such as the Utica East Fault (Fig. 5) that parallel the Susquehanna River/Scranton Gravity High faults. The Utica East Fault is approximately on strike with Ordovician faults mapped to the northeast, including the City Brook and Buttermilk Creek faults.

The origin of the Scranton Gravity High and associated faults are enigmatic (e.g., Diment et al., 1980), but the amplitude of the anomaly suggests crustal dimensions (e.g., a site of asthenospheric upwelling; Eckert, 1985). The asthenospheric upwelling could have occurred beneath a detachment zone during Iapetan rifting or Rome Trough development. The trend and location of the faults are consistent with such an interpretation, if the proposed trend and location of the Rome Trough in NYS is correct (e.g., Harper and Laughrey, 1987). If this model is correct, then the Susquehanna River/Scranton Gravity High faults first developed as Iapetan rift faults and were then reactivated during the collisional Taconic event, as evidenced by the Hoffmans and Saratoga–McGregor faults in the Mohawk Valley. The faults were probably reactivated during the Acadian and Alleghanian orogenies. Other models suggest that the gravity high is related to Alleghanian tectonics or to asthenospheric upwelling during present Atlantic rifting. In these less likely models, the Rome Trough/Iapetan opening faults guided the later development.

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The Unique Environmental Impacts of Horizontally Hydrofracking Shale Gas

By James L. Northrup

The hydrofracking of horizontal wells in shale gas formations presents a threat to aquifers that is qualitatively and quantitatively different than the threats posed by vertically fracked wells. The rapid development of this technology has outstripped the ability of most regulatory agencies to effectively deal with the environmental threat to aquifers and surface drinking water over wide areas of the United States where shale gas deposits are found.

1. The horizontal hydrofracking (HHF) of shale strata is not dissimilar from exploding a bomb underground. The pressures involved and the amount of fluid moved would qualify the hydrofrack as a large, powerful explosion capable of producing earthquakes, such as the tremor measuring 2.8 on the Richter Scale on June 2, 2009 at Cleburne, Texas. ***The pressures, volumes, and horizontal configuration of the well make it more likely that it will pollute aquifers than a conventional vertical well.***

2. Frack Pressures – The fracking pressure in a shale gas well has to be extreme in order to break up the rock – as much as 15,000 pounds per square inch (psi).[1] That is equivalent to the water pressure six miles deep in the ocean. By comparison, a thermobaric "air bomb" used in Afghanistan has an explosive pressure of about 500 psi, and it can be heard up to 100 hundred miles away.[2] ***From a pressure standpoint, the horizontal hydrofracturing of shale is effectively the explosion of a pipe bomb underground.***

3. Volume of Fracking Fluids – Since the fracked area itself can be quite long, the amount of fracking fluids in a shale gas well can exceed a million gallons. That is equivalent to about fifty (50) residential swimming pools; or by weight, approximately 2,500 automobiles. ***Based on the volume of fluids moved, the fracking of a shale formation amounts to a massive water bomb***.

4. Faulting as Pathways into Aquifers – The fact that the fracked area of a well is horizontal and of a considerable length simply increases the odds that some vertical faulting or micro faulting will be encountered (figure 1).

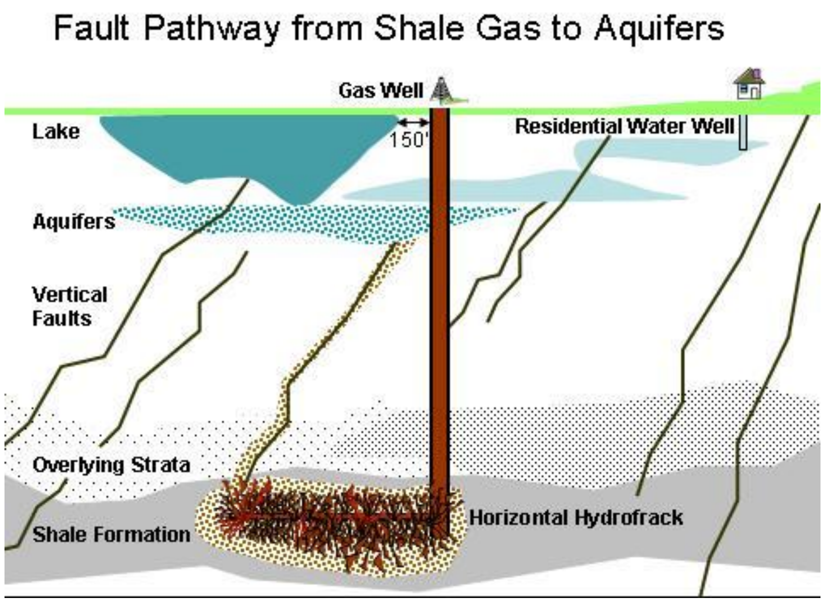

Figure 1.

Since 3-D seismic is not typically done on shale gas laterals, there is a significant risk of encountering faulting. As quoted in a recent report on an article in E&P (*Exploration & Production)* Magazine: "One statement of Brooks' that I have trouble with, having myself worked several Gas Shale Plays utilizing

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1 http://en.wikipedia.org/wiki/Hydraulic_fracturing

2 http://en.wikipedia.org/wiki/Thermobaric_bomb

3D Seismic, is that 'Blanket formations have reduced the need for seismic analysis to identify drilling prospects.' (p. 8). With proper interpretation, disasters can be avoided, and the wise operators avail themselves of 3D Seismic to prevent those disasters. Faulting of the objective Gas Shale, if not addressed, can definitely create completion issues or even cause the horizontal laterals to go 'out of zone' if not recognized." [3] In layman's language, this means that in shale formations, once the presence and thickness of the formation is established, the drilling companies do not perform further seismic data collection, which would lead to identifying faulting in the area. (This is not the case with most vertical wells, many of which depend on 3D seismic for success.) ***Unfortunately, the lower tier of New York State is riddled with likely major faults (figure 2) and with localized faulting that has not been sufficiently mapped.[4] If the frack hits any vertical faulting, the faults can be opened up as pathways for the gas and fracking fluid to enter strata above the shale, including aquifers.***

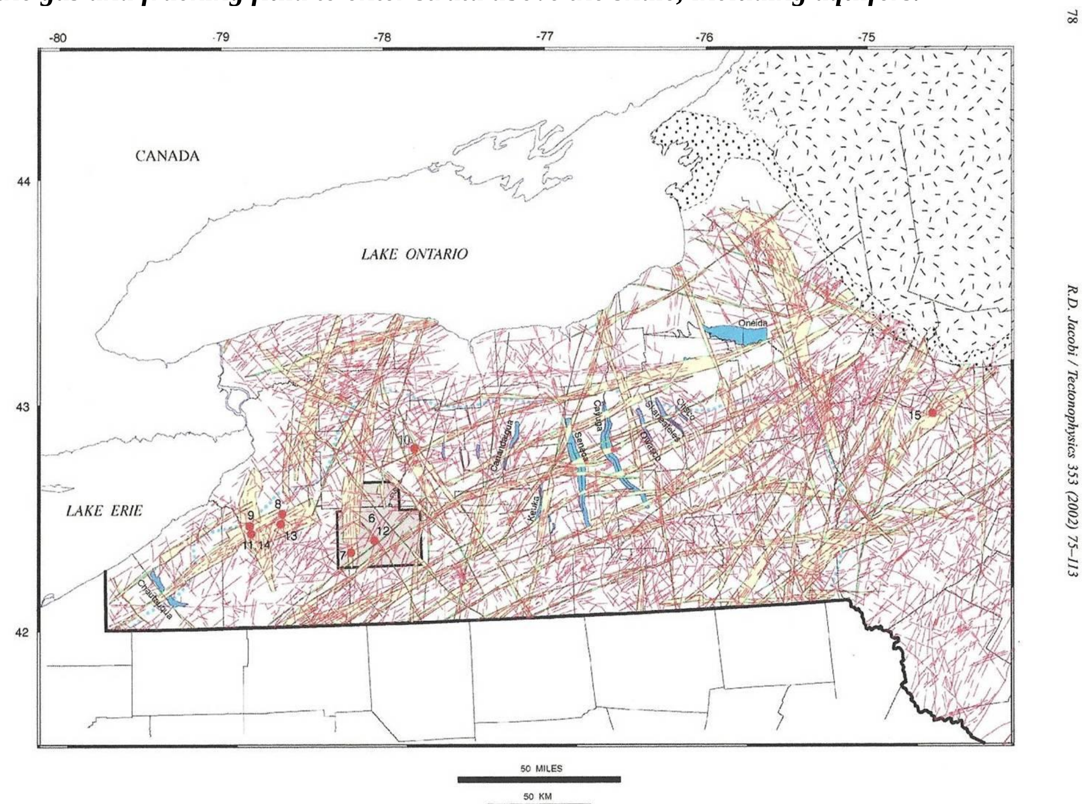

Figure 2: Faults in Southern New York

5. Higher Porosity and Permeability as Pathways into Aquifers – In some areas, it is axiomatic that the shale formation is less permeable and less porous than other oil and gas bearing strata. In the Fort Worth Basin of Texas, the local Barnett Shale was bypassed for more porous, more permeable strata. When the shale is fractured, the frack may also frack less permeable adjacent strata. This in turn could release gas and fracking fluid into the more permeable strata. ***If these strata communicate with an aquifer, they can serve as a pathway for gas and fracking fluid to get into the aquifer, polluting it. Unfortunately, there are sizeable aquifers over the Marcellus and Utica Shales (figure 3).***

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[3] http://www.glgroup.com/News/Excellent-Analysis-of-Gas-Shales-Capabilities-Benefits-and-Problems-for-2010-46505.html

[4] Jacobi, Robert D., 2002, "Basement faults and seismicity in the Appalachian Basin of New York State," *in* Neotectonics and Seismicity in the Eastern Great Lakes Basin, R. H. Fakundiny, R. D. Jacobi, and C. F. M. Lewis (eds.): Tectonophysics, v. 353, p.75-113.

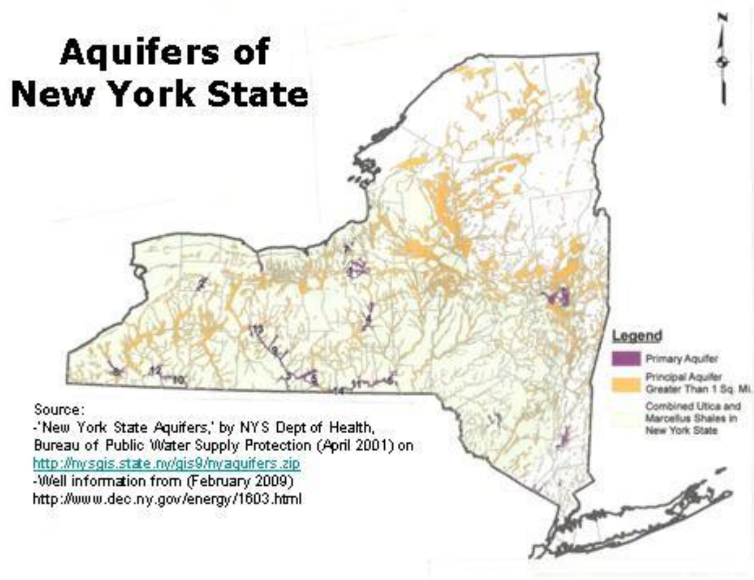

Figure 3.

6. Separation and Migration of Fracking Fluids into Aquifers - While the amount of chemicals in the fracking fluid are small on a percentage basis, they include hydrocarbons, such as benzene and diesel fuel,[5] which are lighter than water and can separate from the water after being introduced into the fracked area. If communication is established with an aquifer – either via faulting or via higher porosity strata - the fracking chemicals, none of which are potable – can rise higher into the formation, polluting the water. ***When water wells are contaminated by hyrdofracking, this separation of the lighter oils accounts for their disproportionate presence in water samples.***

7. Introduction of Natural Gas into Aquifers – Either via faulting or by penetrating a higher permeability formation, the natural gas released by the frack can enter aquifers. ***Since natural gas is made up of non-potable chemicals – propane, butane, methane, etc. – it can and does pollute water-bearing strata.***[6]

8. Horizontal Orientation Increases Likelihood of Pollution – Unlike a vertical well, the lateral section of an HHF is much more likely to go under surface water sources - lakes, streams, springs, and rivers. This in turn increases the likelihood of exposing such water bodies via faulting to fracking fluids and natural gas.

9. Size of the Formation – The extent of shale gas formations in the United States is extensive – far greater than other oil and gas formations, including some considered giants, like the Permian Basin.[7] These shale gas deposits are often located near heavily populated areas – as in New York – which are far more environmentally fragile than oil fields in flat, xeric environments, such as the Yates Field in New Mexico. ***The mere extent of the shale gas deposits should be sufficient reason for heightened environmental controls.***

10. Lack of Protection for Municipal Surface Drinking Water – Regulatory oversight of HHF near drinking water sources varies dramatically from state to state. For instance, in Texas, virtually all municipal surface drinking water sources are reservoirs owned or controlled by municipal water districts or municipalities. Drilling next to or under such a reservoir would come under the scrutiny of the municipality that owns the water. No such protections are available to most New Yorkers. The municipalities that use state-owned lakes for drinking water do not control the lakes or the shoreline. New York City is an exception to this, since it owns and operates drinking water reservoirs. ***Other New York citizens have no such jurisdictional safeguards.***

[5] http://en.wikipedia.org/wiki/Hydraulic_fracturing
[6] http://en.wikipedia.org/wiki/Benzene
[7] http://en.wikipedia.org/wiki/Marcellus_Formation

11. **Conclusions** – While the toxicity of the chemicals used in horizontal hydrofracking of shale gas may be no worse than vertical conventional wells, the process has unique characteristics that make aquifers more vulnerable to this technology. ***The horizontal hydrofracking of shale gas is a potential delivery mechanism for toxic chemicals and natural gas into aquifers. The extent of such shale gas deposits indicates that their exploitation can cause unprecedented environmental problems.***

    A. The pressures and volumes involved in HHF are massive. If the frack encounters any vertical faulting or micro faulting or if the frack enters a higher permeability strata above the shale, the immense pressure of the frack can expose areas outside the shale to gas and fracking fluids. The gas pressures of a successful well will insure that the gas goes "out of zone".

    B. The horizontal orientation of the fracked area increases the odds that a vertical fault or micro faulting will be encountered. That is, the well bore is more likely to drill through a fault – perpendicularly – than if the well bore were vertically "parallel" to vertical faulting. Such horizontal orientation greatly increases the likelihood that a HHF well bore will go under surface water sources – rivers, streams and lakes – potentially exposing them to pollutants via faulting.

    C. Municipal surface drinking water is particularly vulnerable to being polluted by HHF activity, if the users of the drinking water – the municipalities – do not own the water source. They will have no oversight over drilling near or under the lakes that supply their water. The extent of shale gas deposits in the United States threatens many such water supplies.

We recommend:

- **That drilling companies be fully subject to the regulations under the Safe Drinking Water Act,** as they were prior to 2005.

- **That seismic data be collected on each new lateral section to be fracked**. Such seismic data will show if any faulting is present in the target fracking zone and if that faulting communicates with any aquifers. This will address the risks of polluting aquifers via localized faulting, having the frack go out of zone, spills, or well casing failures into aquifers. If the seismic data shows that there is any chance that the frack zone will communicate with an aquifer, drilling and fracking should not be allowed to proceed.

James L. Northrup was in the energy business for over thirty years, having been a planning manager at Atlantic Richfield (ARCO), an independent oil and gas producer, and an owner of onshore and offshore drilling rigs. He attended Brown University and has an MBA from the Wharton School of Business. He is a member of the board of directors of Otsego 2000.

Chemical and Biological Risk Assessment for Natural Gas Extraction in New York

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Sustainable Otsego

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Summary:

Over the last decade, operators in the natural gas industry have developed highly sophisticated methods and materials for the exploration and production of methane from unconventional reservoirs. In spite of the technological advances made to date, these activities pose significant chemical and biological hazards to human health and ecosystem stability. If future impacts may be inferred from recent historical performance, then:

- Approximately two percent of shale gas well projects in New York will pollute local ground-water over the short term. Serious regulatory violations will occur at more than one of every ten new shale gas projects.

- More than one of every six shale gas wells will leak fluids to surrounding rocks and to the surface over the next century.

- Each gas well pad, with its associated access road and pipeline, will generate a sediment discharge of approximately eight tons per year. If not sequestered from local waterways, these sediments will further threaten federally endangered mollusks and other aquatic organisms.

- Construction of access roads and pipelines will fragment field and forest habitats, further threatening plants and animals which are already species of concern.

- Some chemicals in ubiquitous use for shale gas exploration and production, or consistently present in process wastes, constitute human health and environmental hazards when present at extremely low concentrations. Potential exposure effects for humans include poisoning of susceptible tissues, endocrine disruption syndromes, and elevated risks for certain cancers.

- Exposures of gas field workers and neighbors to toxic chemicals and noxious bacteria are exacerbated by certain common practices, such as air/foam-lubricated drilling and the use of impoundments for flowback fluids. These methods, along with the intensive use of diesel-fueled equipment, will degrade air quality and may cause a recently described "down-winder's syndrome" in humans, livestock and crops.

- State officials have not effectively managed oil and gas exploration and production in New York, evidenced by thousands of undocumented or improperly abandoned wells and numerous incidents of soil and water contamination. Human health impacts from these incidents may include abnormally high death rates from glandular and reproductive system cancers in men and women. Improved regulations and enhanced enforcement may reasonably be anticipated to produce more industry penalties, but not necessarily better industry practices, than were seen in the past.

Overall, proceeding with any new projects to extract methane from unconventional reservoirs by current practices in New York State is highly likely to degrade air, surface water and ground-water quality, to harm humans, and to negatively impact aquatic and forest ecosystems. Mitigation measures can partially reduce, but not eliminate, the anticipated harm.

Introduction:

Natural gas production from hydrocarbon-rich shale formations is probably the most rapidly developing trend in onshore oil and gas exploration and production today. "In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring changes to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development." (1)

Prominent features of shale gas development, which distinguish it from conventional gas extraction activity, are the use of horizontal drilling and high-volume hydraulic fracturing. While these technologies certainly lead to well projects which are orders of magnitude larger than traditional gas wells, and enable energy development companies to pursue projects in places which historically weren't commercially viable (such as New York's Southern Tier), gas exploration and production have never been free of risk. No attempt is made here to isolate horizontal drilling or hydraulic fracturing from any other processes used for gas extraction and transportation, inasmuch as the term "fracking" is understood by a majority of Americans as emblematic of the entire shale gas industry (2). Therefore, the objective is to evaluate risk related to the industry as a whole.

The working hypothesis of this work is that recent historical performance may be used to predict future performance of the gas industry. Data sources predominantly include official state, federal or industry reports. Using similar sources, industry analysts have broadly assessed environmental risks for the global oil and gas industry (3, 4). This article focuses on environmental risks which may be peculiar to New York State. Two components of risk imposed by the gas industry are evaluated here: incident frequency and impact. Frequency data are presented in Part 1, and chemical and biological aspects of impact are discussed in Part 2.

Part 1: Incidents of Contamination Related to Natural Gas Extraction

Official incident reports from various jurisdictions are cited below, and to evaluate them together requires application of a uniform context. One approach to context compares gas industry incidents over any period to the total number of gas wells that ever existed in the report region. In the author's judgment, this approach fails to accommodate the facts that many gas wells were "spudded" prior to any official record-keeping (let alone incident reporting), and most reported gas well mishaps arguably occur during initial drilling and stimulation. This author's contextual approach is to compare incident reports to the total active gas wells operating in a jurisdiction at the close of the reporting period, and to offer the number of new gas well projects started in that period, where available, as an alternative comparison.

Other States:

Data from Colorado indicated that there were 1549 spill incidents related to natural gas extraction activities in the period from January 2003 to March 2008; the Congressional Sportsmen's Foundation estimated that 20% of these (310) impacted groundwater (5). The New Mexico Oil Conservation Division recorded 705 groundwater-contaminating incidents caused between 1990 and 2005 by the gas industry (6). Compared to totals of 25,716 and 40,157 producing gas wells in Colorado and New Mexico, respectively (7), these data suggest that 6% of western region gas projects suffer serious mishaps, and that natural gas development in western states degrades groundwater quality at a rate of 1.2 to 1.8 incidents per 100 gas wells. Data from West Virginia lead to a generally similar conclusion of groundwater impacts from approximately 1.5% of active gas wells (6, 7), while Utah reported a violations rate of 11.5% without expressly indicating the extent of documented groundwater contamination (8).

The Pennsylvania Land Trust reported 1610 DEP violations in the Commonwealth between January 2008 and late August 2010, of which 1052 were judged likely to impact the environment (9). The Land Trust report appears to have included incidents related only to those gas wells which targeted the Marcellus shale formation. What fraction of the then-active 57,356 gas wells in Pennsylvania targeted that formation was not reported (7), but 2008 – 2010 records show that 25% of the DEP's gas well inspections were performed on Marcellus wells (10). Comparing 1052 serious incidents to an upper limit of 14,340 Marcellus wells, these data suggest that at least 7% of Pennsylvania's shale gas projects had negative impacts on their environment.

Pennsylvania's gas industry incident data are available for independent review since, responding to Act 15, signed into law by Governor Rendell in March, 2010 (11), the Department of Environmental Protection developed the DEP Oil and Gas Electronic Reporting website (10). **Table I** summarizes incidents from (a) all formations and (b) Marcellus shale formations for the period from January 2008 through the end of 2010.

Table I: Pennsylvania Gas Industry Inspections, Violations and Enforcements

Year	Formations	Inspections	Violations	Enforcements
2008	All	937	1447	662
	Marcellus	130	179	122
2009	All	1801	3159	693
	Marcellus	314	639	190
2010	All	1500	2721	721
	Marcellus	634	1227	308
Total	All	4238	7327	2076
	Marcellus	1078	2045	620

These records indicate that total violations and serious violations (enforcements) correlate well with the numbers of inspections, but Marcellus projects tended to generate violations and enforcements at rates that increased with the passing of time. Compared to a total of 57,356 producing gas wells in the Commonwealth, the data indicate a violations rate of 12.8% and an enforcements (serious violations) rate of 3.6%. Further, they suggest that industry operators became less compliant with regulations as the Marcellus shale projects advanced: more citations produced greater penalties, but not better practices.

It could be argued that not all producing wells pose equal risk: that gas well projects which are under construction contribute greater hazards than completed wells. Compared to 20,698 total *new* gas well projects reported from January 2008 through December 2010 (12), the data in Table I indicate a serious (potentially groundwater-impacting) violations rate of 10.0%. Put another way, about one out of every ten new gas well projects in Pennsylvania has run into serious trouble over the past three years. For a more detailed analysis of incident reports from Pennsylvania, Utah and West Virginia, the reader is referred to the work of Conrad Daniel Volz (8).

New York State:

Gas industry incidents are not systematically reported by New York State, and this state's history of regulating the industry is rather complex. The first domestic gas well was drilled in the stream bed of Canadaway Creek near Fredonia in 1821 (13, 14). New York was the first state to require the plugging of abandoned wells in 1879 (13, 14), and the first New York law to protect public water supplies from contamination was passed in 1885 (15). No particular state entity existed to monitor compliance or enforce these laws, but an 1882 amendment to the well plugging law offered half of any collected fines to informants who reported violations (13). New York's Fisheries, Game and Forest Commission was formed in 1895 (16), and the New York State Health Department was created in 1901 (15). The Fisheries, Game and Forest Commission was reorganized as the Department of Conservation in 1910 – 1911 (16). Legislation was adopted in 1933 to allow leasing of state lands for oil and gas drilling (13). In 1949, the Comprehensive State Water Pollution Control Act was passed (15).

New York repealed all previous oil and gas-related legislation in 1963, and amended Conservation Law to consolidate the Conservation Department's control of that industry's future development in the state. In 1966 the Department began to keep records on oil and gas wells (16). On April 22, 1970 (the first Earth Day), the New York State Department of Environmental Conservation (DEC) was created from the old Conservation Department, elements of the Health Department and a variety of other state commissions. The state's Environmental Conservation Law (ECL) was extensively recodified in 1972 (16).

In 1978, New York passed the State Environmental Quality Review Act (SEQRA), which was revised in 1987 and again in 1996 (17). This law required all state agencies to consider the environmental impact of all activities which they carried out or permitted, issuing environmental impact statements as needed. In response, the DEC's Division of Mineral Resources (DMN) prepared a Generic Environmental Impact Statement on Oil, Gas and Solution Mining (GEIS), issued as a draft in 1988 and finally adopted with revisions in 1992 (18). Although not accompanied by a "rules package" (19), this document became the primary guide for permit conditions attached to new oil and gas well projects until now (16). The DEC is currently revising a draft Supplement to the GEIS (dSGEIS) to address new technologies and issues of scale related to horizontally-drilled high-volume hydraulically fractured (HV/HF) gas well projects (20).

These laws, regulations and guidance documents constitute a diffuse, incomplete and at points inconsistent regulatory framework. For example, mineral resources laws and regulations fail to define process wastes (21, 22); "waste" is defined only as hydrocarbon product loss (23). And whether gas industry waste fluids are managed as liquids or solids depends on whether they are being transported (solids), treated (liquids), re-purposed or disposed (solids) (24 – 27). In any event, they are classified as non-hazardous (28 – 30), regardless of what is in them (31). These exceptions and exemptions contradict the definitions of pollutants found in mineral resources regulations (32) and water resources law (33). Further complicating matters, the GEIS recommended some practices that proved to be so unworkable, they are no longer used. An example was "pitless drilling", for which the rationale was that just letting waste fluids spray out onto the ground would kill fewer trees than would clearing a forested site for a wastewater pit (34). The efforts of field agents with the DEC's Bureau of Oil and Gas Regulation have arguably been hindered by such diffuse, incomplete and sometimes incompatible laws and regulations (35).

Indeed, when New York's regulatory program was reviewed in 1994 by a panel from the Interstate Oil and Gas Compact Commission, a number of deficiencies were noted (19). Among the issues were an estimated annual discharge of 360 million gallons of oil and gas well flow-back fluids directly into streams, onto land and roadways, and a legacy of approximately 60 thousand abandoned oil and gas wells. The DEC had no data on roughly half of them, and two-thirds of the wells for which they had records showed evidence that they were improperly abandoned. But the review panel considered the program's lack of resources to be its greatest deficiency (19).

The DEC Division of Mineral Resources has improved since 1994 (36), but some old problems persist. Their 2008 Annual Report, dominated by production data (consistent with their mandate (37)), estimated that 57,000 abandoned oil and gas wells remain to be dealt with, including approximately 30,000 for which the DEC still has no records (38). They are managing to plug about 200 per year, at which rate the backlog will require more than 280 years to complete if no new wells are improperly abandoned. Their 19 field agents also performed 2445 inspections in 2008, which resulted in 84 enforcement actions (a rate of 3.4%) for a total of $10,500 in fines – an average of $125 per citation (38, 39). The BOGR now has 16 field agents state-wide (39, 40) to monitor the state's 13,217 oil and gas wells – more than 800 wells for every inspector (41).

Walter Hang of Toxics Targeting, Inc. reported 270 ground-water polluting incidents since 1979, based on data from a DEC spills hotline (42). Compared to 13,217 active wells, this would suggest a ground-water pollution rate of 2.0% for oil and gas extraction projects. However, there is controversy about whether all the reported incidents actually impacted ground-water (43). Further complicating this analysis, problems reported directly to DEC field offices or to county health departments (lead investigators of complaints involving the gas industry according to memoranda of understanding with the DEC), were not combined with the hotline data or otherwise reported by the DEC; there were more than a hundred such complaints in Chautauqua County alone (44). Therefore, the actual number and types of gas industry incidents in New York State remain unknown, but a 2% ground-water pollution rate could arguably be considered an under-estimate.

But accidental releases of gas industry process wastes were far outweighed by the intentional discharges of these wastes directly into streams, onto land, and on roadways, as stated above (19). Studies are currently underway to evaluate the scope of harm done to surface streams and shallow aquifers in the western counties of New York where most of the discharges took place (45 – 52). Some possible human health impacts are presented in Part 2 of this article.

Long-Term Impacts:

Short-term collateral damage from gas well development constitutes only part of this industry's hazard profile. In 1992, the US Environmental Protection Agency (EPA) estimated that of 1.2 million abandoned oil and gas wells in the U.S., 200,000 were leaking (53). This represents a 16.7% failure rate; one of every six abandoned wells is releasing its contents to the surrounding area, including the surface. A Canadian research team investigated the mechanisms for these failures, and determined that concrete shrinkage which leads to well casing fissures is essentially inevitable in a fifty-year time frame. They found that this cracking was especially severe at maximum depth, and exposure of steel casings to the hot (140 – 180 °F) brines there accelerated their breakdown, permitting subterranean gases and other fluids to re-pressurize the deteriorating wells (54). Wells in regions containing mobile geological faults, such as Upstate New York (55), are also subject to casing deformation and shear (56). According to the IOGCC panel report and the DEC, New York has a "substantial abandoned wells problem", with more than 57 thousand undocumented or improperly abandoned oil and gas wells (36, 38). USGS scientists judged that some ground-water contamination cases in Chautauqua County were caused by gas wells providing portals for deep pollutants to reach the surface (44). We may reasonably expect higher percentages of gas well casings to fail over time, especially longer than fifty years. Therefore, the probability that a project scope of as few as ten modern gas wells will impact local ground water within a century approaches 100% certainty.

Part 2: Chemical and Biological Hazards From Natural Gas Extraction

Drilling Additives:

Many chemical products are used in the development of a gas well. Some examples, along with their most common applications, are shown in **Table II**.

Table II: Additive Functions in Shale Gas Extraction

Additive Type	**Examples**	**Purpose**	**Used In**
Friction Reducer	heavy naphtha, polymer microemulsion	lubricate drill head, penetrate fissures	drilling muds, fracturing fluids
Biocide	glutaraldehyde, DBNPA, dibromoacetonitrile	prevent biofilm formation	drilling muds, fracturing fluids
Scale Inhibitor	ethylene glycol, EDTA, citric acid	prevent scale buildup	drilling muds, fracturing fluids
Corrosion Inhibitor	propargyl alcohol, *N*,*N*-dimethylformamide	prevent corrosion of metal parts	drilling muds, fracturing fluids
Clay Stabilizer	tetramethylammonium chloride	prevent clay swelling	drilling muds, fracturing fluids
Gelling Agent	bentonite, guar gum, "gemini quat" amine	prevent slumping of solids	drilling muds, fracturing fluids
Conditioner	ammonium chloride, potassium carbonate, isopropyl alcohol	adjust pH, adjust additive solubility	drilling muds, fracturing fluids
Surfactant	2-butoxyethanol, ethoxylated octylphenol	promote fracture penetration	drilling fluids, fracturing fluids
Cross-Linker	sodium perborate, acetic anhydride	promote gelling	fracturing fluids
Breaker	hemicellulase, ammonium persulfate, quebracho	"breaks" gel to promote flow-back of fluid	post-fracturing fluids
Cleaner	hydrochloric acid	dissolve debris	stimulation fluid, pre-fracture fluid
Processor	ethylene glycol, propylene glycol	strip impurities from produced gas	post-production processing fluids

Individual additives are typically used in multiple stages of the drilling process; most hydraulic fracturing additives are also used in drilling fluids (or "muds") (57). Rare exceptions include bentonite and barium sulfate, which are used almost exclusively in drilling muds and packer slurries, and hemicellulase enzyme, used solely in post-fracturing fluids. Even the chemicals used for post-production purification may also be used as solvents in drilling muds (57).

The majority of chemical products used by the gas industry have not been fully tested for human or environmental toxicity (58, 59). Of those which have, a minority (*e.g.,* bentonite, guar gum, hemicellulase, citric acid, acetic acid, potassium carbonate, sodium chloride, limonene, polyethylene glycol and mineral oil) pose no significant hazards to humans or other organisms as utilized in gas extraction processes.

Several other additive chemicals, including ammonia, methanol, ethanol, 2-propanol, 1-butanol, thioglycolic acid, acetophenone, sodium perborate tetrahydrate, diammonium peroxydisulfate and hydrochloric acid, are moderately or acutely toxic to humans or aquatic organisms when encountered in concentrated forms (60 – 69), but as used by the natural gas industry, they end up greatly diluted, and so impose relatively modest hazards (58). More significant issues with these chemicals would be anticipated from storage sites, trucking accidents while they are being transported to remote well sites via rural roads, and staging at well sites.

However, a few chemical products in widespread use, including in exploratory wells, pose significant hazards to humans or other organisms, because they remain dangerous even at concentrations near or below their chemical detection limits. These include the biocides glutaraldehyde, 2,2-dibromo-3-nitrilopropionamide (DBNPA) and 2,2-dibromoacetonitrile (DBAN), the corrosion inhibitor propargyl alcohol, the surfactant 2-butoxyethanol (2-BE), and lubricants containing heavy naphtha. Precisely because of the hazard these chemicals pose even when they are extremely diluted, they are considered in some detail in this section. (Note: CAS No. refers to a unique identifier assigned to every known substance by the Chemical Abstracts Service Registry.)

Glutaraldehyde:

Glutaraldehyde (CAS No. 111-30-8) is a biocide used widely in drilling and fracturing fluids. Along with its antimicrobial effects, it is a potent respiratory toxin effective at parts-per-billion (ppb) concentrations (70); a sensitizer in susceptible people, it has induced occupational asthma and/or contact dermatitis in workers exposed to it, and is a known mutagen (i.e., a substance that may induce or increase the frequency of genetic mutations) (70, 71). It is readily inhaled or absorbed through the skin. In the environment, algae, zooplankton and steelhead trout were found to be dramatically harmed by glutaraldehyde at very low (1 – 5 ppb) concentrations (72).

DBNPA:

2,2-Dibromo-3-nitrilopropionamide (DBNPA) (CAS No. 10222-01-2) is a biocide finding increasing use in drilling and fracturing fluids. It is a sensitizer, respiratory and skin toxin, and is especially corrosive to the eyes (73). In the environment, it is very toxic to a wide variety of freshwater, estuarine and marine organisms, where it induces developmental defects throughout the life cycle. In particular, it is lethal to "water fleas" (*Daphnia magna*), rainbow trout and mysid shrimp at low (40 to 50 ppb) concentrations, and is especially dangerous to Eastern oysters (74). Chesapeake Bay oysters are killed by extremely low (parts-per-trillion, ppt) concentrations of DBNPA, well below the limit at which this chemical can be detected.

DBAN:

Dibromoacetonitrile (DBAN) (CAS No. 3252-43-5) is a biocide often used in combination with DBNPA, from which it is a metabolic product (with the release of cyanide). Its human and environmental toxicity profiles are similar to that of DBNPA, except that DBAN is also carcinogenic (75). DBNPA and DBAN appear to work synergistically. In combination, the doses at which these biocides become toxic are significantly lower than when they are used separately. In other words, it takes much less of these chemicals to exert toxic effects when they are used together, although the specific degree of potentiation has not been publicly reported.

Propargyl Alcohol:

Propargyl alcohol (CAS No. 107-19-7) is a corrosion inhibitor that is very commonly used in gas well construction and completion. This chemical causes burns to tissues in skin, eyes, nose, mouth, esophagus and stomach; in humans it is selectively toxic to the liver and kidneys (76). Propargyl alcohol is a sensitizer in susceptible individuals, who may experience chronic effects months to years after exposure, including rare multi-organ failure (77). It is harmful to a variety of aquatic organisms, especially fathead minnows, which are killed by doses near 1 ppm (78).

2-BE:

2-Butoxyethanol (2-BE), also known as ethylene glycol monobutyl ether (EGBE) (CAS No. 111-76-2), is a surfactant used in many phases of gas exploration and extraction. It comprises a considerable percentage of Airfoam HD, commonly used for air-lubricated drilling (79). Easily absorbed through the skin, this chemical has long been known to be selectively toxic to red blood cells; it causes them to rupture, leading to hemorrhaging (80). More recently, the ability of EGBE at extremely low levels (ppt) to cause endocrine disruption, with effects on ovaries and adrenal glands, is emerging in the medical literature (81). This chemical is only moderately toxic to aquatic organisms, with harm to algae and test fish observed with doses over 500 ppm (80).

Heavy Naphtha:

Heavy naphtha (CAS No. 64741-68-0) refers to a mixture of petroleum products composed of, among other compounds, the aromatic molecules benzene, toluene, xylene, 1,2,4-trimethylbenzene and polycyclic aromatic hydrocarbons including naphthalene. It is used by the gas industry as a lubricant, especially in drilling muds. This material is hazardous to a host of microbes, plants and animals (82). Several of the mixture's components are known to cause or promote cancer. If released to soil or groundwater, several components are toxic to terrestrial and aquatic organisms, especially amphibians, in which it impedes air transport through the skin.

Flowback Fluids:

Irrespective of chemical additives used for drilling, Marcellus shale contains several toxic substances which can be mobilized by drilling. These include lead, arsenic, barium, chromium, uranium, radium, radon and benzene, along with very high levels of sodium chloride (83). These components make flowback fluids hazardous without any added chemicals, and are often among the analytes most easily measured by potential waste fluid treatment plant operators (**Figure 1**).

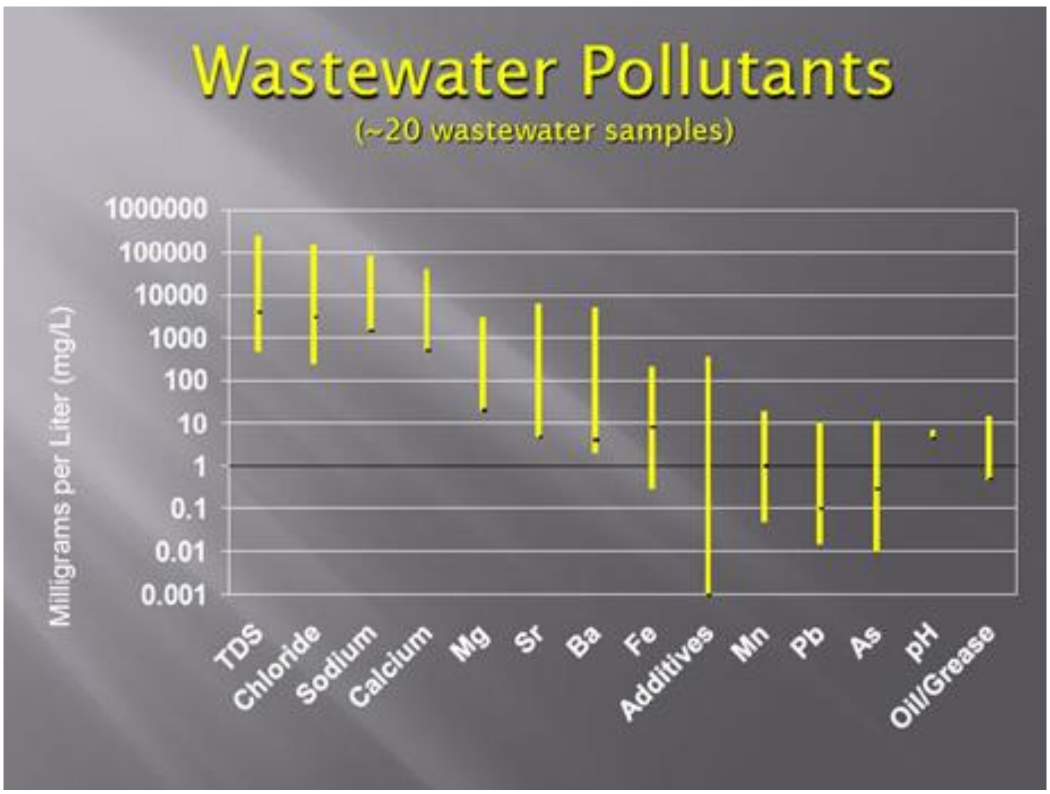

Figure 1: Wastewater Pollutants (84)

Because of to their significant toxicity at low (ppb) concentrations, and the fact that drill cuttings are often not removed, but rather are buried on-site, several of these flowback fluid and cuttings components (83) are discussed below: barium, lead, arsenic, chromium, benzene and technologically enhanced naturally occurring radioactive materials.

Barium (Ba):

Barium is a toxic heavy metal commonly found in Marcellus shale well flowback fluids (85). Exposure to soluble salts (not the sulfate), which may occur by ingestion, absorption or inhalation, may induce drops in tissue potassium levels, and by this mechanism it is selectively toxic to the heart and kidneys (86). Further, barite (barium sulfate), used as a weighting agent in drilling muds, reacts with radium salts in shale, forming radioactive scale on metal parts (such as the drill "string") which then are subsequently brought to the surface (57); in these reactions, barite is converted to more soluble (i.e. more toxic) barium salts.

Lead (Pb):

The poisonous nature of lead has been known for centuries, but its ability to impair neurological development in children at very low (1 ppb) concentrations makes it a toxicant of special concern. The most sensitive targets for lead toxicity are the developing nervous system, the blood and cardiovascular systems, and the kidney. However, due to the multiple modes of action of lead in biological systems, and its tendency to bio-accumulate, it could potentially affect any system or organs in the body. It has also been associated with high blood pressure (87).

Arsenic (As):

Arsenic, another component of black shale (83), has also been known as a poison for hundreds if not thousands of years. The most sensitive target tissue appears to be skin, but arsenic produces adverse effects in every tissue against which it has been tested, especially brain, heart, lung, the peripheral vascular system, and kidney (88). Arsenic is harmful below one part per trillion (ppt) in water, and is a confirmed carcinogen.

Chromium (Cr):

Chromium, also found in Marcellus shale (89), may be an essential nutrient required in extremely small doses (µg per day), but the biological system it supports is not currently known. Exposure to elevated doses by inhalation, ingestion, skin or eye contact may lead to respiratory, gastrointestinal, reproductive, developmental and neurological symptoms

(90). Sensitization-induced asthma and allergy have also been reported. However, at very low concentrations, particularly of potassium dichromate or strontium chromate (the hexavalent form, as found in shale rock) (91), the major hazard posed by chromium is as a carcinogen, especially in stomach and lung tissues (90).

Benzene:

Benzene, a known shale constituent (83), was briefly considered above as a component of heavy naphtha. In ppb concentrations, the primary hazard from this compound is due to its proven ability to cause acute non-lymphocytic leukemia (92).

Technologically Enhanced Naturally Occurring Radioactive Materials (TENORM):

The use of lubricants and "slickwater" additives along with hydraulic fracturing for oil and gas production have been shown to mobilize naturally occurring radioactive materials, including uranium- 238, radium-226 and radon-222 (93). This has been identified as one of the greatest challenges facing the American gas industry today (94). Of these, radon is of special concern because as a gas it is extremely mobile, and it is intensely radioactive (94). Exposure by inhalation or ingestion typically results in migration to the lungs, which are susceptible to damage from its nuclear decay; exposure to radon is considered the second leading cause of lung cancer after tobacco smoking (95). Radon was detected at levels above 300 pCi/L (a drinking water limit proposed by the USEPA), in a majority of groundwater samples collected in New York State by USGS investigators (50 – 52). However, whether the high levels of radon in drinking water may be related to past or present oil and gas development in those locales has never been studied; they could possibly be due to fracture intensification domains in New York's subsurface geology (55).

4-NQO:

In addition to the above shale constituents, one chemical compound was consistently encountered in flowback fluids from Marcellus gas wells in Pennsylvania and West Virginia: 4-nitroquinoline-1-oxide (4-NQO) (96). This is one of the most potent carcinogens known, particularly for inducing cancer of the mouth (97). It is not used as a drilling additive and is not known to occur naturally in black shale; no studies have been published to date with respect to what chemical interactions account for its consistent presence in flowback fluids. However, it is dangerous at parts-per-trillion (ppt) concentrations, well below its levels reported in gas well flowback fluids (96).

Inadequately Treated Drilling Wastes:

Treatment of gas industry process wastes by publically-owned sewage treatment plants or privately-owned industrial waste treatment plants has been found to be not completely adequate to maintain water quality in receiving streams. Pennsylvania's Monongahela River was subject to spikes in total dissolved solids (TDS) in late 2008 and throughout 2009. Seeing that gas drilling wastes constituted up to 20% of the waste treated at some facilities discharging into the basin, the Pennsylvania DEP ordered these facilities to restrict their intake of drilling waste water (98). More recently, elevated levels of bromide in the Allegheny River, ostensibly from gas drilling wastes, have caused concern for a number of water treatment managers in southwestern Pennsylvania (99). Direct tests of effluent from a facility dedicated to treating gas drilling wastes showed that the plant was discharging extraordinary levels of bromide and other contaminants into a tributary of the Allegheny River, in flagrant violation of its permit (100).

Biological Contamination:

Rock strata beneath the earth's surface are populated by microscopic organisms, and the advent of air-lubricated drilling (without biocides) has introduced a risk of contaminating surface (fresh) water zones with bacteria and other microbes from deeper (brine) layers, where they often flourish. Of particular concern are sulfate-reducing bacteria, especially *Desulfovibrio desulfuricans*, a facultative anaerobe that thrives in fresh water where some sulfate (such as is present in pyrite or hematite) is available (101), (**Figure 2)** (102).

Figure 2: Biofilm of *Desulfovibrio desulfuricans* Growing on a Hematite Surface

These bacteria are especially prevalent and aggressive in oil and gas producing regions, where they avidly form living black, sticky films in water wells and other structures (103). There they produce hydrogen sulfide (H_2S), characterized by a "rotten eggs" smell. Rock strata rich in gas are often also rich in this bacterium, and exposure to hydrogen sulfide along with methane raises significant health concerns –neurological syndromes in humans and, in livestock, elevated birth defect rates and diminished herd health. At high concentrations, hydrogen sulfate is lethal (104).

The now-common use of air-lubrication (without biocides) while drilling the top one- to three thousand feet of gas wells (105) risks contaminating fresh water aquifers with sulfate-reducing bacteria from the deeper strata, but there is no clear evidence that this water well fouling mechanism is recognized by New York state regulators.

Transportation Infrastructure:

Gas well development requires the construction of well pads, access roads and pipelines. These structures, as well as the construction projects that produce them, pose significant environmental hazards from accelerated erosion (106, 107). A report for the USEPA determined an average annual sediment yield of 7.4 metric tons per hectare in Denton, Texas (108). After adjusting for the difference in average rainfall amounts in Denton, TX and New York State, and estimating one hectare (2.47 acres) as a typical land disturbance for a gas well pad, access road and pipeline (109), the sediment load for a New York gas well is expected to average 8.5 tons per year. Degradation of existing roads, culverts and bridges by excessive truck traffic also accelerates erosion and increases deposition of road dust into waterways (110). Organisms which are critical for maintaining stream water quality and are especially vulnerable to sediment runoff and siltation damage include filter-feeding macroinvertebrates (111) and bivalve mollusks, including the federally endangered dwarf wedgemussel (112, 113).

In addition to soil erosion issues, all-weather access roads also lead to the fragmentation of fields and forests (104, 114). One consequence is declining critical core populations of Allegheny woodrats, snowshoe hares, and plants such as tamarack and red spruce trees, and yellow lady slipper orchids, all of which require interior woodland habitats (114). Woodland amphibians, including marbled, blue-spotted and Jefferson's salamanders, which are species of special concern, are also sensitive to habitat fragmentation (115). Some grassland species are exquisitely sensitive to habitat fragmentation: over the past forty years, New York has seen a decline of 80 to 99% in the abundance of Henslow's Sparrow, Grasshopper Sparrow, Vesper Sparrow, Upland Sandpiper, Horned Lark, Eastern Meadowlark, Savannah Sparrow, Northern Harrier and Bobolink (116). Therefore, the DEC is developing Grassland Focus Areas in attempts to restore populations of Short-eared Owl and Sedge Wren in addition to the above bird species (116). This begs the question of how much fragmentation from shale gas development can be sustained without compromising these habitat restoration efforts (117).

Air Quality Impacts:

Gas well projects can generate uniquely severe air quality problems, as volatile organic compounds (VOC's) from flowback fluid impoundments, polycyclic aromatic hydrocarbons (PAH's) from incompletely-combusted fuel and fugitive methane emissions combine with nitrous oxides (NOx) from diesel exhaust (118) to form ground-level ozone. To paraphrase the pioneering work of Theo Colborn et al (119): "This ozone can burn the deep alveolar tissue in the lungs, causing its premature aging. Chronic exposure can lead to asthma and chronic obstructive pulmonary diseases (COPD). Ozone combined with [fine] particulate matter produces smog which has been demonstrated to be harmful to humans as measured by emergency room admissions during periods of elevation. Gas field ozone has created a previously unrecognized air pollution problem in rural areas, similar to that found in large urban areas, and can spread up to 200 miles beyond the immediate region where gas is being produced. Ozone not only causes irreversible damage to the lungs, it is similarly damaging to conifers, forage, alfalfa, and other crops commonly grown in the U.S." (119).

In addition to impacts from ground-level ozone, fugitive emissions of methane from wellheads, pipelines and storage facilities, along with combustion (primarily diesel) exhausts related to construction and pipeline pressurization, combine to put the total greenhouse gas emissions from shale gas extraction on par with greenhouse gas emissions from coal (120). Further, Robert Howarth's analysis suggests that "clean" natural gas exerts a greater "carbon footprint" than diesel oil when the intensive efforts required to extract gas from shale are taken into account (120). Therefore, the desirability of natural gas as a "transition fuel" is questionable when the resource must be extracted from unconventional reservoirs by energy-intensive means: it may be no better than coal.

Potential Health Effects:

Hazards that accompany the above chemicals and microbes and physical agents have to this point been considered individually. They clearly don't occur individually. No investigations of interactions among all these materials have been reported to date. However, this author has been contacted by officials with the National Institute of Safety and Occupational Health, Centers for Disease Control (NIOSH/CDC), who requested any information that might shed light on a group of clinical symptoms, presented by patients in southwestern Pennsylvania and the state of West Virginia, which is being tentatively identified as "down-winder's syndrome" (121). These symptoms, including irritated eyes, sore throat, frequent headaches and nosebleeds, skin rashes, peripheral neuropathy, lethargy, nausea, reduced appetite and mental confusion, were also reported in gas field health impact studies conducted by Wilma Subra in Texas (122) and Wyoming (123). These disparate observations are supported by a literature review of potential human health effects from gas drilling activities (124). In response, the Medical Society of the State of New York and the medical societies from Broome, Cayuga, Chenango, Chemung, Herkimer, Madison, Oneida, Onondaga, Oswego, Otsego and Tompkins Counties, and the Sixth District (Delaware and Tioga Counties), have all called for a moratorium on natural gas extraction using high volume hydraulic fracturing in New York State (125).

The proposed practice in New York of using open impoundments for large-scale capture of flowback fluids from gas wells may exacerbate the risk of this syndrome. Although most additives are greatly diluted in the drilling process, organic compounds (with the notable exceptions of DBNPA and DBAN) tend to be lighter than water; therefore they float to the surface of holding pits, where they concentrate to essentially 100% of the top layer. From there they volatilize or aerosolize into the air, from which they may be inhaled by neighbors and on-site industry workers. Partly for this reason, the states of Colorado (126) and New Mexico (127) have prohibited the use of impoundments for flowback fluids.

As mentioned in Part 1, above, the oil and gas industry was responsible for substantial contamination of soil and water in New York, particularly in our western-most counties, from 1821 to at least 1993 (44 – 52). Among other possible health concerns, there is overwhelming evidence that industrial pollutants can cause or promote cancer in humans (128). As a preliminary approach to assessing potential human health effects from exposure to that environmental pollution, cancer mortality statistics were reviewed for Chautauqua, Cattaraugus and Allegany Counties. These three counties were selected because of their historically intensive gas industry activity, documented impairment of drinking water by industrial pollution sources, and distinctively rural character (to minimize influences from industries other than oil and gas). Based on nation-wide reports for 55 different cancer types from 1950 to 1994, women in this three-county area of New York were consistently in the top bracket for deaths caused by cancer of breast, cervix, colon, endocrine glands, larynx, ovary, rectum, uterus and vagina(129). Men from the same region were consistently in the highest statistical bracket for deaths caused by bladder, prostate, rectum, stomach, and thyroid cancers (129).

While it must be noted that county-wide cancer mortality statistics don't prove a connection between the elevated numbers of cancer deaths and gas industry pollution, the industry has also never been exonerated from a contribution to the unique profile of abnormally high cancer incidence and mortality in these counties. Clearly, much more investigative work needs to be done in this regard.

Conclusions:

As stated above, the working hypothesis for this risk assessment is that future impacts may be inferred from historical performance. Therefore, cumulative chemical and biological impacts from the gas industry in New York may be predicted for projects of any scope by combining incident statistics from Part 1 with related health and environmental impacts from Part 2. For example, from a development of 10,000 gas wells (a plausible estimate according to Anthony Ingraffea) (130), the sediment run-off into nearby waterways would amount to at least 80,000 tons per year. Such a development would reasonably be expected to generate about 1,200 citations for serious regulatory violations and at least 200 incidents of groundwater contamination in the short term. Over a century, about 1,600 more leaking gas wells should be anticipated. If this scale of development takes place in a 2-county area, then significant spikes in emergency room visits for respiratory complaints and other aspects of "down-winder's syndrome" in those counties should be anticipated as well. Changes in human chronic disease profiles and impacts on domestic, aquatic and forest ecosystems would be more insidious and difficult to measure – but not necessarily less significant.

The record of New York State officials in managing gas industry impacts has been no better than those of officials in neighboring states, and may be substantially worse. Documenting harm and penalizing those in the energy industry who caused it have historically done little to mitigate that harm or prevent its re-occurrence. New York State law regarding the gas industry clearly promotes production over environmental protection (35). Therefore, there is little evidence that changes to the regulatory process will be adequate to protect New York's environment and citizens from harm caused by this industry. These conclusions essentially agree with those made by Zoback, Kitasei and Copithorne (110), Hazen and Sawyer (131) and Fuller and Hetz (132). However, they disagree with the assessment of the Ground Water Protection Council (GWPC) (36); it is possible that the GWPC maintains lower standards for public safety and health than these other evaluators.

It is hoped that this instrument will be found useful to public servants at every level in New York State, whether they serve in executive, legislative, judicial, health, safety, planning, education, or advocacy roles. Decisions we make today regarding whether or how to proceed with shale gas development here will have ramifications for generations to come.

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SBS LLC

Review of Phase II Hydrogeologic Study

Prepared for Garfield County

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Evaluation of Phase II Hydrogeologic Study for Garfield County

Executive Summary

This report reviews and integrates the results of the Garfield County Phase I and II hydrogeological investigations performed by URS and S. S. Papadopulos & Associates, respectively. The main findings can be summarized as follows:

1 – The water quality data is sufficient to establish the range of natural background chemistry and delineate the impact of petroleum activities. Impacts from petroleum activity are not currently present at levels that exceed regulatory limits. The impacts are mainly elevated methane and chloride in groundwater wells.

2 - There is a temporal trend of increasing methane in groundwater samples over the last seven years that is coincident with the increased number of gas wells installed in the Mamm Creek Field. Pre-drilling values of methane in groundwater establish natural background was less than 1ppm, except in cases of biogenic methane that is confined to pond and stream bottoms. The cases of biogenic methane can be readily identified by stale isotopic characterization of the methane. The isotopic data for the methane samples show the most of the samples with elevated methane are thermogenic in origin.

3 - Concurrent with the increasing methane concentration there has been an increase in groundwater wells with elevated chloride that can be correlated to the number of gas wells. Chloride is derived from produced water.

4 - The increasing methane and chloride will not trigger regulatory action since there is no regulated limit on methane and the majority of chloride values are below regulatory limits, however, as more gas wells are drilled the chloride value may reach the regulatory limit.

5 - Currently the only monitoring mechanism to evaluate the impact of gas well drilling and gas production to groundwater quality is the existing domestic water wells and surface water bodies.

The number of water wells (<200) and their spatial distribution is inadequate to monitor and locate potential source of contamination from the more than 1400 potential point sources (gas wells and produced water pits). There are only a few cases where COGCC has been able to identify gas wells as point sources of the observed more widespread increase in impact (West Divide Creek seep and the Amos well).

Introduction

The purpose of this report is to perform an evaluation of water and geologic data collected in an area south of Silt, Colorado by S.S. Papadopulos Associates. The data was analyzed in view of data from past studies undertaken by the County, specifically that conducted by URS in 2006. This report will describe the nature of the geochemical conditions of the study area, including the chemistry of the groundwater in the Wasatch Formation, influences of lithology on the water chemistry, any indications of the hydraulic relationship between the Wasatch and the underlying Mesa Verde Group, the orientation and extent of fractures and structural features, any potential influences on water chemistry from natural gas wells or gas development activities such as fracing and well construction, and potential influences from other anthropomorphic activities such as land cultivation.

Figure 1 shows the study area which is slightly larger than the Mamm Creek Field. The map also shows the mapped major structural features including shallow, intermediate and deep (basement) faults that can serve as vertical conduits for gas and fluid movement. There are likely additional faults and fractures not mapped as yet except by operators. The COGCC Mamm Creek Field Special Drilling Zone is also shown. This area was the subject of a Notice to Operators (NTO effective July 23, 2004) that established special drilling and completion procedures due to repeated reports of problems drilling and completing wells including lost circulation and pressure bumps during drilling, loss of cement during completion activities and persistent elevated bradenhead pressures.

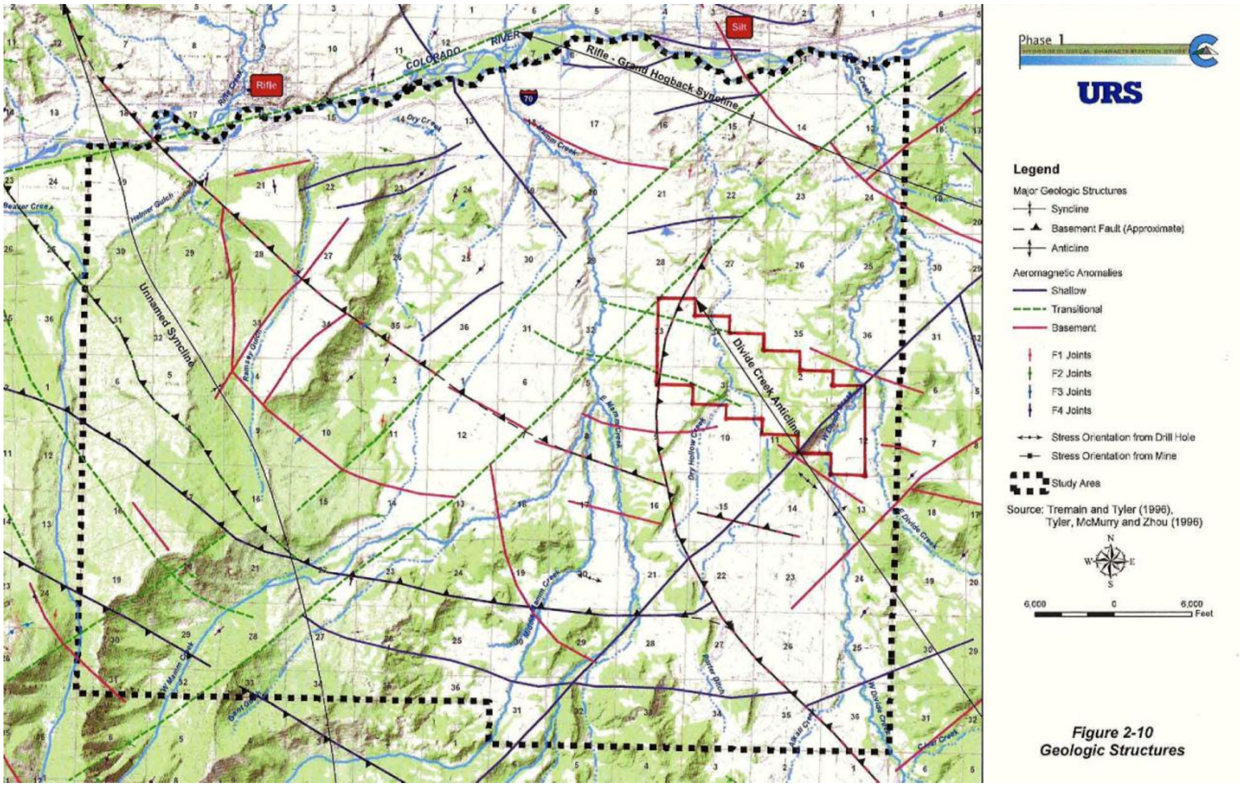

Figure 1. Phase I and II study area with major structural elements and COGCC special drilling zone outlined in red (from URS 2006).

Data Sources

The data sources used for this report include the Phase I study by URS Corporation, the Phase II study by S.S. Papadopulos and Associates, COGGC documentation and a Colorado School of Mines thesis by Tamee Albrecht entitled " Using sequential hydrochemical analyses to characterize water quality variability at Mamm Creek field area, Southeast Piceance Basin, Colorado". This produced a total of 704 samples from 292 locations including 18 samples from production (gas) wells, 46 samples from springs, 68 from streams, 26 from irrigation ditches and cisterns, 27 from ponds, 96 from monitoring wells at the West Divide Creek seep and 394 from domestic wells. Twenty-nine samples are currently unidentified as to location. The fundamental purposes of the first study were to establish the hydrologic and geologic framework in the study area, establish the pre-development baseline water quality, compile and evaluate post-development water quality data and identify impacts to water resources from petroleum activity. The Phase II study was focused on sampling of water wells that yielded elevated inorganic and organic parameters in Phase I, sampling of adjacent gas wells and sampling of water wells with elevated methane that lacked isotopic analyses (Papadopulos 2008).

Drilling and Production Activity

The COGCC database provides a record of the number of well and gas, oil and water production for the Mamm Creek Field. Figure 2 shows the increase in number of wells and produced fluids including gas. The number of wells in the last eight years has increased from about 200 to more than 1300 wells. During the last four years gas production has remained constant at approximately 80 million MCF/year with current plans to continue development based on ten acre well spacing, which would be about 7000 total wells. During this period the production of water from the gas-bearing interval has increased from 130,939 barrels to 2,513,980 barrels per year (5,499,438 to 105,587,160 gallons per year).

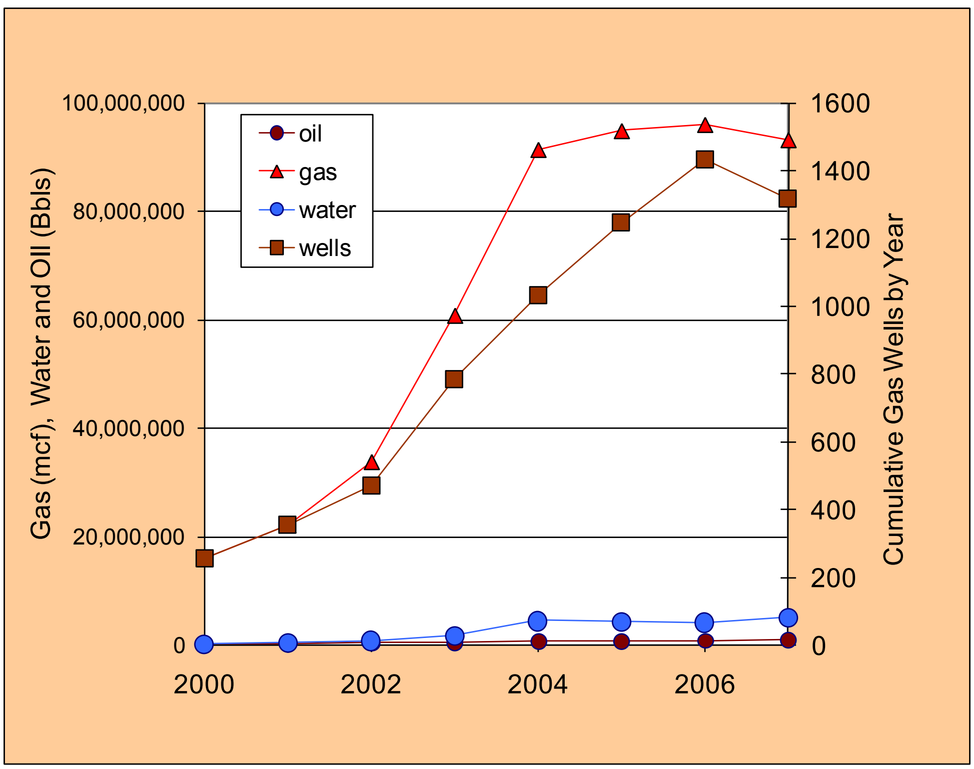

Figure 2. Number of wells and gas, oil and water production from the Mamm Creek Field for 2000 through 2007 (from COGCC website).

Bradendhead Pressures

One of measures used by COGCC to indicate well drilling problems is bradenhead pressure. In the Mamm Creek Field the regulations require wells to set and cement surface casing to below local water well intervals to protect the drinking water quality. This standard has variations in depth of cemented interval with some cases of as much as 800 feet of cemented surface casing with depths of 300- 800 feet more common. In addition the regulations require cementation of most wells to be cased and cemented to 500 feet above the top of gas. The top of gas is defined by geophysical well logs. The drill hole between the bottom of surface casing and top of gas casing in the Wasatch Formation is uncased. Typically this uncased length is 3000 to 6000 feet. Thus, the bradenhead casing collects any gas from leaks in the production tubing, cemented intervals and from gas discharge into the uncased interval. Figure 3 shows a schematic diagram of a well with bradenhead to help visualize the installation.

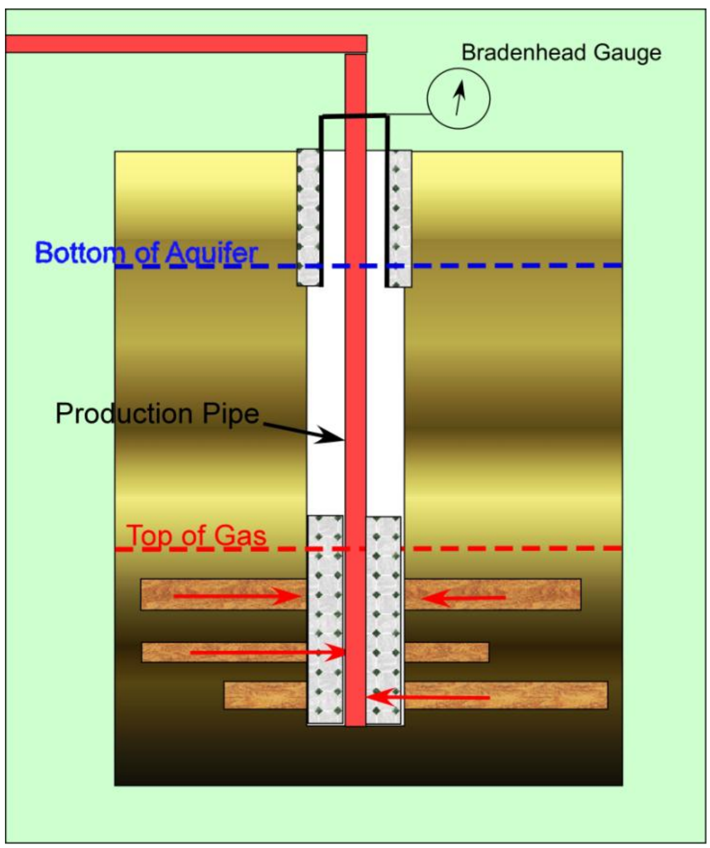

Figure 3. Schematic diagram of gas well completion and bradenhead, not to scale.

COGCC regulations require the initial bradenhead pressures be reported to the State, although only a limited number of well pressures were available for this analysis (Albrecht, 2007). The more stringent regulations for the Special Drilling Zone require repeated measurements to be reported. Normally, bradenhead pressures are elevated (100-800psi) for a month or two after completion of the wells as non-economic gas from the Wasatch Formation discharges into the well bore. The gas in the bradenhead is vented to atmosphere or collected for sale at the discretion of the operator. However, some well exhibit persistent elevated pressures (100-400 psi) that do not decline when vented or build back up on a monthly basis. These locations indicate horizontal and vertical gas, and potentially water mobility from the uncased interval in the Wasatch. Bradenhead pressure builds up in the well annulus either due to leaking gas from the well casing and production tubing, or infiltration of gas from uncased subsurface units. Wells with high or persistent bradenhead pressures generally indicating completion or cementation problems (URS, 2006), or sufficient production from the uncased intervals (Wasatch Formation).

Figure 4 shows the initial bradenhead pressure recorded. The distribution of these wells is related to the recognized geologic faults and fractures.

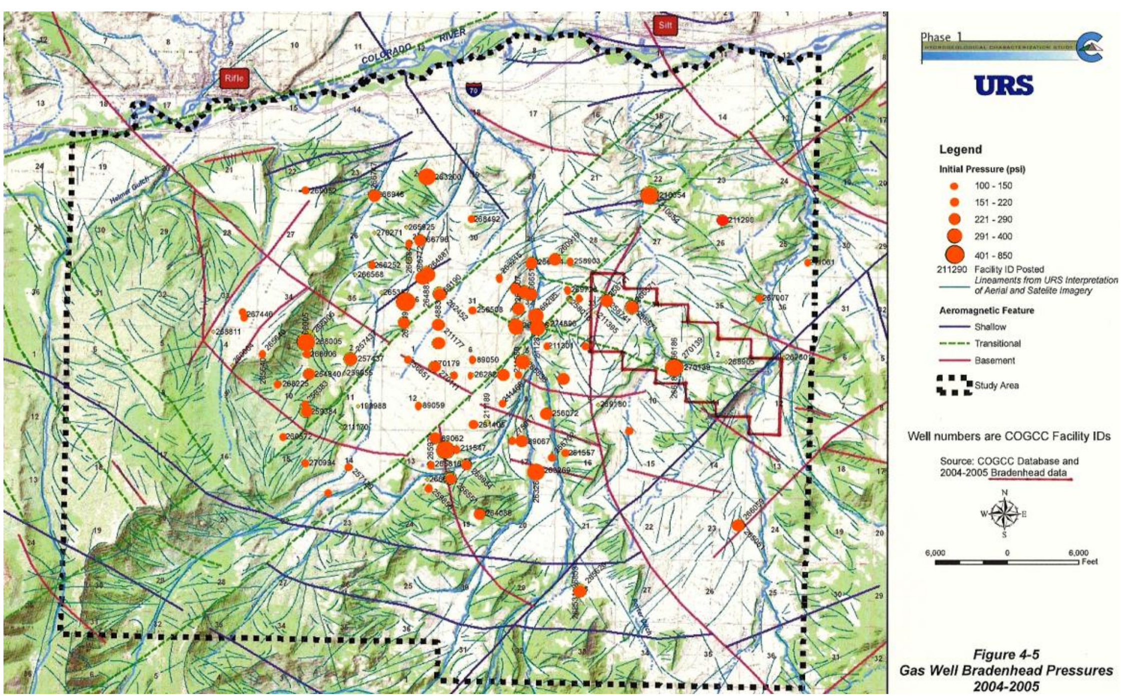

Figure 4. Map of distribution of reported initial bradenhead pressures of gas wells, mapped structural features and Mamm Creek Field Special Drilling Zone. Modified from URS (2006).

Persistent bradenhead pressures are indications of significant vertical mobility of gas. Figure 5 shows the location of wells identified as "problem wells" that exhibit persistent bradenhead pressures (>100 psi) that could not be lowered, or wells which regained pressures of at least 100 psi within 4 months of successful release. Most problem wells occur near the eastern portion of the study area coincident with the Divide Creek anticline. Increased fracturing near the anticline may cause a higher incidence of well drilling and completion problems, which in turn may affect water resources in this area by allowing introduction of gas or other fluids into the groundwater aquifer.

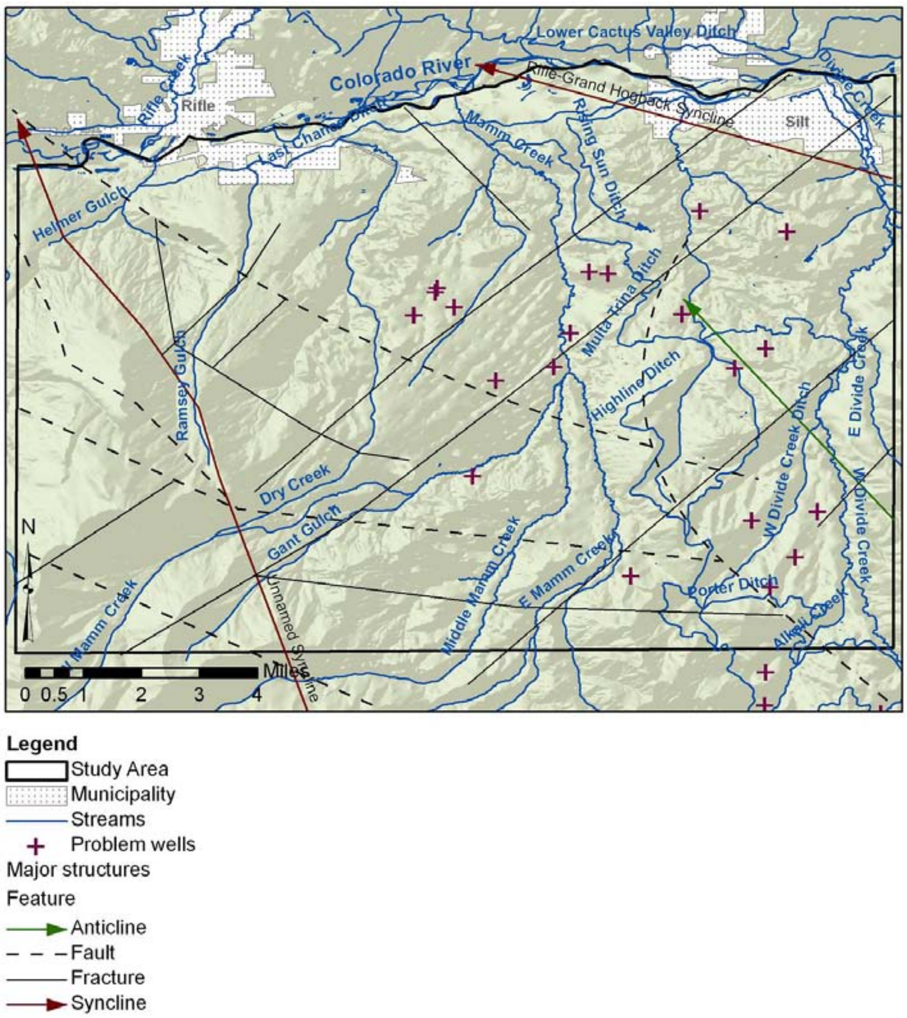

Figure 5. Location of gas wells with persistent or reoccurring bradenhead pressures greater than 100psi, from Albrecht (2007).

Distribution of Dissolved Methane

Pre-drilling methane values in water wells did not exceed 1ppm and were often much lower. Therefore, values above 1ppm dissolved methane are assumed to indicate impact to groundwater with the most likely source being produced gas from the Williams Fork Formation. There is also a trend of increasing dissolved methane with time that is positively correlated with the number of gas wells. Figure 6 and 7 show the increase in average methane with cumulative number of wells and the increase in samples with greater than 1ppm methane or more than 250ppm chloride (a major component of Williams Fork produced water) with time.

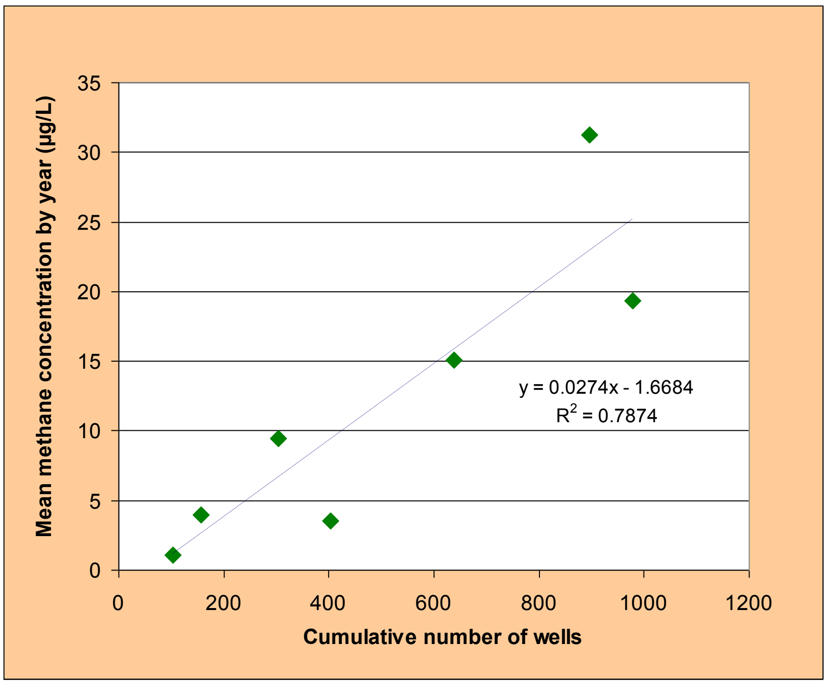

Figure 6. Average methane by year (2000-2007) versus cumulative number of gas wells in the Mamm Creek Field. R^2 is the squared correlation coefficient of determination for the linear regression. From Albrecht (2007).

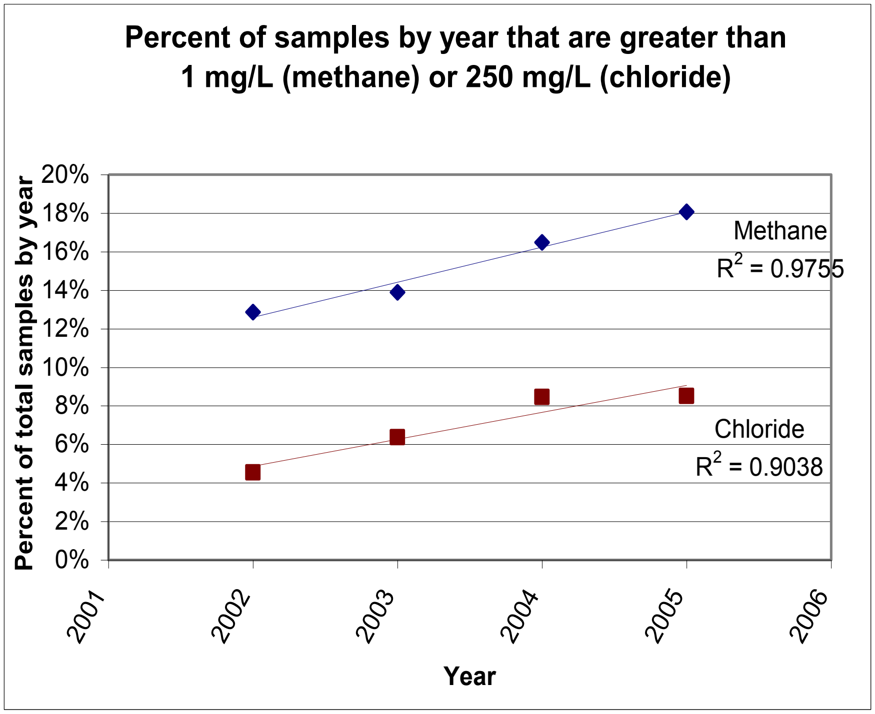

Figure 7. Percent of total sampled wells with methane >1ppm and chloride >250ppm by year for Mamm Creek Field. R^2 is the squared correlation coefficient of determination for the linear regression. From Albrecht (2007).

Methane Isotopic Data

SSPA sampled a total of seven domestic wells that had prior elevated methane content for isotopic analysis to determine the source of the methane. In all seven cases the isotopic values indicated thermogenic origin. As expected the gas from the four production wells show a tight cluster in the thermogenic field. Figure 8 is a plot of the stable isotopic values for hydrogen and carbon for 270 methane samples taken over the last four years, most from the West Divide Creek (WDC) seep.

It should be noted that all the groundwater samples except the WDC monitoring wells are taken from domestic wells. First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply.

The hydrogen and carbon isotopic values of methane are used to determine the origin of the gas (Schoell, 1980). Examination of the carbon and hydrogen isotopic values shows that there are three distinct clusters of samples with a few samples with intermediate values between the clusters. The first cluster is composed of most samples and plots in the thermogenic origin field. Samples in this group are from production well streams and bradenheads, as well as most of the SSPA domestic well samples. A smaller cluster of about 18 samples from the West Divide seep and surface ponds plots in the microbial fermentation field. Microbial fermentation is the process that occurs in many landfill, swamps and pond bottoms where natural accumulations of organic matter is converted into CO_2 and CH_4 in equal proportions. Methane produced by this process is often termed "swamp gas". The fermentation samples include many of the surface ponds as expected and a few samples from the WDC seep. The last cluster of samples consists of about 40 samples from a range of sources including the WDC seep and domestic wells that lie in the blue field in Figure 8, labeled microbial CO_2 reduction. Microbial CO_2-reduction is another process that produces methane wherein CO_2 is reduced to CH_4 by microbial processes (Botz et al., 1996). In this process the carbon isotopic value of the resulting methane becomes more negative than the parent CO_2 producing δD ratios between –250 and –170 per mil (Whiticar et al., 1986).

It is most likely that methane plotting in the microbial CO_2 reduction field is derived from the thermogenic CO_2 in the Williams Fork Formation and can be considered thermogenic. The Williams Fork Formation contains up to 22% by volume of CO_2 (Johnson and Rice, 1990) and this carbon dioxide is part of the normal production stream. The average value of 27 CO_2 samples from the Williams Fork Formation is –11.0 per mil (Albrecht, 2007). Methane produced by the CO_2-reduction of Williams Fork CO_2 gas would have a δ^{13}C value of –76.0 per mil (fractionation factor of approximately –65 per mil, Scott et al., 1994) similar to what is observed. Therefore, regardless if the CO_2-reduction process is occurring at depth in the Williams Fork Formation or in near surface environments, the original source of this methane is Williams Fork gas and all the samples that plot in the traditional thermogenic field and the microbial CO_2 reduction field are interpreted as indicating petroleum-related sources, not shallow natural methane.

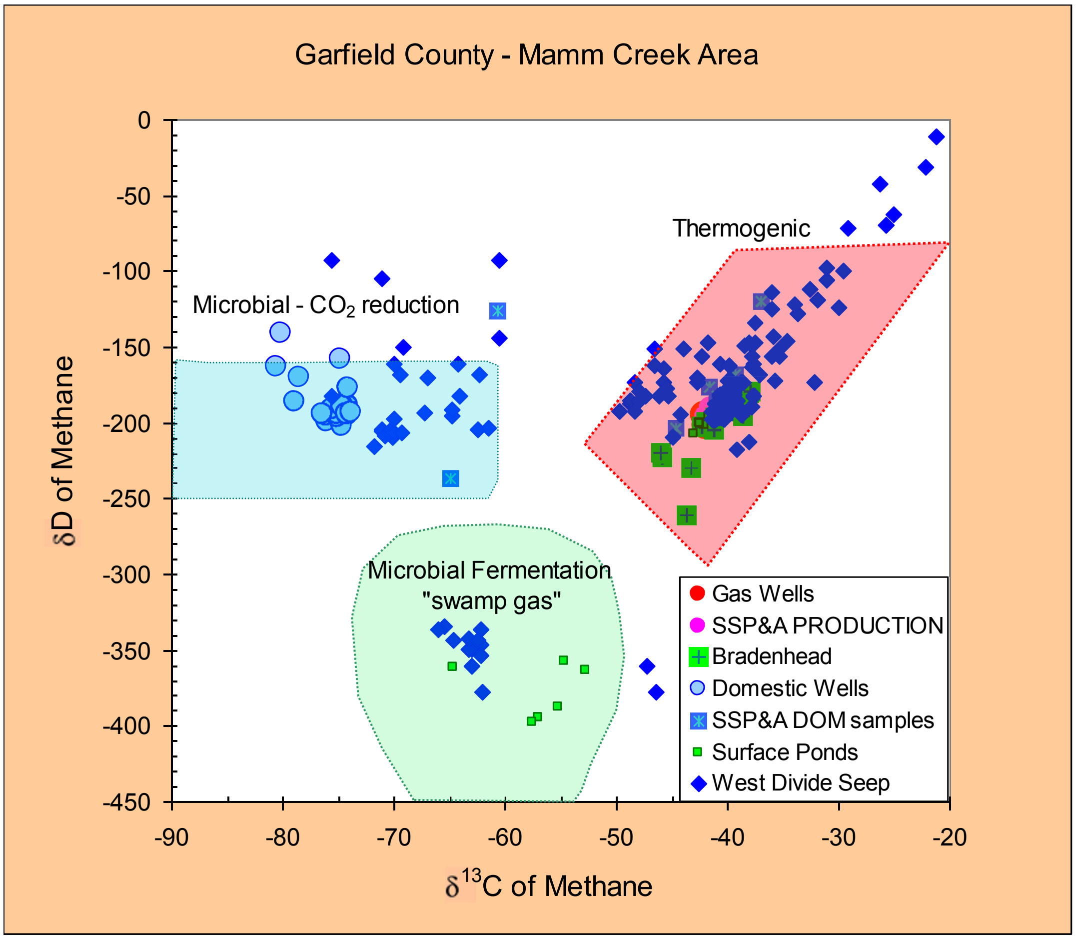

Figure 8. Plot of the carbon and hydrogen isotopic values for methane samples from a variety of sources in the Mamm Creek Field area.

An alternative interpretation for the theromogenic isotopic signatures is that the methane was originally fermentation gas and has been oxidized by microbial processes (CH_4 to CO_2) creating a "residual" methane that appears to be thermogenic (pg. 37, Papadopulos, 2007). In the oxidation process, the portion of the methane gas not converted to CO_2 becomes isotopically heavier as microbial processes selectively utilize the lighter isotope. However, the data in Figure 8 do not show any samples with intermediate values between the fermentation and thermogenic fields. Instead, the only samples with trends toward more positive values are found in the thermogenic and CO_2-reduction fields. Figure 9 is a plot of the isotopic composition of samples from the monitoring wells at the WDC seep with time. The figure shows that the isotopic composition of most samples remains constant during the eight month sampling period. However, there are three sample locations with thermogenic and one sample location with CO_2-reduction signatures that show a small trend of increase in more positive isotopic values indicating oxidation of methane, but this appears to be relatively rare. The current data do not support an interpretation of widespread "false positives" due to methane oxidation for the majority of the methane data.

The methane oxidation process also produces elevated dissolved bicarbonate (HCO_3^-), but none of the WDC seep samples show elevated bicarbonate. In conclusion, it appears that most of the methane samples from domestic wells, bradenheads and some surface ponds are thermogenic in origin, showing impact from produced Williams Fork gas on water resources. More conclusive evidence for the origin of the methane can be derived by measuring the carbon stable isotopic value of the dissolved bicarbonate from the same sample as the methane since each of the proposed sources for methane origin will generate bicarbonate with distinctly different values.

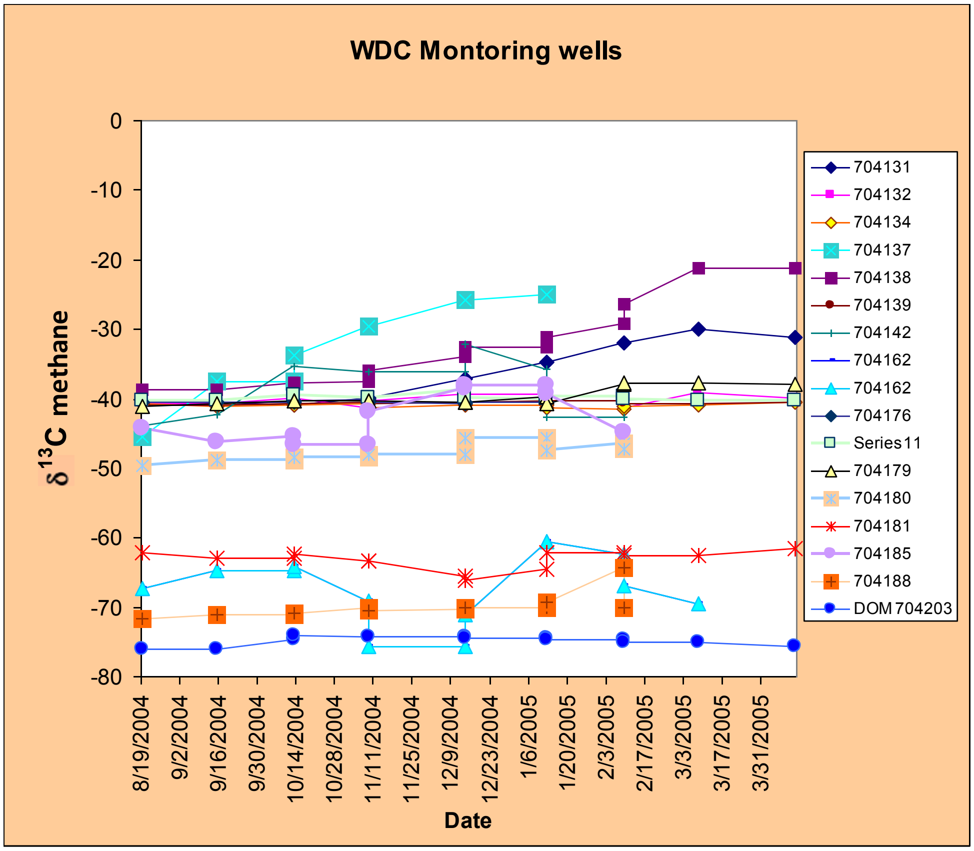

Figure 9. Plot of the carbon isotopic values for methane samples from the West Divide Creek seep versus time.

Water Quality

A total of 704 samples were analyzed for trends in water quality (chemistry). Figure 10 is a Piper plot of the samples showing the distribution of the major dissolved components and labeled by source in a manner analogous to the isotopic samples. The data show the majority of domestic wells and surface sources with low total dissolved solids (<1000ppm), while the gas well produced water samples have much higher total dissolved solids (TDS). There is a wide range of variation in the chemical composition of the samples.

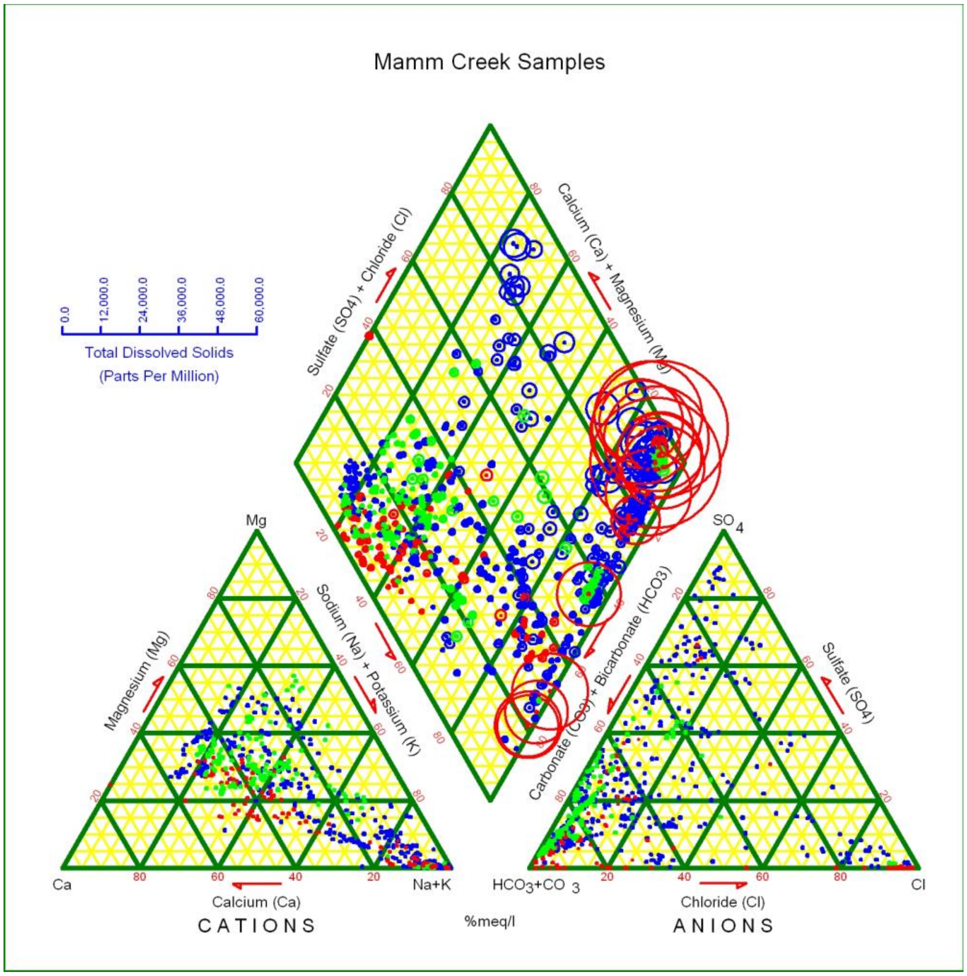

Figure 10. Piper diagram of 704 water samples from the Mamm Creek Field area, data from URS, 2006, Albrecht, 2007, and Papadopulos, 2008. Blue symbols are from domestic wells, red from gas wells and green from surface water samples. Size of circles in the diamond plot field indicates TDS value of sample.

Preliminary analysis of the water chemistry dataset shows the samples fall into three general categories: the first is low TDS, Ca-Na-Mg-HCO_3 water, the second is higher TDS Na-Ca-HCO_3-SO_4 water and the last is higher TDS with a distinctive Na-Cl component. The only source of Na-Cl in the study area is produced water from the Williams Fork Formation. Produced water is high salinity (up to 22,000ppm TDS), composed mostly of Na and Cl solutes. This distinctive water chemistry offers a natural tracer to evaluate the potential impact to groundwater quality. In the early stages of the development of the Mamm Creek Field the produced water was used to formulate drilling fluids for new wells. Since water production has exceeded drilling needs, the produced water is usually collected in unlined surface impoundments where it can re-infiltrate into the shallow aquifer, or is stored until treated and disposed. In 2007, 105,587,160 gallons of saline formation water was produced at the Mamm Creek Field.

Figure 11 shows the spatial distribution of the water chemistry in the study area. The size of the pie chart circle indicates the TDS, while the chemistry is shown by the distribution of the pie segments. Most of the samples have low TDS. The higher TDS samples are found in either the Special Drilling Area, especially near the nose of the Divide Creek Anticline, or near Grass Mesa. Comparison with Figure 1 shows the high TDS samples near Grass Mesa are associated with the intersection of mapped basement faults. These areas of intersecting deep faults are more likely to serve as hydraulic connections between the deeper formations and shallower aquifers.

Recognizing that elevated chloride content indicates the potential for produced water impact, statistical measures were employed in order to evaluate the potential effect. Figure 12 shows a cumulative frequency plot of chloride values. Cumulative frequency plots of specific solutes have been used to determine natural background in areas with anthropogenic impact. The breaks in slope of the curve represent a change in the population of samples. In this case the line shows a minor break at about 9ppm (about 30% of the total samples) and a sharper break at about 100ppm with a sharply increasing slope between 100 and 400ppm. All three groups of samples (<10, <100 and >400ppm) have a relatively unbiased mixture of sources (springs, ponds, and domestic wells). Since the domestic wells are not well constrained as to depth of sample, it is not possible to determine the relationship between chloride content and depth. The data is tentatively interpreted to indicate natural background for chloride is low (<10ppm), with a group of samples with moderate chloride (<100ppm) that are probably slightly impacted and a smaller set of samples (<20%) that have more significant impact (Cl > 400ppm). Figure 13 shows a plot of chloride versus TDS. The data show two distinct groups of samples, one with elevated chloride that lie along a mixing between normal groundwater and produced water and the other group where TDS and chloride are not related. The range of Cl and overall TDS in the samples from the gas wells has been interpreted brackish William's Fork Formation water (Papadapolus, 2007). However, it is likely the lower salinity samples represent dilution of saline formation water with condensed water formed during production-induced cooling. Future samples should be analyzed for silica content as well to quantify any potential dilution. This is a significant issue as accurate characterization of the Williams Fork Formation water will allow the degree of impact from produced water mixing with normal groundwater to be accurately calculated.

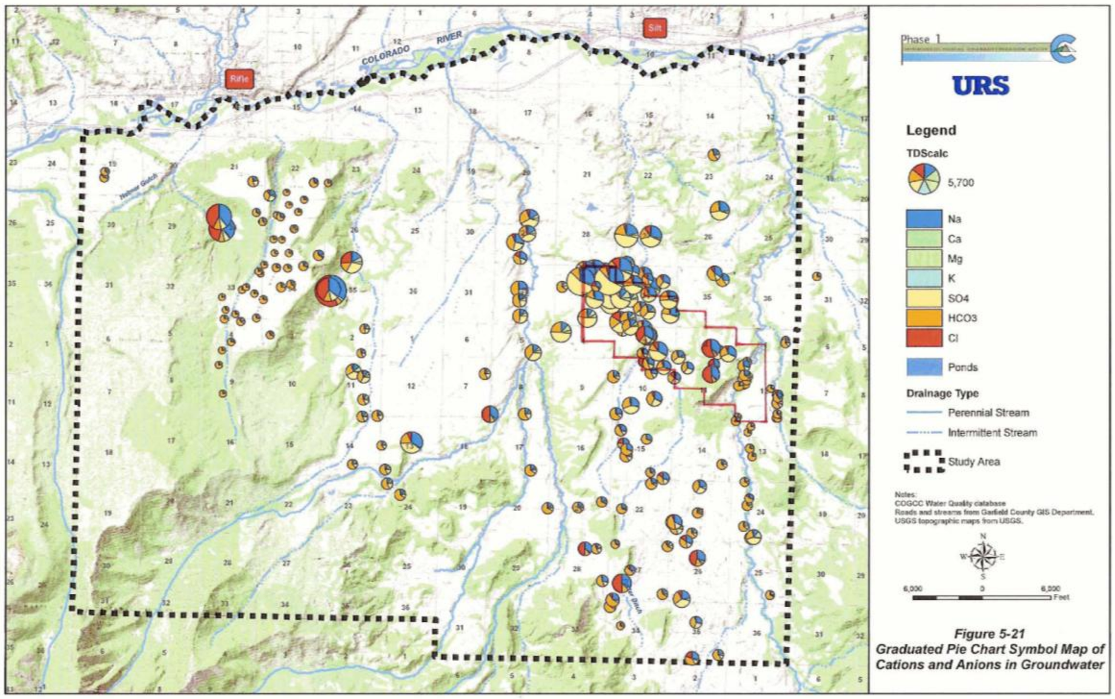

Figure 11. Map of groundwater quality using pie charts to show TDS and chemical composition of water samples from the Mamm Creek Field area (URS, 2006).

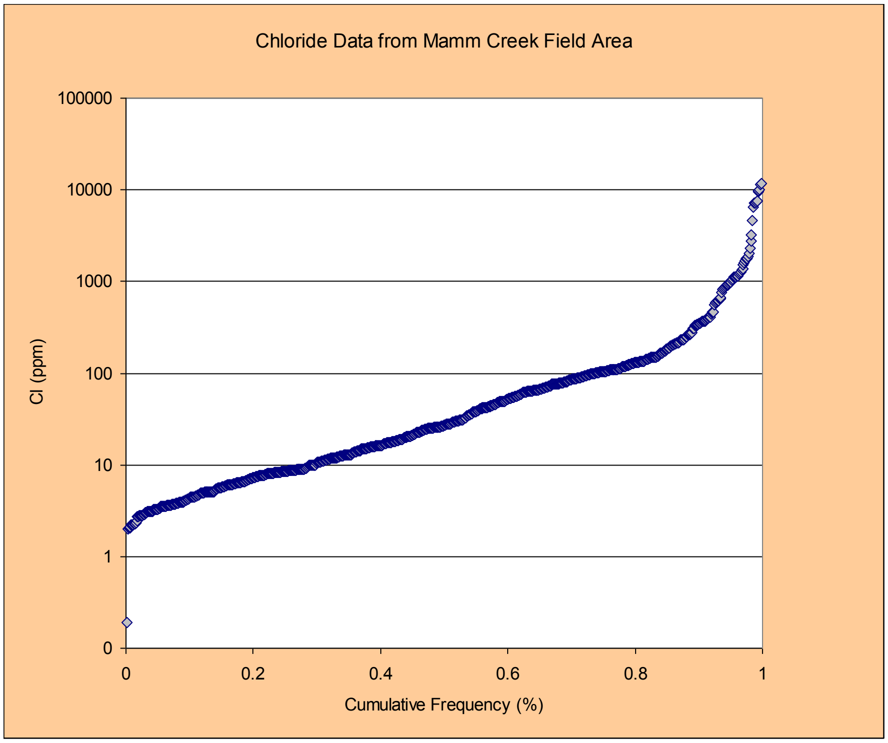

Figure 12. Cumulative frequency diagram for chloride content in water samples from the Mamm Creek Field area.

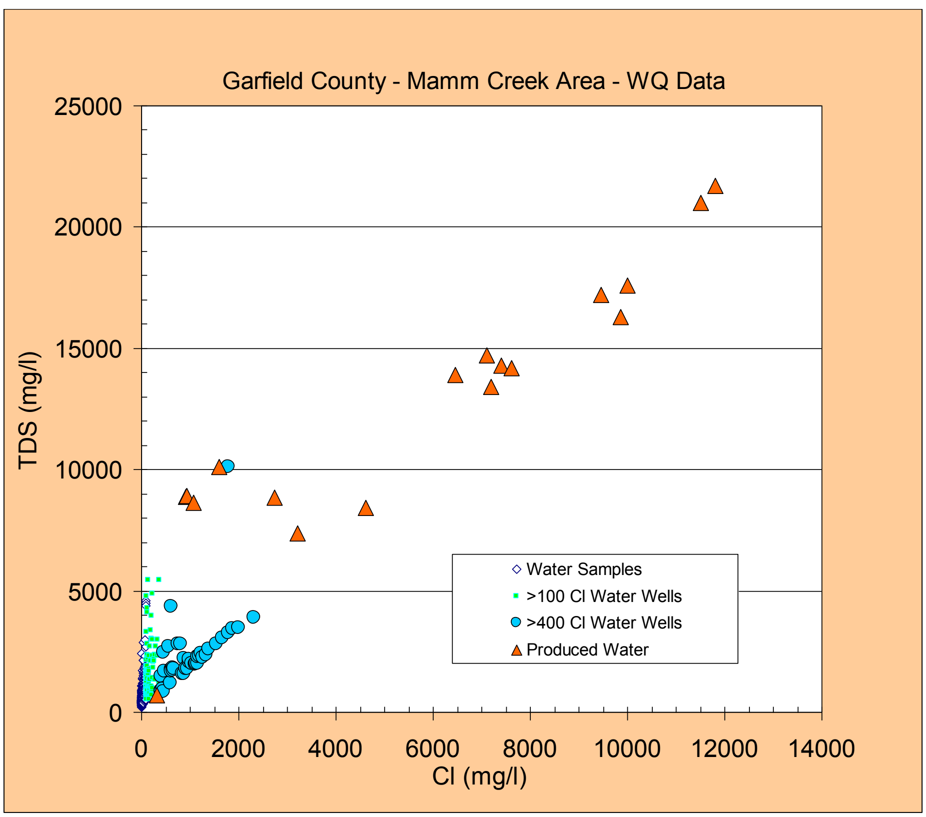

Figure 13. Plot of 704 surface and ground water samples from the Mamm Creek study area for chloride versus TDS.

A more rigorous statistical evaluation of the data was made using multivariate statistical methods using the data from the Phase I study by URS supplemented with additional water quality data from two surrounding areas without gas wells (Albrecht, 2007). The results of this study delineated two naturally-occurring water types, a low TDS Ca-Mg-HCO_3 water that occurs in streams and water wells near surface streams inside and outside the study area, and a higher Na-Ca-HCO_3-SO_4 water associated with water wells both inside and outside the study area that are either deeper or not near active discharge zones (streams). There were three other water types associated with groundwater samples from inside the study area that were impacted by petroleum activities. The first was associated with the WDC seep where low TDS background water had elevated methane, BTEX, Fe and Mn. The second impacted group of samples had higher TDS with elevated Na and Cl and methane. The third had high TDS and elevated Na, Cl and SO_4. Based on the spatial distribution of this water type and mixing models, samples from the third group were interpreted as being impacted by produced water. Figure 14 shows the spatial distribution of the statistically-derived clusters of water samples. The locations of the natural background and impacted samples locations are essentially the same as the Phase I URS map.

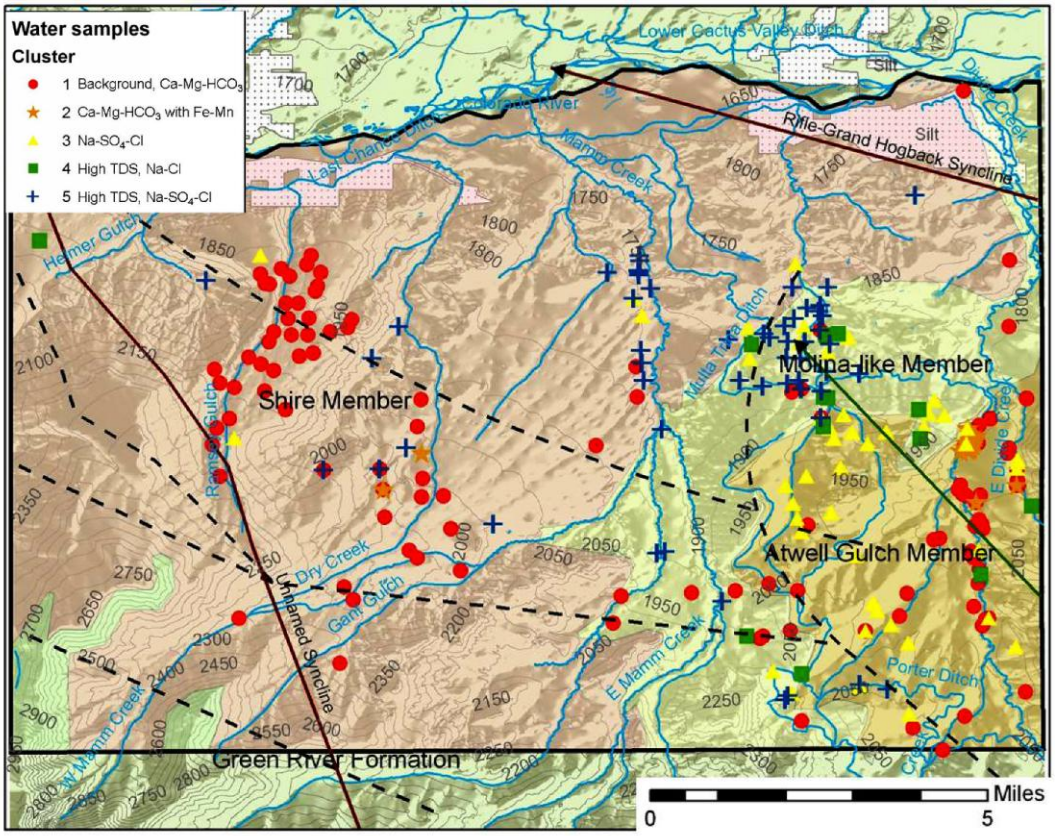

Figure 14. Map of locations of water samples divided into statistically-derived groups with three groups of samples showing impact from petroleum activities (modified from Albrecht, 2007).

Discussion

The Phase I and II reports noted the presence of some domestic wells with elevated concentrations of the inorganic components nitrate (NO_3), selenium (Se) and Fluoride (F). Domestic wells with elevated values (as defined by regulatory limits) were re-sampled during Phase II to confirm the elevated values and the well owners privately notified. None of these three inorganic contaminants appear related to petroleum activities at this time.

The issue of impact to water resources from petroleum activities can be viewed from two perspectives. One perspective is regulatory. In the case of regulatory action, the concentration of a regulated solute must exceed the standards for action to occur. This was the case in WDC seep for benzene, which allowed COGCC to take action. However, such situations have been rare in the study area. The other perspective is that of solutes in concentrations less than the regulatory limit, or solutes not regulated, but are above the natural background. The URS/SSPA data clearly provide evidence for solutes elevated above natural background in the study area. Currently, the trend of this sub-regulatory impact is best delineated by the increasing methane and chloride found in groundwater samples. The methane stable isotopic data show that almost all the samples are thermogenic in origin. While it is likely that some small amount of vertical migration of gas from the Wasatch Formation is naturally occurring, the low pre-drilling concentrations (<1ppm) and trend of increasing dissolved methane that is positively correlated to well numbers indicate that drilling and production activities are the cause. The locations of the most affected are near structural features where the faults and fractures maximize the vertical mobility of the gas, however it is not possible at this time to identify if leaking production tubing, leaking top-of-gas casing or un-cased Wasatch interval is the primary source of methane.

The trend and location of chloride, which is derived from Williams Fork production water shows similar trends of increasing concentration and locations near structural features. As was the case with methane the current data do not permit precise identification of the source. As with methane the total area impacted and identification of point sources is hindered by the low number of sample points (domestic water wells) compared to the number of potential point sources (gas wells).

Usually the identification of specific sources requires at least three monitoring points (wells) for each potential point source for determination of background and up-gradient water, and water down-gradient of potential sources. The Phase II report included an effort to identify gas wells as sources of impact by comparing samples from up-gradient gas wells adjacent to impacted domestic wells. The report concludes that samples from gas wells near two domestic wells with elevated methane (703996 and 704023) were not identical to the domestic well samples and therefore could not be positively identified as the source of the elevated methane. In both cases, the domestic well methane was depleted in ethane and propane. An additional five domestic wells with elevated methane had similar conditions. Finally, two more domestic wells with unusual water chemistry were ascribed to impact from sources other than the gas wells.

These conclusions highlight the difficulty of defining specific criteria for identifying gas well production impacts or assigning responsibility to specific gas wells. The case of the WDC is an excellent example of the difficulty. In that case the composition of gas at the seep was identical to the composition of the Swartz 2-15B well allowing positive identification. The site had over twenty monitoring wells in an area of 500 by 2000 feet, the amount of gas (>100 million cubic feet) was large, the leakage duration short (2 months) and the point source at the surface. These circumstances meant there was almost no degradation of the gas before sampling and the point source could be positively identified. Figure 15 shows the contours of methane concentration from the WDC seep December 2007 data.

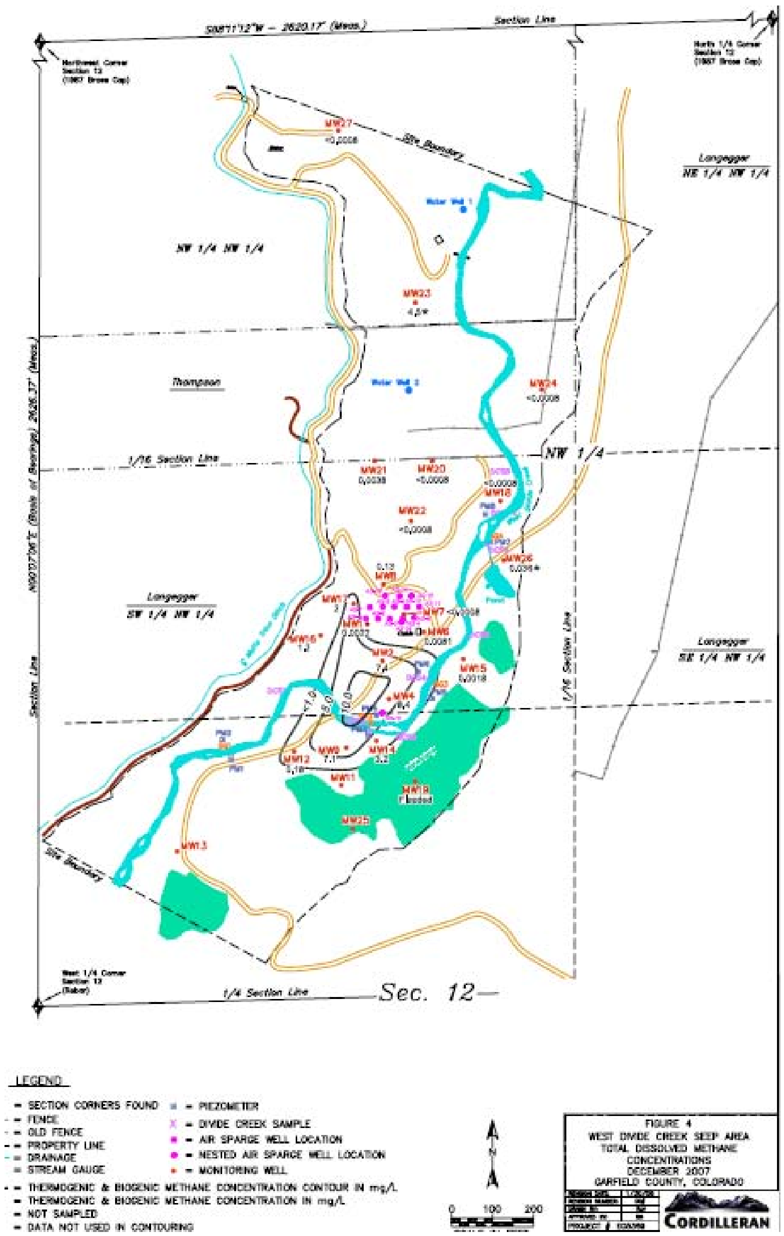

Figure 15. Contour of methane concentration from water samples at the West Divide Creek seep, from Cordilleran Compliance Service report, COGCC, 2008).

In contrast, the impact to domestic wells is likely to be from much smaller volumes of gas. The higher homologues (ethane, propane, butane) and other hydrocarbon components of the produced gas (i. e. BTEX) degrade rapidly during transport to by-products that are not analyzed in current sampling protocols after less than 400 feet transport (Albrecht, 2007). The WDC seep data (COGCC, West Divide Creek Seep Status, Dec. 2007) shows this pattern clearly as the monitoring wells 200-400 feet from the seep show no methane or BTEX as little as 200 feet from the point source. Samples from MW-12, only 200 feet from the seep, showed depleted ethane and propane. This means the current sampling and analysis program is unlikely to detect any but the largest volume leaks. Given the likely increase in number of gas wells and the inherent limitations of using domestic wells as monitoring wells, this inability to positively identify the point sources will continue.

Conclusions

The currently available water quality data is sufficient to establish the range of natural background water chemistry and delineate the impact of petroleum activities. Impacts from petroleum activity are not usually present at levels that exceed regulatory limits. The sub-regulatory impacts most clearly delineated are elevated methane and chloride in groundwater wells. There is a temporal trend of increasing methane in groundwater samples over the last seven years coincident with the increased number of gas wells installed in the study area. Pre-drilling values for methane in groundwater establish natural background was less than 1ppm, except in cases of biogenic methane that are confined to pond and stream bottoms. The cases of biogenic methane can be readily identified by stale isotopic values of the methane. The isotopic data for the methane samples show the most of the samples with elevated methane are thermogenic in origin. More conclusive identification of the origin of methane can be made by determination of the inorganic carbon isotopic value.

Concurrent with the increasing methane concentration there has been an increase in groundwater wells with elevated chloride that can be correlated to the number of gas wells. Chloride is derived from produced water. The increasing methane and chloride will not trigger regulatory action since there is no regulated limit on methane and the majority of chloride values are below regulatory limits, however, as more gas wells are drilled the chloride value may reach the regulatory limit.

Currently the only monitoring mechanism to evaluate the impact of gas well drilling and gas production to groundwater quality is the existing domestic water wells and surface water bodies. To date, there are only a few cases where COGCC has been able to identify wells as point sources. The number of water wells (<200) and their spatial distribution is inadequate to monitor and locate potential source of contamination from the more than 1400 potential point sources (gas wells and produced water pits). If future development continues the number of gas wells may reach 7000 assuming ten-acre spacing and the problem of determining sources will become more difficult.

Recommendations

The recommendations are based on the overview presented in this report and are directed to proactively manage the projected growth and continued operation of the tight gas resource. Based on the description of the scope of work were to be completed during the Phase II project, the most important shortcoming identified was the lack of specific locations, as either UTM or latitude-longitude, for nineteen reported chemical analyses from the 2007. The facility ID's for these samples are: 704151, 704158, 704228, 704320, 704327, 704392, 704423, 704434, 704444, 704545, 704660, 704475, 704477, 704479, 704500, 704501, 704516, 704526, and 704534. There should be locations on the well information form (Appendix A, Papadopulos, 2008).

In addition:

1. The County should secure GIS coverage of all water and gas wells, gas pipelines, produced water disposal pits and treatment facilities, mapped springs, streams and ponds that have been sampled or may be available for sampling. This GIS should be fully linked to a geodatabase that includes all chemical samples and can be updated as new information becomes available from basic monitoring activity by COGCC.
2. The County should design and contract the Phase III study to continue supplement basic monitoring activity by COGCC with targeted monitoring of sites with

increasing concentrations of parameters indicating impact. This Phase III study should ensure that the analyzed solutes are compatible with Phase I and II and not include parameters that are not common to both studies. This study should include a more rigorous examination of the limitations of domestic wells to identify leaking point sources (gas wells) and try and identify other methodologies. The WDC seep data may constitute a valuable source of information to delineate the extent and degree of impact from leaking gas wells and help define criteria for identifying impact of lower volumes and greater distance from other sources.

3. The County may wish to investigate regulatory guidelines and relevant examples of dealing with cumulative impacts to water quality in addition to traditional point source contamination that exceeds regulatory standards.

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