2 x 10^{-8} and the Three Monkeys Who Wrote SGEIS

Comparing the Michie Report and the GAO Report to Research Conducted by NTC, and ICF International In Support of the Revised Draft of the SGEIS

A White Paper: *By William C. Fischer*
Part 1

Can you recall the kindergarten fun of one child whispering something into the ear of the next child, then laughing at what comes out after five have had their turn? That seems to parallel how the following section came to be written into the revised draft of the SGEIS[1]:

> *6.1.6.1 Wellbore Failure*
> As described in Section 6.1.4.2, the probability of fracture fluids reaching an underground source of drinking water (USDW) from properly constructed wells due to subsequent failures in the casing or casing cement due to corrosion is estimated at less than 2 x 10^{-8} (fewer than 1 in 50 million wells). Hydraulic fracturing is not known to cause wellbore failure in properly constructed wells.

[1] Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

This isn't kindergarten, and the outcome won't be funny. Where could such a number have come from? It appears in several non peer-reviewed industry reports written by J. Daniel Arthur of ALL Consulting, Tulsa, Oklahoma in which he consistently references the **2×10^{-8}** number to a 1989 paper by Michie and Associates. The Michie report calculated a hypothetical risk based on data from 19 of 50 oil and gas basins in the U.S., by using a computer model to estimate the probability that an undetected and simultaneous, three mode casing failure would occur in a Class II waste water injection well in an oil field in the Williston basin, a geologic formation in North Dakota.

How is this information relevant to assessing the probability that an underground source of drinking water (USDW) in New York will be contaminated by the High Volume Slick Water Hydraulic Fracturing (HVHF) process used to complete a natural gas well drilled into in the Marcellus formation? After earning $ 433,833.24 in research and consulting fees, the experts seem to have missed how these two scenarios might differ. How could New York authorities accept such a number as applicable to HVHF contamination when, as this very research was being conducted for New York's DEC, John Hanger, the Secretary of the Pennsylvania's DEP, publicly announced in a Dimock church that Cabot Oil and Gas had contaminated[2] the ground water around 18 of 63 wells drilled in Susquehanna County, Pennsylvania? How could the experts have also dismissed a July 5th, 1989 Report by the United States General Accounting Office, titled ***Drinking water: safeguards are not preventing contamination from injected oil and gas wastes***?

I. The Science

Governor Andrew Cuomo has stated that a decision on hydrofracking should be based "on the facts and on the science." The scientific method has four steps:

1. Observation and description of a phenomenon. [contamination of USDW's near HVHF operations]
2. Formulation of a hypothesis to explain the phenomenon.
3. Use of the hypothesis to predict the existence of other phenomena. [Radioactive contamination, increased health risks, adverse effects to indigenous flora and fauna, etc.]
4. Performance of experimental tests of the predictions by several independent experimenters and properly performed experiments. [NOT DONE]

One of the most critical hypotheses to be tested can be stated as:

> ***Under a regulatory regime that enforces best management practices, HVHF will not contaminate USDWs.***

[2] http://www.youtube.com/watch?v=oCIX4Bbt0Po

A literature search may identify variables that can affect an experiment, but it is not a substitute for empirical research. The relevance of empirical testing is dependent upon the attributes of reliability and validity. Reliability is the repeatability of results from similar tests. Validity is the appropriateness of the method used to test the variables. For example, a thermometer is used to test for heat, a spring to test for resistance. After data have been collected, statistical inquiry using computer modeling may assist in projecting the risk of an unwanted outcome [such as groundwater contamination], but only if the data are both reliable and valid.

II. The Consulting Contracts

With the advent of the HVHV technology, New York's existing 1992 Oil, Gas, and Solutions Mining GEIS had to be updated. The New York State Energy Research and Development Authority (NYSERDA) subcontracted this work:

Contractor	amount	Date let	Completed
ICF International	$88,263.00	3/15/2007	12/10/2009
URS Corporationm	$87,488.38	3/25/2009	6/28/2011
Alpha Environmental Inc	$59,995.24	3/25/2009	12/4/2009
Nagle, Tatich, Cranston, LLC	$48,321.00	3/25/2009	11/3/2009
Geological Consulting Services	$74,820.87	3/31/2010	in process
Socioeconomic Consulting Services	$24,999.20	3/30/2010	2/9/2011
Sammons/Dutton	$49,995.55	3/31/2010	6/17/2011
Total	$433,883.24		

Under contract #9679, ICF International was tasked with researching eleven items, the second of which was "researching the subsurface mobility of fracturing fluids and additives".

Under contract # 11170, NTC Consultants was tasked with researching two items: (1) "an assessment [of] adverse cumulative impacts with respect to noise, visual effects, air quality and water resources"; and (2) "An assessment of the impact of drilling on community character.

III. The Foundation Document

In April 2009, a report was prepared by ALL Consulting of Tulsa, OK, and the Ground Water Protection Council of Oklahoma City, OK, for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory, under contract DE-FG26-04NT15455. The document is titled, ***Modern Shale Gas Development in the United States: A Primer.*** Its principal author is J. Daniel Arthur of All Consulting. Direct quotes or modified versions from the text form the basis of numerous other industry papers. It is a foundational document for the oil and gas industry's mantra that HVHF is a safe and proven technology.

J. Daniel Arthur

As will be demonstrated, the significance of this document cannot be overstated as to its eventual influence on the final draft version of the New York State SGEIS. Therefore a critical review of the assertions and conclusions made by Mr. Arthur are in order. Both of the reports prepared by NTC and ICF International for NYSERDA relied upon the doctrines promoted in Mr. Arthur's report, and each used it as a blueprint for their own interpretations of what it meant. It was by the reiterative process of using the NTC and ICF reports that the SGEIS took final form.

Each of J. Daniel Arthur's numerous documents on this topic quote the $2X10^{-8}$ number and each references it back to a back to a 1989 American Petroleum Institute paper prepared for Underground Injection Practices Council Research Foundation by Michie & Associates, titled "***Evaluation of Injection Well Risk Management Potential in the Williston Basin".***

So here is the path: The original document by Mitchie is (mis)quoted and interpreted by Arthur, who writes the *Primer* which is quoted and used by NTC and ICF as the foundation for their reports to NYSERDA, which in turn, formed the basis of the final text incorporated into the SGEIS.

III. <u>The relevant passage from the 'PRIMER"</u>

Let's examine the relevant passage from J. Daniel Arthur's *Primer* containing the $2x10^{-8}$ number and then compare it to the original Mitchie document. The following is quoted verbatim from page 53 of the *Primer*: [Note that while the footnote sources are also quoted, the original paper's footnote numbers follow as subscripts to the footnote numbers used herein].

> "Detailed analysis was performed for those basins in which there was a possibility of casing corrosion[3]257. Risk probability analysis provided an upper bound for the probability of the fracturing fluids reaching an underground source of drinking water. Based on the values calculated, a modern horizontal well completion in which 100% of the USDWs are protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the probability that fluids injected at depth could impact a USDW would be between 2 x 10^{-5} (one well in 200,000) and 2 x 10^{-8} (one well in 200,000,000) if these wells were operated as injection wells. Other studies in the Williston basin found that the upper bound probability of injection water escaping the wellbore and reaching an underground source of drinking water is seven changes (SIC)

[3] 257 Michie & Associates. 1988. Oil and Gas Water Injection Well Corrosion. Prepared for the American Petroleum Institute.
1988.

in one million well-years where surface casings cover the drinking water aquifers[4]258.

These values do not account for the differences between the operation of a shale gas well and the operation of an injection well. An injection well is constantly injecting fluid under pressure and thus raises the pressure of the receiving aquifer, increasing the chance of a leak or well failure. A production well is reducing the pressure in the producing zone by giving the gas and associated fluid a way out, making it less likely that they will try to find an alternative path that could contaminate a fresh water zone. Furthermore, a producing gas well would be less likely to experience a casing leak because it is operated at a reduced pressure compared to an injection well.

It would be exposed to lesser volumes of potentially corrosive water flowing through the production tubing, and it would only be exposed to the pumping of fluids into the well during fracture stimulations.

The API study included an analysis of wells that had been in operation for many years when the study was performed in the late 1980s, and does not account for advances that have occurred in equipment and applied technologies and changes to the regulations. As such, a calculation of the probability of any fluids, including hydraulic fracture fluids, reaching a USDW from a gas well would indicate an even lower probability; perhaps by as much as two to three orders of magnitude. The API report came to another important conclusion relative to the probability of the contamination of a USDW when it stated that:

> …for injected water to reach a USDW in the 19 identified basins of concern, a number of independent events must occur at the same time and go *undetected*[emphasis added]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing,] and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a USDW[5]259.

As indicated by the analysis conducted by API and others, the potential for groundwater to be impacted by injection is low. It is expected that the probability for treatable groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed, deep shale gas wells when a high level of monitoring is being performed would be even less than the 2×10^{-8} estimated by API."

[4] 258 Michie, T.W., and C.A. Koch. *Evaluation Of Injection-Well Risk Management In The Williston Basin*, June, 1991.
[5] 259 Michie & Associates. 1988. *Oil and Gas Water Injection Well Corrosion.* Prepared for the American Petroleum Institute.
1988.

IV. The MICHIE REPORT

The actual text of Mitchie's *Oil and Gas Water Injection Well Corrosion* document states something quite different:

> **"upper bounds for contamination were found to be on the order of 10^{-6} potential contamination events per well-year where surface casings covered USDWs and 10^{-3} where surface casings did not."**

Assume for the moment that during transcription, scanning or copying, an error was made in which 10^{-6} was misconstrued as 10^{-8}. Admittedly this is conjecture, but it would account for the magnitude of the absolute number, which is 100 times smaller than the value estimated by Mitchie.

What is not accounted for is the missing denominator in the fraction stated by Mitchie as "potential contamination events ***per well-year***". In a fraction, the denominator represents the number of equal parts that make up the whole. And 'per' means 'divide by', as in miles per hour. Whenever the $2x10^{-8}$ number appears in the many papers authored by Arthur, the denominator of '*per well-year'* has simply been dropped.

So, the $2x10^{-8}$ number becomes a dimensionless coefficient – it is meaningless! The unit "per well-year"' can no more be construed as "per well" than "miles per hour" [speed] can be construed as "per mile"[distance]. If the life of an injection well were 25 years, the resulting projections by Arthur would be skewed by another factor of 25.

Not mentioned in J. Daniel Arthur's passage quoting Mitchie as the source of the $2x10^{-8}$ number, is that the Mitchie went on to state:

> **"For example, the Permian Basin, which is characterized as having significant potential for external casing corrosion, has 25,000 water injection wells which accounted for 29 percent of the water injected in the U.S. The upper bound number of wells potentially leaking to a USDW in the Permian Basin in one year is 0.07, assuming 100 percent of the wells have surface casing covering the USDWs."**

Let's do the math: 25,000 x 0.07 =**1,750 wells leaking PER YEAR!**

While acknowledging that it is invalid to compare apples to oranges or the failure rate of injection well casings in the Permian Basin to production well casings in the Marcellus, the 1,750 well leaks PER YEAR estimated by Mitchie in a field of 25,000 wells, begins to reflect the reality of what is being experienced in Pennsylvania. Now we need to know the relative potential for corrosion in the Apalachian Basin vs. the Permian Basin, a matter disclosed in a 1993 report by ICF International.

V. Comparing Arthur's 'Primer' to Mitchie and Associates

• Mitchie did not –as stated by Arthur – calculate "the probability of ***the fracturing fluids*** reaching an underground source of drinking water". Mitchie analyzed the risk of corrosion in injection wells from being filled with brine wastes recovered from oil and gas wells.

• The two numbers that appear in Arthur's *Primer* using the scientific notation format, 2×10^{-5} (one in 200,000) and 2×10^{-8} (one in 200,000,000) are both misstated. Scientific notation is used as a shorthand method to handle very large or very small numbers. The numbers are written in the form of ($a \times 10^{b}$). So 2×10^{-5} would be written as 0.00002, the reciprocal of which is 50,000 or one in fifty thousand – not as stated by Arthur, as one in two hundred thousand. Likewise, 2×10^{-8} would be written as 0.00000002 or one in fifty million – not as stated by Arthur, one in two hundred million. These are 400% errors.

• These errors along with the previously described absence of the denominator "*per well-year*" may reasonably raise issue with the credibility of the author as a scientific authority, and an indication that the *Primer* report was not subjected to peer review.

• With the inclusion of the phrase "a modern horizontal well completion", Mr. Arthur appears to have now confabulated the 2×10^{-8} risk number from injection wells to a single horizontal production well.

• Without any verifiable data, equation or calculation being written, the *Primer* offers the opinion, that: "As such, a calculation of the probability of any fluids, including hydraulic fracture fluids, reaching a USDW from a gas well would indicate an even lower probability; perhaps by as much as two to three orders of magnitude." Again, this opinion confabulates injection wells with a production well. Nor is it stated that such a calculation was actually done. Whether the opinion is based on surmise, conjecture or intuition is unclear.

• The three orders of magnitude opined by Arthur would take 2×10^{-8} to 2×10^{-11}. When compared with the 10^{-6} potential contamination events *per well-year* for wells with casings, estimated in the Michie paper, the difference is now five orders of magnitude, or a factor of one hundred thousand.

VI. **Fracking Pressure vs. Production Pressure**

The *Primer* states that:" A production well is reducing the pressure in the producing zone….." Left unstated is the fact that while pressure does indeed reduce during the production phase, during the fracturing phase the hydraulic pressure in pounds per square inch must be equal to the overburden pressure plus enough pressure to fracture the shale, a pressure greater than that which is allowed in a disposal well of the same depth.

There follows an insidious inference that somehow, because of the depths involved, the migration of subsurface fluids would take eons to move through numerous layers of rock acting as impervious caps. In some areas, that may be true, absent wellbores, fractures and faults. But what should be evaluated here is a process of hydraulic fracturing fluids moving through thousands of wellbores, both those being drilled and those that have been abandoned and left uncapped. The brakes on your car work on the same hydraulic fluid principle, and you expect them to work instantly. And they do, when there are no gaps in the fluid path, either brake line or wellbore.

As stated, during the fracturing phase [generally between 40 and 100 hours], the hydraulic pressure in pounds per square inch must be equal to the overburden pressure plus enough pressure to fracture the shale. Nowhere in their extensive reports to NYSERDA do the consultants explicitly calculate the pressure necessary to push fluids back toward the surface. So, let's do that here.

> Water at zero degrees Centigrade or 32 degrees Fahrenheit has a specific density of 999.8395 kg/m^3 or 62.41794 lbs/ft^3. Convert the units to 0.43346 $lbs/in^2/ft$. That means for each vertical foot of water in a pipe, the pressure increases by 0.43346 lbs/in^2. In a wellbore drilled down to one mile below the surface and filled with water, the pressure at the bottom will be (5,280 ft)*(0.44346 $lbs/in^2/ft$) = 2,288 lbs/in^2. Any pressure at the bottom hole in excess of 2,288 $lbs./in^2$ will push the fluid back up. Add to this value the pressure necessary to fracture the shale and fluids will have sufficient pressure to travel back up toward the surface, either inside or outside the casing if a flow path is available. That is why the contaminated brine waste is called "flowback".

VII. **Comparing Arthur's *Primer* to the SGEIS**

It now becomes apparent that the doctrines proselytized by J. D. Arthur in the All Consulting documents, are quoted nearly verbatim in Section 6.1.4.2 of the SGEIS, on Page 6-41.

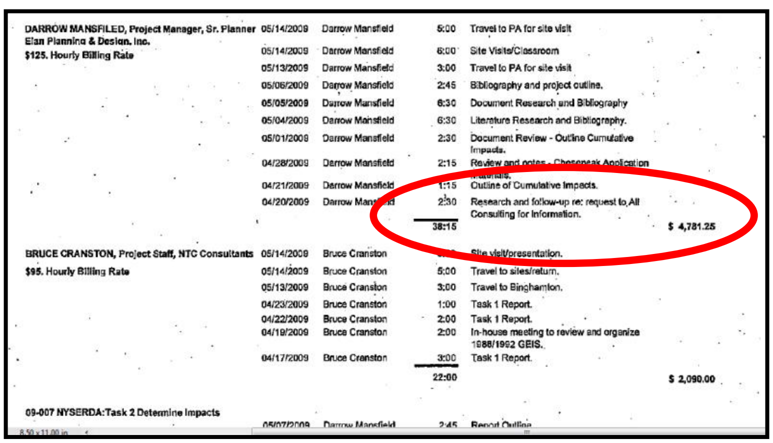
6.1.4.2 Fluids Pumped Into the Well

Fluids for hydraulic fracturing are pumped into the wellbore for a short period of time per fracturing stage, until the rock fractures and the proppant has been placed. For each horizontal well the total pumping time is generally between 40 and 100 hours. ICF International, under its contract with NYSERDA to conduct research in support of SGEIS preparation, provided the following discussion and analysis with respect to the likelihood of groundwater contamination by fluids pumped into a wellbore for hydraulic fracturing .

In the 1980s, the American Petroleum Institute (API) analyzed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Although the API did not address the risks for production wells, production wells would be expected to have a lower risk of groundwater contamination due to casing leakage. Unlike Class II injection wells which operate under sustained or frequent positive pressure, a hydraulically fractured production well experiences pressures below the formation pressure except for the short time when fracturing occurs. During production, the wellbore pressure would be less than the formation pressure in order for formation fluids or gas to flow to the well. Using the API analysis as an upper bound for the risk associated with the injection of hydraulic fracturing fluids, the probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than 2 x 10^{-8} (fewer than 1 in 50 million wells).

VIII. Multiple NYSERDAContractors Defer to Arthur's ALL Consulting

This is a snapshot from a timesheet submitted to NYSERDA under contract # 11170 by Lisa Nagle, a principal of NTC Consulting ;



DARROW MANSFILED, Project Manager, Sr. Planner Elan Planning & Design, Inc. $125. Hourly Billing Rate	05/14/2009	Darrow Mansfield	5:00	Travel to PA for site visit	
	05/14/2009	Darrow Mansfield	6:00	Site Visits/Classroom	
	05/13/2009	Darrow Mansfield	3:00	Travel to PA for site visit	
	05/06/2009	Darrow Mansfield	2:45	Bibliography and project outline.	
	05/05/2009	Darrow Mansfield	6:30	Document Research and Bibliography	
	05/04/2009	Darrow Mansfield	6:30	Literature Research and Bibliography.	
	05/01/2009	Darrow Mansfield	2:30	Document Review - Outline Cumulative Impacts.	
	04/28/2009	Darrow Mansfield	2:15	Review and notes - Chesapeak Application Materials.	
	04/21/2009	Darrow Mansfield	1:15	Outline of Cumulative Impacts.	
	04/20/2009	Darrow Mansfield	2:30	Research and follow-up re: request to All Consulting for Information.	
			38:15		$ 4,781.25
BRUCE CRANSTON, Project Staff, NTC Consultants $95. Hourly Billing Rate	05/14/2009	Bruce Cranston	[illegible]	Site visit/presentation.	
	05/14/2009	Bruce Cranston	5:00	Travel to sites/return.	
	05/13/2009	Bruce Cranston	3:00	Travel to Binghamton.	
	04/23/2009	Bruce Cranston	1:00	Task 1 Report.	
	04/22/2009	Bruce Cranston	2:00	Task 1 Report.	
	04/19/2009	Bruce Cranston	2:00	In-house meeting to review and organize 1988/1992 GEIS.	
	04/17/2009	Bruce Cranston	3:00	Task 1 Report.	
			22:00		$ 2,090.00
09-007 NYSERDA:Task 2 Determine Impacts					
	05/07/2009	Darrow Mansfield	2:45	Report Outline	

It shows that Darrow Mansfield, a project manager and senior planner for Elan Planning and Design Inc. charged NTC for 2.5 hours at $125/hr or $312.50 for "Research and follow-up re: request to ALL Consulting for information."

Darrow Mansfield

Recall that under contract # 11170, NTC Consultants was tasked with researching adverse cumulative impacts of noise, visual, air and water resources, and an assessment of the impact of drilling on community character.

So who is Darrow Mansfield? From September of 2008 to August of 2009 he was employed as Sr. Planner by Elan Planning and Design. He is now President at Mansfield Custom Homes, LLC in the Burlington, Vermont area. He earned a Bachelor of Science degree in Environmental Studies and Planning with an emphasis on Land Use and Natural Resources. Mr. Mansfield has so far declined to respond to email and written inquiries with regard to his communication with All Consulting.

How does Elan Planning and Design figure in to the writing of the SGEIS? Elan Planning, Design is a landscape architecture firm created by Lisa Nagle, AICP and Jere Tatich. Elan is described as "affiliated" with Nagle, Tatich, Cranston, LLC, d/b/a NTC Consultants located in Saratoga Springs, NY. NTC is a Certified NYS Disadvantaged Business Enterprise, a Certified NYS Woman-Owned Business Enterprise, and an Economically Disadvantaged Woman–Owned Small Business Enterprise .

Lisa Nagle

Ms. Nagle was Mr. Mansfield's employer. She has also declined to respond to email and written inquiries with regard to both her and Mr. Mansfield's communications with All Consulting. As neither Mr. Mansfield nor Ms. Nagle would respond to these inquiries, on 2/15/12 a separate inquiry was sent by email to J. Daniel Arthur advising him of the charges submitted by NTC for information from ALL Consulting and asking whether he had spoken with any of the six companies contracted by NYSERDA.

His response: "We are not a subcontractor to ICF or NTC as part of the SGEIS effort. Honestly, I don't recall anyone from NTC ever contacting us_"
Dan Arthur
ALL Consulting

As ICF International was specifically tasked with "researching the subsurface mobility of fracturing fluids and additives" a similar inquiry was sent to Steven Anderson, Public Affairs Director, ICF International, Fairfax, VA attempting to determine if any ICF employees had supplied that $2x10^{-8}$

number to the SGEIS. Invoices submitted by ICF included the names of Howard Chang, Brian Gillis, Ralph Grismala, Edward Hauswald, Robert Hegner, Donald Robinson, Julianne Sammul, and Melisa Zgola. Mr. Hauswald is a private consultant.[6] To date, ICF International has also declined to respond.

IX. The GAO Report

On July 5th, of 1989, the same year as the API sponsored report by Michie, a report of drastically different conclusions was delivered to the Chairman of the Environment, Energy and Natural Resources Subcommittee, of the United States General Accounting Office. That document # B-227690, is titled: ***Drinking water: safeguards are not preventing contamination from injected oil and gas wastes.*** The following excerpted paragraphs were written therein:

> Page 2: Background: Brines from Class II wells can enter drinking water supplies directly, through cracks and leaks in the well casing, or indirectly through nearby wells, such as those used for oil and gas production, that have ceased operating.
>
> Page 3: Results in brief: Although the full extent is unknown EPA is aware of 23 cases nationwide in which the drinking water was contaminated by Class II wells.
>
> Page 8: Residents of 34 of the 100 largest cities in the United States rely on groundwater, as do 95 percent of rural residents.
>
> Page 11: Regulation of underground injection: If contamination is extensive, however, and covers a large area, rehabilitation may be extremely costly. In these cases, if left to cleanse itself, the process can take as long as 250 years.
>
> Page 19: Injecting Brines Can Continue to Contaminate Drinking Water: Because of possible underreporting by individuals whose drinking water was contaminated and difficulties in detection, the full extent to which injected brines have contaminated underground sources of drinking water is unknown. However 23 cases have been confirmed and 4 are suspected.
>
> These cases [of contamination] occurred in seven states: Kansas, Kentucky, Michigan, Mississippi, New Mexico, Oklahoma, and Texas.

[6] http://www.deq.state.va.us/air/permitting/Dominion_Warren/Comments/Ed_and_Karen_Hauswald.pdf

ICF was familiar with the risks associated with underground injection long before the NYSERDA contract. In April of 1993 under Contract Number: DE-AC22-92MT92*00*4, the DOE paid ICF $194,792 to write the ***STATE AND NATIONAL ENERGY AND ENVIRONMENTAL RISK ANALYSIS SYSTEMS FOR UNDERGROUND INJECTION CONTROL CLASS II RISK ASSESSMENT PROTOCOL.*** The following excerpts are instructive:

> Work on that project was delayed for several months due to the death of Mr. Troy Michie of Michie & Associates. The following selected excerpts from that ICF report are instructive:
>
> The General Accounting Office (GAO) has reported finding 23 cases since 1970 where Class II injection operations are believed responsible for contamination of a drinking water aquifer (GAO, 1989). This compares with over 160,000 active Class II injection wells nationwide. Nine of the cases reported by GAO resulted from purposeful injection directly into a USDW, which would be a violation of existing law.
>
> Underground injection of fluids has the potential to contaminate aquifers that are, or could be, used as sources of drinking water. However, documented cases of contamination due to underground are very few in number, and most of these cases are attributable to operating practices that were in violation of existing state and federal regulations governing underground injection.
>
> The reservoirs with the highest number of risk points were found in the Appalachian basin, where the large number of abandoned wells and numerous wells drilled prior to current construction and plugging practices would imply that risks may be higher relative to other areas. The next highest risk points were found in the Permian basin, which is a highly corrosive environment with substantial ongoing enhanced recovery operations. This finding is consistent with a previous risk assessment performed by Michie (1988).
>
> As noted above, data on the presence and depth of groundwater aquifers is probably the single most important risk factor. Yet no reliable, national source for data on groundwater is available, as described in Section II of this report.
>
> If the pressure is sufficient to force fluids the required distance, then the likelihood of a pathway for contaminants to travel through must be assessed. Two categories of wells must be considered: 1) current production and injection wells, and 2) abandoned wells and wells that are currently idle. Based on field experience, prior risk assessments, and other relevant literature, the key factors, affecting the potential for a pathway for contaminants to exist have been summarized as follows:

Current production/injection wells -

- Quality of the cement job, which affects whether a small annulus or channel may exist behind pipe
- Corrosion potential, which affects the likelihood of tubing or casing failures due to corrosive influences
- Use of construction practices that include short surface casing strings, which could mean that surface casing does not cover the lowermost aquifer, removing a layer of protection
- Use of unconventional injection well construction practices (such as tubingless or packerless construction), which can also remove one or more layers of protection for groundwater.

Abandoned and idle wells -

- Density of abandoned wells, which determines the number of potential conduits
- Density of idle wells, which also determines the number of potential conduits
- Historic plugging construction practices, which affects the potential for abandoned or idle wells to serve as conduits.

Given this prior knowledge coupled with the simultaneous and widely reported contamination occurring in Pennsylvania, how could ICF have been the source of the SGEIS statement that:" Hydraulic fracturing is not known to cause wellbore failure in properly constructed wells."?

Certainly one of the more disconcerting conclusions of the 1993 ICF report was the finding that the reservoirs with the highest number of risk points were found in the Appalachian basin. Another grave concern, especially in the face of NYSDEC's admission that it does not have enough staff to enforce the SGEIS, is ICF's conclusion that: "most of these cases are attributable to operating practices that were in violation of existing state and federal regulations".

In its August 7, 2009 report to NYSERDA, ICF concluded that "Poor casing construction or cementing practices can lead to leaks through the casing or vertical fluid movement in the annulus outside of the casing."[7]

However, ICF's final report continues: *§ 1.2.3 Case studies of fracturing fluid migration*

"The literature review performed as part of the present study did not identify any published case histories or studies that included direct observation of the migration of frac fluids in hydraulically fractured shale. "

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[7] SUBTASK 1.2: SUBSURFACE MOBILITY OF FRACTURING FLUIDS AND ADDITIVES, §*1.2.1 Potential exposure pathway, Page 21*

The woman depicted to the right may not have read those studies, but she is making a direct observation that drilling surfactant is pouring from a hillside in Pennsylvania. I too have personally observed a similar phenomena of drilling mud erupting into the Exceptional Value watershed of Silver Creek in Susquehanna County during a horizontal boring process. The point being that numerous phases of natural gas development adversely impact the environment and the lives of the people who inhabit what was once pristine countryside that has now become a gas field.

Using the Susquehanna County Gas Forum, in February of 2012, the citizens of Dimock, Pennsylvania, (specifically the fifteen families near Carter Road whose water has been impacted), were solicited to determine whether any of them had been contacted by NTS or any of the other consultants to NYSERDA. Had they been interviewed? No. Had their water been tested or sampled by these consultants? No! These people are not hard to locate and many are quite vocal about how natural gas development in Susquehanna County has adversely impacted their lives and the community character of Dimock.

Had NTS personnel been to Pennsylvania? Yes. Another look at time sheets submitted by NTC, show that Lisa Nagle, Darrow Mansfield and Bruce Cranston has all charged NYSERDA for “Travel to PA for site visit” on 5/14/2009. What site could have been more significant than Carter Road in assessing “the impact of drilling on community character”?

Recall that a literature search is not a substitute for empirical research, and that the relevance of empirical testing is dependent upon the attributes of reliability and validity.

- The estimate of less than 2×10^{-8} probability of injection wells contaminating a USDW is wrong. Twenty-three years ago the GAO knew of 23 cases of aquifer contamination in seven states from Class II injection wells and suspected 4 other cases.
- The estimate of - less than 2×10^{-8} - provided by J. D. Arthur is neither valid nor reliable. It has no relevance to the probability of New York State drinking water becoming contaminated due to shale gas development in the Marcellus or Utica formations.
- Being able to count properly is a prerequisite to most forms of scientific inquiry. But “***Modern Shale Gas Development in the United States: A Primer”*** - the blueprint for the SGEIS - was never intended to be a scientific document.
- Speak No Evil, See No Evil, Hear No Evil. The methods used by New York State to develop the SGEIS are both curious and circuitous, but they are not scientific.

> Rather they were intrinsically designed to justify an anticipated economic boost from a projected fifty years of intensive industrialization by developing the natural gas resources of the Marcellus and Utica shales, and to manipulate an unwitting public into believing that two hundred and fifty years of environmental contamination may not follow.

This spurious number of $2x10^{-8}$ is but a single example of the incompetence diffuse throughout the preparation of the SGEIS. For $433,883.24 in tax-payer money, the citizens of New York deserve better. I am calling upon the members of the New York State Senate and Assembly to hold hearings to determine how this Monkey Business came to pass and Who Wrote the SGEIS.

NOTICE

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Respectfully Submitted,

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