UNIVERSITY OF MICHIGAN

Technology Technical Report

HYDRAULIC FRACTURING IN THE STATE OF MICHIGAN

ABOUT THIS REPORT

This document is one of the seven technical reports completed for the **Hydraulic Fracturing in Michigan Integrated Assessment** conducted by the University of Michigan. During the initial phase of the project, seven faculty-led and student-staffed teams focused on the following topics: **Technology**, **Geology/Hydrogeology**, **Environment/Ecology**, **Human Health**, **Policy/Law**, **Economics**, and **Public Perceptions**. These reports were prepared to provide a solid foundation of information on the topic for decision makers and stakeholders and to help inform the Integrated Assessment, which will focus on the analysis of policy options. The reports were informed by comments from (but do not necessarily reflect the views of) the **Integrated Assessment Steering Committee**, expert peer reviewers, and numerous public comments. Upon completion of the peer review process, final decisions regarding the content of the reports were determined by the faculty authors in consultation with the peer review editor. These reports should not be characterized or cited as final products of the Integrated Assessment.

The reports cover a broad range of topics related to hydraulic fracturing in Michigan. In some cases, the authors determined that a general discussion of oil and gas development is important to provide a framing for a more specific discussion of hydraulic fracturing. The reports address common hydraulic fracturing (HF) as meaning use of hydraulic fracturing methods regardless of well depth, fluid volume, or orientation of the well (whether vertical, directional, or horizontal). HF has been used in thousands of wells throughout Michigan over the past several decades. Most of those wells have been shallower, vertical wells using approximately 50,000 gallons of water; however, some have been deeper and some have been directional or horizontal wells. The reports also address the relatively newer high volume hydraulic fracturing (HVHF) methods typically used in conjunction with directional or horizontal drilling. An HVHF well is defined by the State of Michigan as one that is intended to use more than 100,000 gallons of hydraulic fracturing fluid.

Finally, material in the technical reports should be understood as providing a thorough hazard identification for hydraulic fracturing, and when appropriate, a prioritization according to likelihood of occurrence. The reports do not provide a scientific risk assessment for aspects of hydraulic fracturing.

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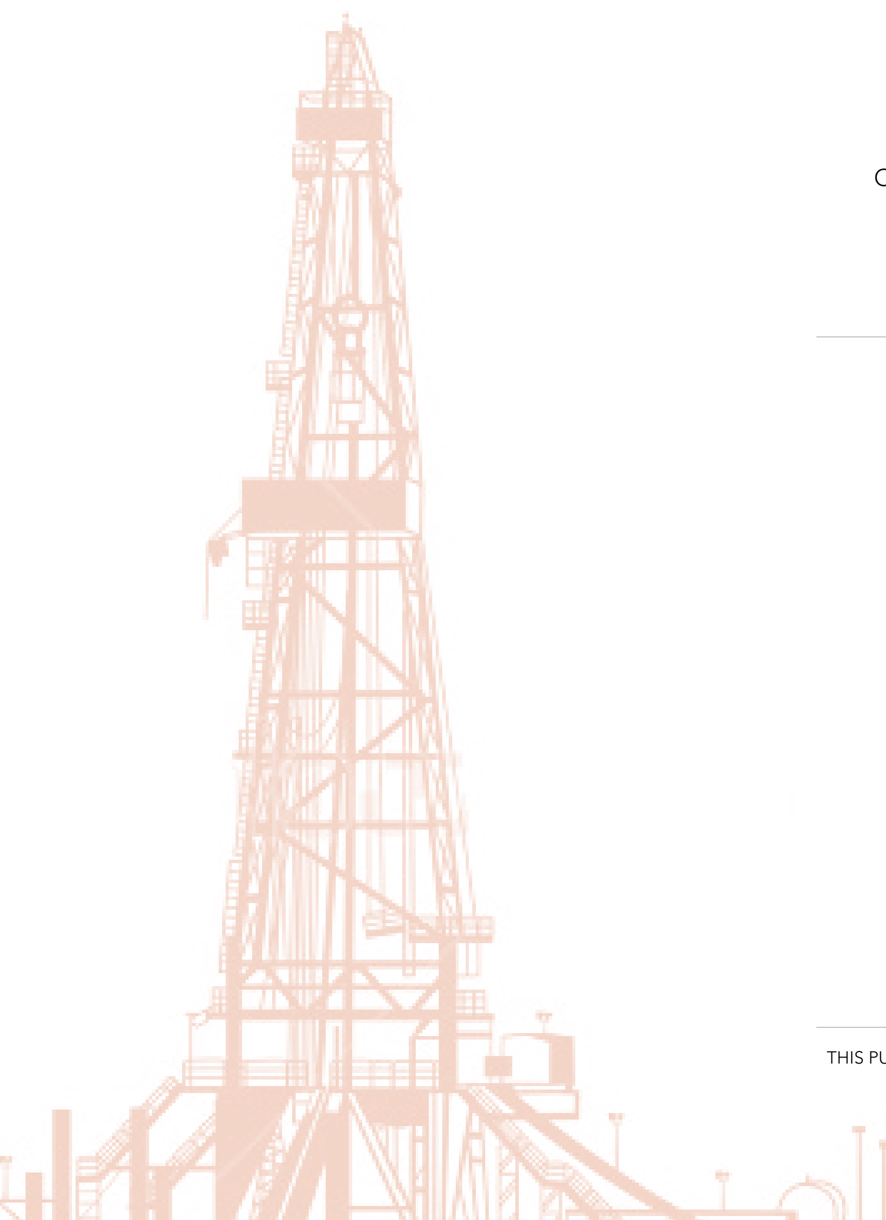
GRAHAM SUSTAINABILITY INSTITUTE INTEGRATED ASSESSMENT REPORT SERIES
VOLUME II, REPORT 2

HYDRAULIC FRACTURING IN THE STATE OF MICHIGAN

The Application of Hydraulic Fracturing Technologies to Michigan Oil and Gas Recovery

SEPTEMBER 3, 2013



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EXECUTIVE SUMMARY

This report focuses on technical issues related to hydraulic fracturing or "fracking" technologies and related methods of oil and gas recovery with special emphasis on methods that find applications in the State of Michigan. The report also identifies technical issues in the area of hydraulic fracturing that may require additional research. A brief review of the history of oil and gas recovery in Michigan is included, and the Michigan-based activities are discussed and contrasted with other U.S. and Canadian hydraulic fracturing activities. Since Michigan has limited experience with deep and/or directional drilling, this report also draws on the experience developed in other states.

Michigan, compared to other states in the U.S., has been a middle-of-the-pack producer of both oil and gas for many years. After the first *commercially successful* recovery of oil in Michigan in the Saginaw field in 1925, oil was also found near Muskegon, between Midland and Mount Pleasant, in the northern Niagaran Reef structure and along a trend between Albion and Scipio. Oil production in Michigan peaked in 1981-83 at about 32 million barrels/year but has since than declined by about 50%[1]. Natural gas production started later in Michigan, mostly in the Antrim Shale and in the northern Niagaran Reef, and peaked in 1996 at almost 300 billion cu. ft./year. Michigan's natural gas production has since fallen steadily to a little under 150 billion cu. ft./year[2,3]. For comparison, the U.S. uses about 18 million barrels of oil daily (6.6 billion barrels annually) and about 23 trillion cu. ft. of natural gas annually[4].

In the past 30 years, there have been no significant new oil finds in Michigan. However, considerable reserves of natural gas are believed to exist in deep shale formations such as the Utica-Collingwood, which underlies much of Michigan and eastern Lake Huron and extends well down into Ontario, Canada. Despite attempts dating back as far as 1859 in both Michigan and Ontario to extract gas, gas liquids and even oil from this very tight formation, there has been no successful commercial development to date. A few promising finds in Kalkaska County in Michigan, on Manitoulin Island in Lake Huron, and on the Southern Ontario mainland as far south as Niagara Falls have not yet led to commercial development. In view of the currently low price of gas, the high cost of drilling these deep shales, and the absence of new oil discoveries, it is unlikely that there will be significant growth of the oil and gas industry in Michigan (or Ontario) in the near-term future.

High-pressure (usually deep well) hydraulic fracturing (HF) represents one of many widely used methods of enhancing or initiating oil and gas recovery from deep, tight formations[5]. It has not found widespread application in Michigan, except for a few exploratory wells in the Utica/Collingwood and the associated A-1 and A-2 Carbonates. However, HF has been used in the form of low-pressure nitrogen foam fracking and also low-pressure water fracking in the Antrim Shale in the northern Lower Peninsula since the late 1940s (Hal Fitch, Michigan Department of Environmental Quality, pers. comm.).

Hydraulic fracking originated in 1947-1949, initially in Kansas, Oklahoma, and Texas as a means of stimulating production from uneconomic gas and (mostly) oil wells, and was quickly successful at increasing production rates by 50% or more, typically using hydrocarbon fluids (not water) as the carrier. Fracking now involves water mixed with *at least* 9-10% of sand or a synthetic ceramic such as calcined bauxite. The sand or ceramic particles are dispersed in the water to help keep the cracks in the formation open; the water also contains about 0.5 % of a total of about 10 chemical additives (such as surfactants and antibacterial agents similar to those used in dishwashing detergents) to help keep the newly-formed cracks open and clean. In the past, far less environmentally benign chemicals were added but the use of these has been discontinued by all of the major operators and their sub-contractors, partly as a result of public pressure and greater state disclosure requirements.

As noted, hydraulic fracturing was first performed experimentally in 1947 and the first commercial "frac job" was performed in 1949. As of 2010, it was estimated that 60% of all new oil and gas wells worldwide were being hydraulically fractured[6]. Many of these early fracking jobs were a mixture of stimulation of oil and gas production from existing under-performing wells and the development of new wells in "tight" formations from which commercially acceptable oil and gas flows could not otherwise be obtained. As of 2012, it is estimated that 2.5 million hydraulic fracturing jobs of all kinds have been performed on oil and gas wells worldwide, over one million of them in the United States[7]. To date in the U.S., fracking technologies are *estimated* to have been applied to more than 1.25 million vertical or directional oil or gas wells. Canadian companies have fracked at least another 200,000 wells[8]. In many recent cases, a combination of directional drilling and high-pressure multi-stage fracking has been used to access oil or gas trapped in larger 'drainage volumes' of a reservoir.

Modern high-pressure HF is generally applied to deep, often directional wells and uses what are often perceived as high volumes of water (typically up to 7 million gallons per well although in a very small number of cases, including one in Michigan, quantities over 20 million gallons have been reported, usually associated with unusually low flowback water recoveries and apparently associated with abnormal "sinks" for water deep underground). Compared to other industrial or agricultural uses, these volumes of water are not large, but water availability tends to be a local or regional problem, and its use for fracking has raised concerns especially in the western U.S. To decrease the use of water, several non-aqueous fracking methods are now in use or being developed. A more serious problem is disposal or treatment of the often-substantial fraction of the fracking water returned as so-called flowback water and also of any subsequently produced water. Flowback or produced water is now often (as in Michigan) disposed of in Federal or State approved deep injection wells. An increasing and so far partially successful effort is being made to develop better water treatment methods for the often highly saline return water which may also contain small amounts of hydrocarbons, some of them toxic[9]. If these treatment methods are effective, the water can be re-used—and in some cases is, in Colorado and Pennsylvania, for example.

Another concern for the natural gas industry is potential leakage of methane. Methane is a potent greenhouse gas. Over the years, substantial efforts have been made to gradually decrease the number of both large and small leaks in the national distribution system. Newly designed pipeline compressors, once a major source of methane leaks, are now essentially leak-proof while gas processing plant hardware and instrumentation is improving through the use of welded joints and changes in design. In the past, fracked gas well sites used to be fairly major contributors to methane leaks due to careless handling of flowback water and practices such as open-well liquids unloading and incomplete combustion in flares. Field monitoring of methane emissions from such sites now shows them to be comparable to conventional gas wells producing under reservoir pressure, and field levels of methane leaking from HF sites are now generally low, as was very recently confirmed by the U.S. Environmental Protection Agency (EPA)[10]. Although methane leakage remains a concern for the natural gas industry in general, the probability of significant methane leakage in deep shale drilling, completion, hydraulic fracturing, testing, and production in Michigan is quite low provided that best practices are adhered to. However, local distribution systems in older cities are still thought to be a major source of methane leakage.

Fracking, like oil or gas drilling, involves complex equipment and procedures operated by humans. Errors and accidents do occasionally occur, sometimes leading to the escape of fracking water or, much more often, gas into the atmosphere or into groundwater or drinking water aquifers. Fortunately, such events have become increasingly rare over the past ten years as both regulations and industry practices have improved. Most recent incidents have involved faulty equipment or its faulty installation. This report reviews the safety record accumulated over more than 30 years of high-pressure deep well fracking (and a much longer period of all forms of fracking) and arrives at the conclusion that the fracking process has a good safety record.

Phase 2 work that is proposed includes a long-overdue study of the adsorption of natural gas components on minerals that are found in Michigan's gas reservoirs as well as a more quantitative look at the physical characteristics of the Collingwood, Utica, and related shales that are thought to be important to Michigan's natural gas future.

1.0 INTRODUCTION

Although Michigan has long been a moderately prolific (albeit now declining) producer of oil and gas, in common with many other states, it is in most ways geologically unique. While it has some characteristics in common with neighboring Indiana, Ohio and Ontario, Canada, the history of "fracking" in other states such as Ohio, Pennsylvania, New York, Texas, Colorado or Wyoming has limited relevance in Michigan. Among American states, Michigan has been a middle-of-the-pack producer of both oil and gas for many years. This report will combine that part of out-of-state experience that is relevant to Michigan with the state's 100+ years of in-state discovery and production of oil and gas. It will provide an analysis of the past, present, and likely future of the use of formation drilling and fracturing technologies to enhance natural gas and oil production in the state.

The first ***commercial*** discovery of oil in Michigan was made in the Saginaw field in 1925. This was followed by many other finds near Muskegon, between Midland and Mount Pleasant, in the northern Niagaran Reef structure and along a trend between Albion and Scipio[11]. Oil production state-wide increased steadily and peaked in 1981-83 at about 32 million barrels/year but has declined by more than 50% since that time[3]. Natural gas production developed somewhat later in Michigan, mostly in the Antrim Shale and in the northern Niagaran Reef, and grew steadily until 1996 when it peaked at almost 300 billion cu. ft./year. Michigan's natural gas production has since fallen to a little under 150 billion cu. ft./year. For comparison, the U.S. uses about 18 million barrels of oil daily (6.6 billion barrels annually) and about 23 trillion cu. ft. of natural gas annually[7].

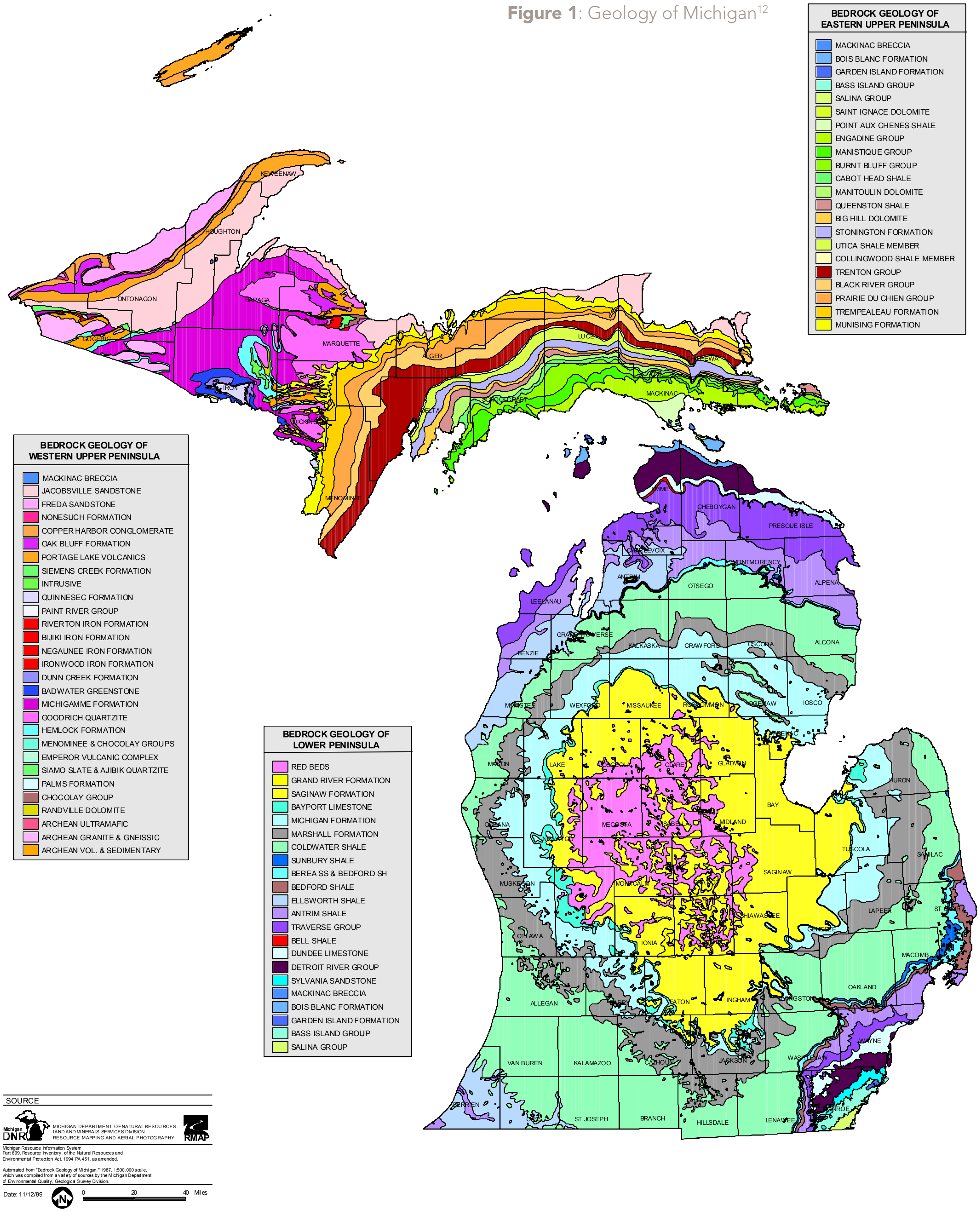
No significant new finds of oil have been made in Michigan in the past 30 years. Additional natural gas is thought to exist in deep shale formations such as the Utica-Collingwood, which underlies much of Lower Michigan and Lake Huron and extends well down into Ontario, Canada. Attempts have been made in both Michigan and Ontario to extract gas, gas liquids and even oil from this very tight formation dating back to 1859, but so far there has been no successful *commercial* development. There have, however, been one or two promising (but so far undeveloped) finds in several areas such as Kalkaska County in Michigan and on Manitoulin Island in Lake Huron and on the Southern Ontario mainland as far south as Niagara Falls. Notwithstanding these positive indications, the low price of gas, the high cost of drilling these shales, and the absence of new oil finds do not bode well for the near-term future of the oil and gas industry in Michigan (or Ontario).

2.0 STATUS AND TRENDS

2.1 A Brief History of Oil and Gas in Michigan and Vicinity

The following map shows the well-established bedrock geology of Michigan[12]. The map shows the irregular "stack of dinner plates" characteristic of Michigan geology which has resulted in formation

Figure 1: Geology of Michigan[12]



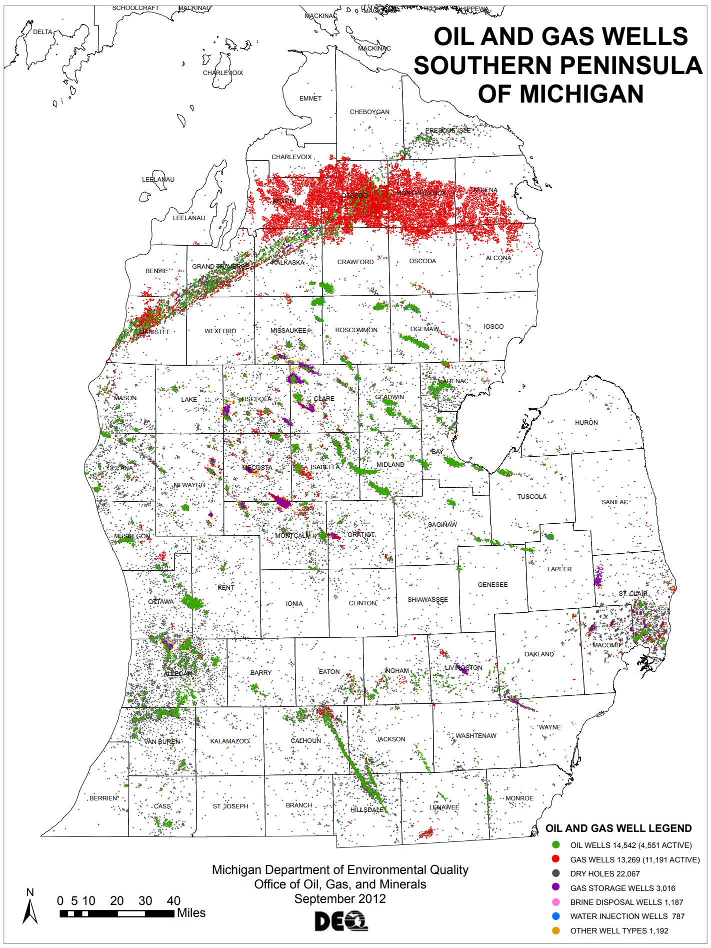


Figure 2: Location of oil (green) and gas wells (red) in Michigan[13]

outcrops quite remote from the state itself—in Ontario or under Lake Michigan, for example.

Figure 2 shows the location of oil (green) and gas (red) wells in Michigan. The red area at the top of the Lower Peninsula represents the Antrim shale formation. This is still a major gas producer, but at only about half of its former peak rate. Other oil and gas wells are distributed over the state in a manner that more or less follows the geology shown in the preceding map, but its location has been sufficiently unpredictable to have made wildcatting a high-risk occupation in the state for many years!

By odd coincidence, the first discovery of oil related to Michigan's rather unusual geology was made in 1858 at what is now Oil Springs, Ontario, where there were long-known "gum" beds (the gum being the residue left after the lighter fractions of the naturally seeping crude had evaporated). This was where Michigan's Dundee limestone formation (or 'dinner plate') outcropped at the edge of the Michigan Basin. A hole was dug to a depth of 13 ft. (later deepened to 39 ft.) and free-flowing crude oil was observed. This occurred a year before Edward Drake's famous 1859 well at Titusville, PA, which is usually considered the forerunner of the U.S oil industry. Michigan's first recorded oil field was discovered in St. Clair County in 1886 and also tapped the Dundee formation at 575 ft. The oil recovered was used locally "as was", mostly for the lubrication of heavy machinery. The last of this field's oil wells was plugged in 1921. Oil was sought by drilling in the Upper Peninsula (UP) in the very early 1900s, but exploration in the UP has never resulted in a commercially-viable oil or gas find.

In Michigan, the Collingwood/Utica formation that lies deep under much of the state (at 10,000–12,000 ft.) has not yet proven to be a commercial source of oil or gas. However, as noted above, the Collingwood also underlies much of Lake Huron as well as Manitoulin Island and the Bruce Peninsula of Ontario and gets its name from the town of Collingwood, ON, on the SE shore of Lake Huron (where the formation forms the shoreline but is overlain just further south by the Blue Mountain shale). Oil was produced from the Collingwood at the tiny town of Craigleith just west of Collingwood in 1859[14]. The enterprise failed by 1863. The oil in that part of the Collingwood is the high-kerogen variety also found in the Green River Basin in Wyoming, Colorado and Utah[15]. It can be extracted only by retorting the shale and condensing the vaporized product—a process that even now is not economically viable. There are also numerous developmental gas wells in the Ontario sector of the Collingwood, including some on Manitoulin Island.

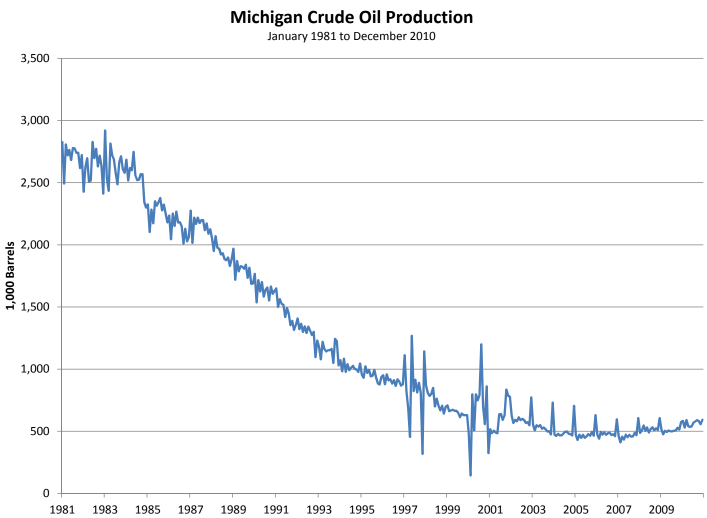
Fortunately, most of the oil discovered in Michigan has been much more conventional in nature and therefore much more accessible. However, there have been few recent discoveries and the state's production of both oil and gas is now in sharp decline.

The widely-accepted beginning of Michigan's *commercial* oil production began with the discovery of the Saginaw Field, just south of the city of Saginaw, in 1925. The period from 1925 to 1955 resulted in numerous oil and gas discoveries throughout the Lower Peninsula, along with a lot of dry holes. Of greatest note was the Muskegon field (1927) that was followed by several additional significant finds a little farther south and east in Ottawa, Allegan, and Van Buren counties. Oil was also discovered between what are now Mount Pleasant and Midland in a quite prolific area that involved Osceola, Clare, Gladwin, Midland, Isabella, and Mecosta counties. Most of the wells were shallow and produced only oil from the sandstone that underlaid the famous "red beds"; nevertheless, the result made Mount Pleasant the "Oil Capital of Michigan".

The Albion-Scipio Trend in Calhoun and Hillsdale counties was discovered in the mid-1950s and produced 125 million bbl. of oil, thus qualifying as a major field. (There was probably at least three times that amount of oil originally in place; enhanced oil recovery methods will eventually recover more of it. A small amount of gas was recovered from the northern end of the trend in Calhoun County). It was followed in the late 1960s by the Niagaran Reef Trend which resulted, by the 1970s, in a tripling of Michigan oil production and multiplying natural gas production by 6 times.

By 1979, Michigan's total oil production had reached 35 million barrels annually. It had declined to about 6.5 million barrels by 2010 in the absence of any additional major finds, but increased slightly to almost 7 million barrels by 2011, the last year for which data are available, mostly because of aggressive workovers and a few new but small discoveries. Since this total is far less than Michigan's annual oil consumption, the state imports about 97% of its total petroleum needs, mostly from western Canada via pipelines that pass through the Chicago area. In 2009, Michigan consumed 163.6 million barrels of petroleum product. Relative to petroleum, Michigan's natural gas production is more substantial and accounts for about 18% of the state's demand for natural gas. The following Figure 3 shows ***monthly*** production data.

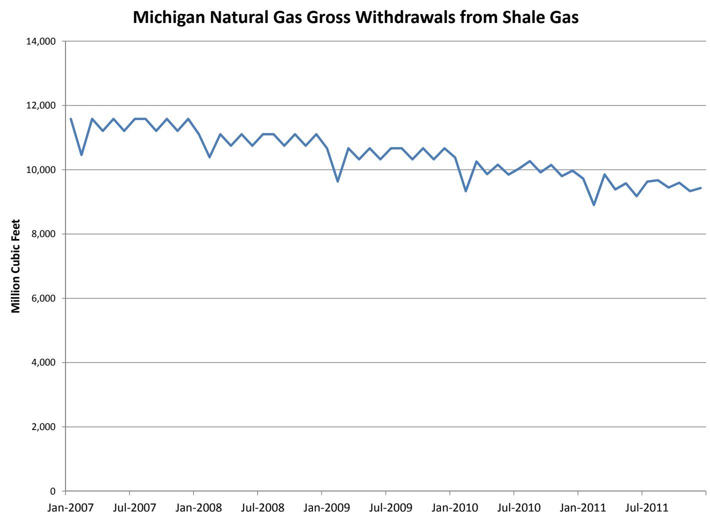
Figure 3: Michigan Crude Oil Production[16]



In the early 1980s, deep-strata natural gas production (for example from the northern Niagaran Trend) began to make a significant contribution to Michigan's economy while there was also a major expansion of drilling activity in the long-known Antrim shale formation in the northern Lower Peninsula. All of these more recent fields, including the Antrim, are still significant producers, primarily of gas. However, the production from all of them is in decline. Production in the Antrim shale stood at 131 billion cubic feet per year (bcf/y) in 2008, but this figure has been steadily declining, only reaching 85 bcf/y last year (2011). It is projected to continue falling and to stabilize at approximately 62 bcf/y by 2020. Total in-state natural gas production peaked at 280 bcf/year in 1997 but had declined to 141 bcf/year by 2010 due to decreased well productivity. Again, note that U.S. annual consumption is about 23 *trillion* cu. ft./year while Michigan's annual consumption was about 765 billion cu. ft. in 2010[4].

The following figure (Figure 4) shows ***monthly*** production data of Michigan *shale* gas.

Figure 4: Michigan Natural Gas Production from *Shale Gas*[17]



Very recently, the discovery of gas and gas liquids in the Collingwood and Utica deep shales (which also happen to outcrop in Ontario along the southeastern edge of Lake Huron - primarily under the Blue Mountain Shale - as does the Antrim Shale in the southwestern corner where it becomes the Kettle Point shale in Ontario) have caused a flurry of lease sales in the state. Activity has dropped, however, perhaps temporarily, as a result of the very low price of natural gas[18] and what has turned out to be relatively intractable "tight" shale. The potentially productive part of the Collingwood shale in Michigan is at least 10,000 ft. deep (about 2 miles) and will typically require the drilling of several wells and laterals from the same pad to achieve acceptable production rates. These are costly requirements. At current prices, very few operators working in deep shale can hope to make money, and a return of major activity will have to wait until gas prices reach *and stabilize* at a minimum of $6-$8/MCF. The price of gas appears to have stabilized recently after peaking at about $4.00 and falling somewhat and is now (May, 2013) again trading at about $4.00/MCF[18].

As a sidebar, the Kettle Point (Antrim extension) shale that runs roughly from east of Sarnia almost down to Windsor/Chatham along the east side of the St. Clair and Detroit Rivers has been a local gas producer in the past[19]. It and other shale formations in the vicinity (including the Hamilton Group, which is mostly limestone, and also the northern extremity of the Marcellus shale which extends under Lake Erie) provided the gas that started what is now a very large petrochemical and oil refining complex in Sarnia, ON.

Numerous water wells were also drilled in the vicinity and almost all have produced gas along with the water, but certainly not as a consequence of gas drilling in the area (which many of them predate). It is also worth noting that shallow-water drilling has also long taken place in the Canadian side of Lake Erie near Erieau, ON, tapping the extreme northern edge of the Marcellus formation. There are still several active gas plants in the area that refine gas from Lake Erie and sell it to Union Gas of Chatham, ON. Otherwise, there has been little or no attempt to commercialize gas from the Kettle Point, Hamilton Group, Collingwood, Blue Mountain/Utica and other gas-bearing structures in Ontario. Recently, the Government of Ontario has been criticized for its failure to capitalize on these probable resources, but that seems to be changing[20].

Curiously, there are few reports of gas in areas west of the Detroit and St. Clair Rivers. These areas are now highly populated. Very modest quantities of both oil and gas have been produced in Oakland County, apparently from the southern Niagaran Trend, but by far most wells drilled were dry. Wayne County has recently supported a ban on fracking (of little note, since the county has no known commercial oil or gas fields and lies well south of the Collingwood/Utica shale). As noted earlier, St. Clair County was the site for Michigan's first oil field in 1886 (in the Dundee Formation) and still has producing wells. There were also a few at one time in Macomb County, but most wells drilled there were dry, as was the case in Washtenaw County.

2.2 Gas Storage in Michigan

During the summer months when gas demand is usually low, gas is pipelined to Michigan and stored underground in specifically appropriate locations, often former brine wells or depleted gas wells. At 649 billion cu. ft., Michigan has more gas storage capacity than any other state. During the winter heating season, this gas is withdrawn and used both in-state and by neighboring states.

2.3 Realistic limits on resource recovery

In the case of natural gas, most of the gas in a conventional reservoir can usually be recovered given sufficient natural permeability, porosity (or fracturing, natural or man-made) of the supporting rock formation. A much smaller proportion may be recovered from "tight" formations with limited permeability such as tight sandstones or coal bed formations. Most formations, especially shales with high organic content, also retain a certain amount of methane that is adsorbed on to mineral surfaces. This amount is unpredictable and often indeterminate and in some cases may be replaced by carbon dioxide or other compounds as the methane is withdrawn. In very tight formations with low permeability and low interconnected porosity, very little gas (or oil) flow may be established regardless of how the formation is drilled or fractured.

In the case of oil resources, the story is quite different. In the early days of oil production in Michigan, in the Spindletop field in East Texas, and in many other states, wells were in many cases drilled too close together and oil was pulled from what was a common reservoir too quickly, often leading to water flooding, which can effectively stop oil flow in small channels in the formation through surface tension effects. For example in East Texas, only 10% of the oil now known to have been in place in several major reservoirs was recovered. The remainder may be lost forever or at least until a new technology is developed to recover it. Even today with optimum drilling practices, it is unusual to obtain more than 35% of the oil in place by primary production methods. Another 15-25% can sometimes be recovered by enhanced oil recovery (EOR) technologies, some of which are discussed below, but that still leaves a lot of oil in the ground and currently inaccessible.

2.4 Recovering More of the Resource

There are many ways by which more of the energy resource in the ground can be recovered. They are summarized briefly here because most have been important at times in Michigan. Hydraulic fracturing (HF) can be viewed as one of these methods. It has seen little use in Michigan in the manner that is currently practiced in, say, Pennsylvania, North Dakota or Texas, other than in a few exploratory wells in the Utica/Collingwood and the associated A-1 Carbonates. However, it has been used in the form of low-pressure nitrogen foam fracking in the Antrim Shale in the northern Lower Peninsula since the late 1940s.

All methods of fracking now involve the use of a high pressure fluid, typically water, with 9-10% (and often up to 20%) of sand or a synthetic ceramic such as calcined bauxite dispersed in the fluid to help keep the cracks in the formation open after fracturing; the fluid also contains a total of about 0.5 % of chemical additives (such as surfactants and antibacterial agents, most of which are used in other commercial or domestic operations such as dishwashing) to help keep the newly-formed cracks open and clean. At one time, and especially in the 1940s, 1950s, and even as late as 2000, far less environmentally benign chemicals were employed (Napalm or gelled gasoline was one very early example). A long list of chemicals once, and in some cases still, in use can be found at the Fracfocus.com website[21]. A more current list of chemicals commonly in use can be found at the recent ASTM Jacksonville meeting proceedings[22]. In the past, far less environmentally benign chemicals were added, but the use of these has been discontinued by all of the major operators and their sub-contractors, partly as a result of public pressure and greater state disclosure requirements.

Hydraulic fracturing was first performed experimentally in 1947, and the first commercial "frac job" using hydrocarbon fluids, mostly locally-produced crude oil, with some rather unusual additives, was performed (with only modest success) in 1949. Water was used for hydraulic fracturing only after 1953. As of 2010, it was estimated that 60% of all new oil and gas wells worldwide were being hydraulically fractured[6]. As of 2012, it is estimated that 2.5 million hydraulic fracturing jobs of all types (not all of them deep or involving directional drilling) have been performed on oil and gas wells worldwide, more than half of them in the United States[7]. To date in the U.S., fracking technologies are *estimated* to have been applied to more than 1.25 million vertical or directional oil or gas wells. Canadian companies are said to have fracked at least another 200,000 wells. In many recent cases, a combination of directional drilling and high-pressure multi-stage fracking has been used to access oil or gas trapped in larger 'drainage volumes' of otherwise unproductive reservoirs. Currently, about 35,000-40,000 U.S. wells are being hydraulically fractured annually with a far greater proportion of them directionally drilled than previously.

A major issue with modern high-pressure, deep formation HF is its use of what are often seen as high volumes of water. Based on information posted on FracFocus for 16 wells, Michigan has seen a wide range in terms of water use from as low as 14,000 to over 21,000,000 gallons of water[21]. These volumes are not in fact large compared to other industrial or agricultural uses (for example golf courses in the arid U.S Southwest), but flowback water in Michigan is disposed of via deep well injection. Water availability tends to be a rather emotional local or regional problem, especially in the western U.S. and reduction in its use is always desirable. Water typically costs $0.10 to $0.25/gallon (up to $0.75/gallon under drought conditions) which is a significant incentive to limit use at current low gas prices. Several non-aqueous fracking methods are now in use or being developed, but they are more costly than water-based hydraulic fracking.

A more serious problem is disposal or treatment of the often-substantial amount of the fracking water returned as so-called flowback water and also of any subsequently produced water. In Michigan, this water is sent to disposal wells regulated and permitted under the EPA Safe Drinking Water Act through the Underground Injection Control as Class II wells[23]. These wells are also regulated under Michigan's Oil and Gas Regulations[24]. An increasing effort is being made to develop water treatment methods appropriate to the often highly saline return water which may also contain small amounts of hydrocarbons, some of them toxic. If these efforts are successful, as they have been in a limited number of cases in PA and CO, the water will be re-used.

2.4.1 Directional Drilling

Conventional vertical drilling can access only that part of a gas- or oil-bearing formation with which the drilled hole intersects. Since most such formations have a significant lateral dimension, usually extending 360° around the vertical well, drilling one, or preferably several, lateral (directional) wells into the producing formation can provide much greater access to oil and/or gas. If exclusively 'dry' gas (free of hydrocarbon liquids) is being produced, the lateral can be nominally horizontal because no liquid drainage is required. (Nevertheless, some liquids often accumulate at the bottom of the vertical part of the well; it eventually blocks the flow of gas and must be removed from time to time by a process known as 'liquids unloading'.) In many cases, the well produces some liquids, either water or gas liquids (typically C_2 to C_6 alkanes or a gasoline-like condensate). In this case, the lateral segment of the well is often drilled at a slight angle to facilitate drainage and pumps may be installed to remove the liquids. In many cases, the formation being accessed is not exactly horizontal and the slope of the lateral well may be designed to follow the formation. Although the term "horizontal" is often applied to such laterals, very few of them are precisely horizontal.

The success of any drilled hole, whether vertical or directional, depends on the pore size and/or the size of flow channels in the surrounding formation. Most pores or channels are in the 1 to 100 millidarcy range[i].

Even with extensive directional drilling of laterals, only a fraction of the gas- or oil-bearing formation can be accessed. The volume of rock that can be fracked around any one lateral is limited, and there are large potential 'drainage volumes' that are *not* accessed. Of course, more holes and more laterals (only one per vertical hole is possible if casing integrity is to be maintained although many vertical wells can be drilled from a single pad) can improve access, but that is very costly.

2.4.2 Explosive Fracturing of the Energy-Bearing Formation

Explosive fracturing was widely employed at one time during the nineteenth and first half of the twentieth century. It was used only for what were intended to be vertical holes (early cable-tool and similar drilling technologies often resulted in holes that deviated significantly from the vertical; even modern deep rotary drilling can suffer that problem as a result of contact of the rotary drill bit with large, hard rocks) and consisted of lowering or dropping a dynamite charge into the well which was then ignited with a red-hot rod or, later, with an electrical charge via a wireline. The result, while often spectacular, fractured the rock in only a limited volume of the formation around the bottom of the hole. Nevertheless, gas or oil flow was enhanced although the process often had to be repeated frequently. Explosive charges are still used to perforate a

i. The darcy is a measure of permeability. A gravel bed has a permeability of about 100,000 darcys while sand beds approximate 1.0 darcy. At the other extreme, granite typically has a permeability of 0.01 micro-darcys or 10 nano-darcys.

well casing in preparation for hydraulic fracturing but are not used for formation fracturing per se.

2.4.3 Hydraulic Fracturing (HF) of the Formation

Both vertical and horizontal wells generally require some form of formation fracturing process to provide greater access to the gas or oil contained therein. In recent years, some 85% of wells drilled in North America have been subjected to some form of fracturing process, usually hydraulic, but not always involving water use. Many of them have involved directional drilling.

A few rock formations, such as the Antrim shale in the northern lower peninsula of Michigan and the New Albany shale in Indiana/Illinois, are already highly fractured and flow gas without much additional fracturing once the substantial amount of naturally-occurring water is removed from the formation. In some cases, pressurized nitrogen foam (in water) may be used, primarily to clean drilling mud and rock chips out of natural fractures that intersect with the well walls, and hence casing, in the production zone. Most other shale formations, while often naturally fractured, must be additionally drilled and fractured to achieve sufficient flow of gas or liquids. 'Tight' rock formations such as sandstones or limestones (carbonates) may require fracturing if the porosity is very small or not well interconnected. In some extremely tight formations with porosity in the micro-darcy range (see earlier footnote), even extensive fracturing may recover only a small proportion of the gas or oil in place in the fractured zone. Gas will flow through solids that are of low porosity more easily than will oil, which requires at least 10-100 times the porosity. In both cases, the presence of water may effectively block the pores.

Hydraulic fracturing can be very effective in formations that are naturally cracked but in which the cracks are too narrow to permit flow, especially of oil. In such cases, water at a pressure of up to 15,000 psi is forced into the formation through holes in the steel well liner (casing) that is cemented to the bore wall; the water opens the cracks. Up to 20% of sand or ceramic in the water, assisted by a small number of chemicals at high dilution (roughly 0.5% in total), acts as a 'proppant' to hold the cracks open and to permit the flow of gas and oil.

The water that is injected into the well contains only a modest amount of chemicals, predominantly very dilute hydrochloric acid. In most cases, the injected water collects additional chemical compounds from the formation (the amount picked up may be small in true dry gas wells) such as highly saline water containing mostly sodium, calcium, and magnesium chlorides and some hydrocarbons. This "flowback water" presents a disposal problem and must either be treated for re-use (this can be difficult due to the high salinity) or disposed of in deep wells. In Michigan, these disposal wells are regulated and permitted under the EPA Safe Drinking Water Act through the Underground Injection Control as Class II wells[23]. These wells are also regulated under Michigan's Oil and Gas Regulations[24]. Flowback water can be handled only rarely in conventional waste water treatment systems (such handling is prohibited in Michigan). Increasingly, specialized waste water treatment systems are being developed that involve either distillation or reverse osmosis to reduce salinity to levels that permit re-use. They are in common use in Pennsylvania's Marcellus shale and in Colorado's Denver foothills area.

2.4.4 Formation Fracturing with Minimum or Zero Water

The possibility of using compressed nitrogen or CO_2 foam to fracture "easy" formations that contain already substantial amounts of natural fractures and cracks was mentioned above. This method is environmentally appealing since no chemicals other than a foaming agent and sand are used. The method has proved very effective in vertical wells with no laterals such as those commonly used in Michigan's Antrim shale formation but has been less effective elsewhere. Liquid nitrogen and CO_2 must be brought to the drilling site by truck, which adds to traffic disruption and road damage.

An alternative method developed by GasFrac Energy Services Inc., a Canadian company headquartered in Calgary, uses gelled LPG (liquefied petroleum gas) as the fracking agent. Once it is used, the gel 'disintegrates', and the LPG Components (propane, butane, etc.), are recovered in the well product. The method has now been used in over 1,000 frac jobs in Canada and the U.S. (including Ohio's Utica shale as well as in the Eagle Ford shale formation in Texas). No problems have been reported, but given the explosive nature of the LPG components when mixed with air, all oxygen and ignition sources must be eliminated. The method uses no water but costs about 20% more than water-fracking a well of similar depth and is thus being used primarily for oil-producing wells, given present low gas prices. Several competitors for this technology have recently appeared, at least one (eCorp Stimulation Technologies LLC of Houston) using only propane in the Eagle Ford Shale.

2.4.5 Vacuum Application

Several operators have sought to improve declining gas well productivity by applying a modest vacuum (typically 2-3 inches of mercury or about -0.1 bar) at the top of the well. In most states, vacuum extraction requires a special permit and very few have been issued. Concern has been expressed that the application of a vacuum will draw gas from neighboring properties. The technology has been so little practiced that it is not clear if it is effective.

2.4.6 Liquids Unloading

Even in so-called dry gas wells, liquids may accumulate over time at the bottom of the well and inhibit gas flow. The liquid may be water or, in wells producing under significant reservoir pressure, can be gas liquids (typically C_2 through C_6 hydrocarbons or possibly natural gasoline/condensate). In some vertical wells, a submersible pump may be placed in a sump - usually an extension of the vertical well bore - to remove these liquids. The old practice of opening the well and letting the gas flow blow the liquid out of the well has supposedly been discontinued everywhere since both the gas and the gas liquids have significant value and, if released, have a negative environmental impact. However it is carried out, the practice is known as 'liquids unloading' and plays an essential role in maintaining the productivity of wells, but may contribute significantly to methane emissions[25].

2.4.7 Water Flooding

Intentional and well-designed water flooding of declining *oil* (not normally gas) wells can enhance production of oil by pushing it through the formation toward the production hole. This requires the drilling of one or more water injection wells around the production well—a significant added cost. Care is necessary to prevent water breakthrough to avoid water replacing oil in the producing formation. This was a common reason for the premature failure of many early oil wells in over-produced fields (including some in central and western Michigan); in those cases, the water can fill the capillaries or pores through which oil is flowing and block its movement. That oil cannot then be produced using any currently available technique.

2.4.8 Polymer flooding

In this case, water gelled with an added proprietary polymer formulation is used in lieu of "straight" water. The effect is similar to water flooding, but the gelled water is less likely to "get ahead" of the oil front to block it. Instead, it pushes the oil ahead of it. We are not aware of its use in Michigan, perhaps because of its high cost.

2.4.9 Steam flooding

In this case, steam is injected into the formation to heat the oil and reduce its viscosity. The oil then flows more easily toward the production well. This is a preferred technique for heavy oils such as those found in, for example, California's Santa Barbara region and in southern Alberta. However, in deep formations, the heat loss from the steam on its way to the point of use may make the method ineffective. Solvent (e.g., kerosene or gas liquids) may be added to the steam to further enhance recovery.

2.4.10 Carbon Dioxide Flooding

Carbon dioxide injected at moderately high pressure (3,000 psi) into oil-bearing formations can greatly reduce the viscosity of some (but not all) crude oils and also, at least temporarily, increase the volume (and reduce the density) of the oil. As a result, the oil flows more easily in the reservoir and more—sometimes much more - may be produced than in the absence of CO_2. This method of enhanced oil recovery has been widely used with good effect, especially in the Permian Basin of West Texas (using CO_2 from gas wells in New Mexico) and has also been promoted as a method of sequestering carbon dioxide. However, little work has been done on the eventual disposition of the CO_2; for example, it is not known whether it combines chemically with the oil and thus remains sequestered or desorbs from the oil during and after production. In the latter case, it would have to be re-captured and re-sequestered with little net benefit to the CO_2 emissions problem. There is a modest amount of evidence that a combination of methane and carbon dioxide may be slightly more effective than CO_2 alone.

A few enhanced oil recovery (EOR) experiments using CO_2 have been conducted in Michigan's northern Niagaran (Middle Silurian) Pinnacle Reef structure. Elsewhere in the world, numerous CO_2—EOR projects exist, some developmental and some commercial. For example, in Alberta, Shell is building a pipeline to take combustion-generated CO_2 from its northern Alberta oil sands operation, first of all to underground storage and then on demand south to the Cold Lake area to be used in enhanced conventional heavy oil recovery. Power station combustion CO_2 injection is also being explored for North Sea oilfield use by both Norway and the UK. For those who are interested, the Oil & Gas Journal publishes a list of EOR projects every other year. There are many such projects, not all involving CO_2 injection.

2.4.11 Solvent Flooding

Another, relatively costly, method of enhanced oil recovery that does not appear to have been used commercially in Michigan involves the injection into the formation of a heated solvent such as kerosene, naphtha (natural gasoline), C_2-C_6 gas liquids or even LPG into the formation to thin the crude oil and thus stimulate flow. The solvent is sometimes mixed with steam to provide an additional incentive to flow. Versions of this technology (for example, the N-Solv Process) are increasingly being used in the Canadian Oil Sands to enhance the productivity of steam-assisted gravity drainage (SAGD) bitumen production but have seen relatively limited use elsewhere.

2.4.12 Fire Flooding or In-situ Combustion

To the best of our knowledge this method of enhanced oil recovery has not been widely used in Michigan. It consists of using in-hole combustion, using injected air and gas or other combustible fuel to generate a flame front at the foot of the injection well; a combustion wave is driven through the reservoir where it heats the oil and lowers its viscosity and drives it toward a parallel production well. This method has been used for recovery of heavy or waxy crudes in areas such as southern and central Alberta and has been experimented with in California and elsewhere where heavy crudes are common.

3.0 CHALLENGES AND OPPORTUNITIES

In the following section, the technical aspects of current methods for hydraulic fracturing will be reviewed, and where appropriate, technical challenges and opportunities for improved techniques will be discussed. Furthermore, areas where further research is needed will be identified.

3.1 Hydraulic Fracturing (also Fracking or HF)

This topic has been the subject of a separate report by the authors[26]; that report looked at HF from a national perspective. It detailed much of the technology in common use and that will therefore only be summarized here. Michigan has not been typical in its use of HF (as compared to states like Texas, Arkansas, Colorado and North Dakota, for example) so its fracking history and current practice is somewhat unique.

Fracking or HF is a technology used (in a variety of different ways) to open or create cracks in an oil- or gas-bearing formation so that more product flows from the well. Almost all wells can benefit to some degree from fracking; ***about 85% of the wells drilled in the U.S. in the past decade have been fracked***. In total, about 1.25 million U.S. wells have been fracked as well as about 200,000 in Canada, and at least 700,000 in other foreign countries and off-shore, so there is ample experience on which to rely in determining the most appropriate method to use and the environmental and safety rules that are appropriate. These have been documented in very substantial detail by the American Petroleum Institute[27]. The fracking operations by the oil and gas industry and its many sub-contractors are regulated by the governments of oil- and gas-producing states and nations.

3.1.1 Fracking Methods

Most fracking begins with the construction of a drilling pad that may be 1-4 acres in area. The pad is now often covered with a thick polyethylene sheet and a thin layer of absorbent material (often just sand or soil) to minimize the impact of spills. The location of the pad site and the position of the drilling rig are primarily determined from a variety of information on the geological substructure and the estimated probability of striking oil and/or gas, but a wide range of environmental factors are also considered. A drilling rig is brought in and situated over the intended well site. Vertical drilling is then begun. In the case of formations like Michigan's Antrim shale, the hole is drilled down into the production zone, the rig is removed and preparations are made to frack the well (see below). A drilling rig requires a lot of energy to turn the rotary drill bit and is usually powered by high-torque diesel-electric motors but, in response to environmental concerns, more and more rigs are using engines powered by compressed or even liquefied natural gas (both must be trucked in, however, with the potential for damage to local roads).

In some cases, lateral wells in shale may also be drilled using directional drilling technology originally developed in the 1980s by Mitchell Energy of The Woodlands, TX with some assistance from DOE's National Energy Technology Labs near Pittsburgh[28]. The lateral penetrates the hydrocarbon-bearing formation and provides more routes for product to enter the well. In the case of dry gas wells with no production of water or gas liquids, the lateral may be close to horizontal. In cases where liquids drainage must be managed or if the formation itself is not horizontal (common in basin structures), the lateral may be inclined to the horizontal. Laterals are typically 10-20,000 ft. in length but a few have been as long as 40,000 ft. Once the well is drilled (or more usually concurrently with drilling) all of the well is cased throughout in one or more layers of high-strength steel tubing (to withstand the overburden pressure) that are sealed to one another and to the well wall with cements developed for the purpose. This is especially true if the well passes through an aquifer, as most do, or through a part of the formation that may have low strength and therefore might collapse. Because the tubing must withstand fracking pressures (especially the longitudinal stresses set up in the vertical bore), it is also normally constructed of high-strength steel and joints between tubing segments are strengthened and may even be welded, although that is rare. Nevertheless, one of the most common reasons for well failures, usually during fracking when the internal pressure is high, is tube joint failure or even tubing failure. In severe cases this can result in the ejection of a section of tubing from the well along with the "Christmas Tree", the complex arrangement of tubing at the top of the well that is designed to handle the produced gas or oil and that usually includes the blowout preventer(s). Very little fluid leaks under these circumstances because the fracking pumps immediately detect the pressure drop and shut down.

Fracking of deep and/or directional wells is most often done with several hundred thousand to several million gallons of high-pressure (up to ~15,000 psig) water that contains about 10-20% of sharp sand or an equivalent ceramic with controlled mesh size and about 0.5% of five to ten chemicals that are used to promote flow both into and subsequently out of the fractured formation. The list of chemicals includes hydrochloric acid to dissolve minerals and initiate cracks in the formation. Biocides such as glutaraldehyde or quaternary ammonium chloride may be added to eliminate bacteria that produce corrosive byproducts. Choline chloride, tetramethyl ammonium chloride, or sodium chloride may be added as clay stabilizers. Corrosion inhibitors such as isopropanol, methanol, formic acid, or acetaldehyde may be dissolved in the water, along with friction reducing compounds, for example polyacrylamide. In some cases, scale inhibitors are mixed in, for example acrylamide/sodium acrylate copolymer, sodium polycarboxylate (commonly used in dishwasher detergents), or phosphoric acid salt. Surfactants such as lauryl sulfate are added to prevent emulsion formation, and in some cases, the surfactant is dispersed in a carrier fluid such as isopropyl alcohol. To adjust the pH, sodium or potassium hydroxide or carbonate is used. All of these, of course, are present at very low levels. Table 1 gives an overview of typical fracking fluid components. The sand or ceramic acts as a so-called "proppant" and helps to prop the cracks open. Sometimes, more complex proppants are used - rigid fibers, for example, or ceramic particles of controlled size and geometry. Calcined bauxite is common since it has very high crushing strength.

To facilitate fracking, the steel casing that is inserted into the well is typically penetrated with pre-placed explosive charges (shaped charges are common). The fracking mixture flows into the formation through the resulting holes, and these holes subsequently provide a route for product flow back into the production tubing. In deep wells with long laterals, the fracking may be done in stages, beginning at the far end of the well bore, with the later stages separated by a temporary plug to isolate the section being fracked. Once each section is fracked, the plug is removed and the same fracking solution may be used for the next segment.

Once the well is fracked, the fracking water that can be recovered (usually between 25 and 75% of the total used) is pumped out of the well or (if gas flows from the well under sufficient pressure) flows out of the well along with the produced gas. Wells in oil-bearing formations, especially those involving shale, are much more likely to require pumping. The 'lost water' disappears into areas around the fracked formation or enters deep aquifers in which it is diluted and eventually lost. At the concentrations typically used for HF, most of the chemicals employed today are not considered toxic or carcinogenic. However, not much is known about how these chemicals interact with the various constituents of the formations deep underground, and it is conceivable that under certain conditions new compounds, some of them not benign, may be formed.

TABLE 1: Typical Fracking Fluid Components

NOTE: Not all components may be used in every well

Component	Concentration	Reason	Common Uses
Fresh Water	80.5%	Solvent or carrier	Drinking
Sand or ceramic	10-20%	Proppant – keeps fractures open to permit oil/gas flow	Playground sand, drinking water filtration
Acids (usually HCl)	0.12%	Helps dissolve minerals, initiate fractures in rock	Swimming pool cleaner
Petroleum Distillates	0.088%	Dissolves polymers, reduces friction	Mineral Oil – laxative, makeup remover, candy
Isopropanol	0.081%	Viscosity increaser	Antiperspirant, glass cleaner, first aid antiseptic
Potassium chloride	0.06%	Creates brine carrier fluid	Low-sodium table salt substitute
Guar gum	0.056%	Water thickener for sand suspension	Thickener used in cosmetics, baked goods, ice cream…..
Ethylene Glycol	0.043%	Prevents scale deposits in pipe(s)	Automotive antifreeze, household cleansers, deicer, caulk.
Sodium or Potassium Carbonate	0.011%	Improves the effectiveness of other components such as cross-linkers	Washing detergents, soaps, water softeners, glass, ceramics
Sodium chloride	0.01%	Stabilizes gel polymer chains	Table salt
Polyacrylamide	0.009%	Minimizes friction between fluid and pipe	Water treatment, soil conditioner
Ammonium bisulfite	0.008%	Oxygen remover to prevent pipe corrosion	Cosmetics, food and beverage processing, water treatment
Borate salts	0.007%	Maintains fluid viscosity as T increases	Laundry detergents, hand soaps, cosmetics
Citric acid	0.004%	Prevents precipitation of metal oxides	Food additive, foods and beverages, lemon juice
N,N-dimethyl formamide	0.002%	Prevents pipe corrosion	Pharmaceuticals, acrylic fibers, plastics
Glutaraldehyde	0.001%	Eliminates bacteria from produced water	Disinfectant, sterilizer for medical or dental equipment

3.1.2 Water Acquisition and Disposal

The so-called "flowback water" presents a disposal problem. Not only does it contain the generally harmless chemicals that were introduced with it, it also may contain chemicals picked up from the formation during fracking. It also contains rock debris from the drilling process, some of which may be slightly but not dangerously radioactive in cases where the sediments that formed some of the layers in the shale contained ^{238}uranium or even small amounts of ^{226}radium. It also contains drilling mud (mostly insoluble barium sulfate). Usually the flowback water is stored temporarily in closed tanks or open lagoons (tanks have the advantage that any methane and other gases emitted can be collected and used; open lagoons are not allowed in Michigan). Technologies are being developed that will allow the processing of this water stream and prepare it for legal disposal in injection wells or, more likely, re-use, with the solids residue going to an approved landfill[29].

Most formations also contain water prior to fracking. This especially true of the Antrim (MI) and New Albany (IL, IN, KY) shales, which must almost always be pumped dry after drilling and fracking before gas can be produced (the Antrim shale contains no significant oil and C_2-C_6 gas liquids are found in commercial quantities only in the eastern extremity of the onshore part of the shale—it continues under Lake Huron). In many cases, this water may be highly saline and also presents a disposal problem. Interestingly, in the Antrim, and also in the geologically similar New Albany shales in Indiana, Illinois and Kentucky, millions of years of rain and glacial water ('meteoric water') seem to have greatly diluted the water in the shale and effectively pushed the high salinity water down to lower levels. As a result, the produced water is more easily disposed of but may still be too saline for conventional water treatment plants. In Michigan, in the Antrim and the northern Niagaran Reef structures, the primary dissolved solid is sodium chloride but significant concentrations of calcium and magnesium ions are also present, along with barium and strontium.

Antrim fracking requires only a relatively small amount of water since the most commonly-used fracking technology is nitrogen foam fracking. In the much deeper Collingwood and Utica shales and especially in the A-1 Carbonate that overlies them, it appears that deep vertical wells accompanied by extensive and possibly multiple lateral wells are required to access enough gas to justify drilling. This leads to a substantial need for water. In all such situations, the greater volumes used (and hence also produced as flowback water) are becoming a cause for local concern. In addition to disposal and spillage issues (in the latter case, especially of concentrated chemicals on the well pad), there is a concern that sourcing such "large" amounts of water could have an impact on the sustainability of local water resources. This is a somewhat misplaced concern since many other much larger uses of the same water exist—crop irrigation, for example. However, as mentioned previously, flowback water in Michigan is disposed of via deep well injection. Of course, concerns over water are far more severe in the western U.S. where water is less readily available than in Michigan.

Water Treatment

Several efforts are being made to develop a treatment methodology for fracking flowback water. The primary challenge in doing so is the extreme variability in the chemical composition of the flowback stream, mostly due to the wide range of possible compounds that is picked up from the formation. High salinity, organics and total dissolved solids are the greatest problems. While the ingoing fracking solution consists of 90% water with up to 20% of sand or other inert proppant and about 0.5% of chemicals that, for the most part, are identical to those used in many other above-ground applications, the return water has an unpredictable amount of salinity and organic content that can vary quite widely, even among neighboring wells (the proppant mostly remains in the formation). The best that can be expected is a generic treatment basic water treatment system that must be "tweaked" for every individual case with the objective of producing re-usable fracking water.

3.1.3 Well Completion Issues

The often-postulated percolation upward of fracking water used in deep, long lateral well extensions to contaminate drinking water aquifers near the surface through the intervening impermeable rock formations is highly unlikely and has never reliably been shown to have occurred. There is a lot of impervious rock between a deep directional (lateral) well and the surface. Leakage, even if some of the intervening rock is fissured vertically, is geologically very unlikely. Other routes, however unlikely, are remotely possible. These include leakage via neighboring wells that are too close to the active well (a problem that can easily be avoided). In an early 2012 case in Alberta, a vertical well was inexplicably drilled and fracked closer than regulations (and common knowledge) allowed to an existing well in the same formation and fracking water at high pressure moved horizontally through the formation made its way up the existing well which was not designed for the fracking pressure used. Fortunately, damage was minimal and no water supplies were affected (Wilson JR, personal observation).

Faulty well drilling or (more commonly) well completion issues are a different issue. The following schematic (Figure 5) shows a typical drilling rig configuration with a list of major components, using the terminology most common in the industry. It is important to understand that almost all wells, whether or not they are intended for fracking, are drilled in this way—included any directional segment. The drilling rig is then removed and fracking, which requires different equipment, is begun. However, while the rig is in place, a wide range of equipment, including casings of various sizes to production tubing and sealing cement is placed in the well bore along with various centralizing spacers, packers, and other devices that assist in subsequent stabilization of the well during and after fracking. While the American Petroleum Institute attempts to set standards to be followed by the industry, there is a wide variety of different practices in use. Each well can present different challenges and may require a different approach or set of procedures or equipment. Thus, drilling and fracking is far from the simple process that many seem to believe.

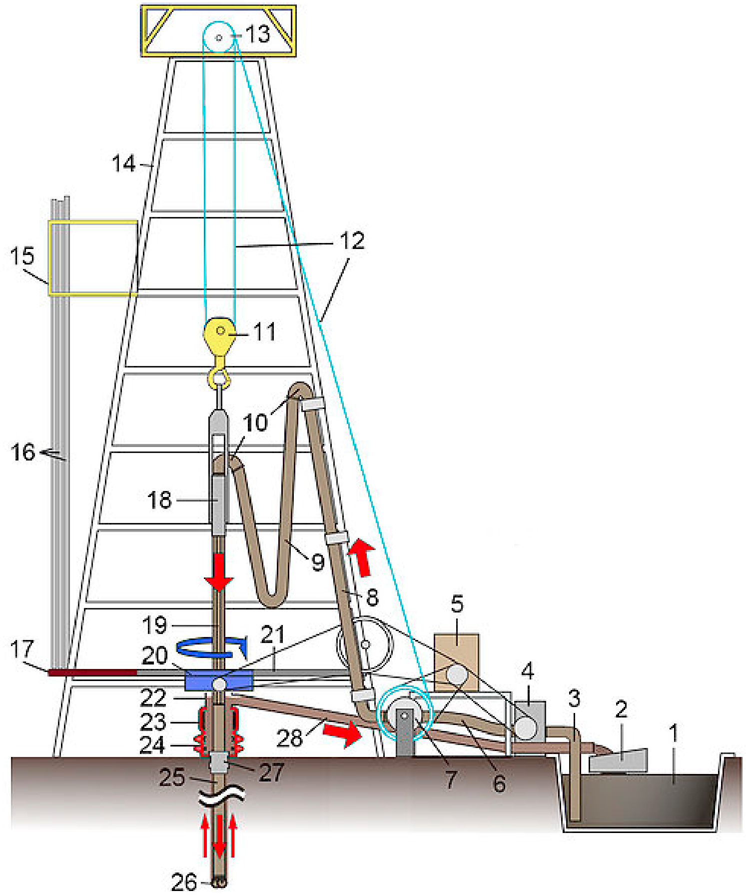
An added factor is that much of the work is not automated and is still done by people, and people tend to make errors, especially under the difficult working conditions common on a drilling rig, even when they have been highly trained. This is far less of a problem in the industry than it was, say, two decades ago, and catastrophic blowouts and spills are now very, very rare given that some 35,000-40,000 wells are drilled and fracked in the U.S. alone every year—for a total of well over 1.25 million to date. Changes in equipment design have served to minimize problems, but mistakes still occur.

As noted earlier, drinking water aquifers near the surface are protected by a series of layers of high strength steel tubing (casing) and specially formulated cement. Once the cement has set, it should be impossible, even during the extreme pressures applied during fracking, for any of the fracking solution or "slickwater" to reach the aquifer. However, problems can occur in well construction. This is usually the result of faulty materials, faulty down-hole equipment, faulty casing joints or welding, faulty materials or (much less often than was once the case) faulty cementing. The following table shows the frequency of occurrence of the most common errors in well construction. Note that "poor cement" is a minor offender. Note also that Michigan has been relatively free of the problems listed.

The establishment of a reliable barrier against gas leakage is critical to all gas wells, whether or not they are subjected to HF. Methane is a major global warming agent during its relatively long lifetime in the atmosphere. Cement is the major barrier used, and historically this was often a source of gas leaks at the wellhead or into drinking water aquifers. Changes in cement formulation and methods of use have greatly reduced the problem, but it still occurs occasionally, especially, for some reason, in Canada. Gas is distributed nation-wide through a very complex pipeline system which presents numerous opportunities for leaks. Diligent work over many years has reduced these to less than 2% of the gas produced in some cases but there is clearly room for further improvement[30].

The simplified schematics on the following pages show the wellhead equipment that is typically required for a well producing oil

Figure 5: Schematic of an oil or gas drilling rig[31,32]



1. Mud Tank
2. Shale shakers
3. Suction line (mud pump)
4. Mud pump
5. Motor or power source
6. Vibrating hose
7. Draw-works
8. Standpipe
9. Kelly hose
10. Goose-neck
11. Traveling block
12. Drill line
13. Crown block
14. Derrick
15. Monkey board
16. Stand (of drill pipe)
17. Pipe rack (floor)
18. Swivel (On newer rigs this may be replaced by a top drive)
19. Kelly drive
20. Rotary table
21. Drill floor
22. Bell nipple
23. Blowout preventer (BOP) Annular type
24. Blowout preventer (BOP) Pipe ram & blind ram
25. Drill string
26. Drill bit
27. Casing head or Wellhead
28. Flow line

Figure 6: Typical pump jack for oil[33]

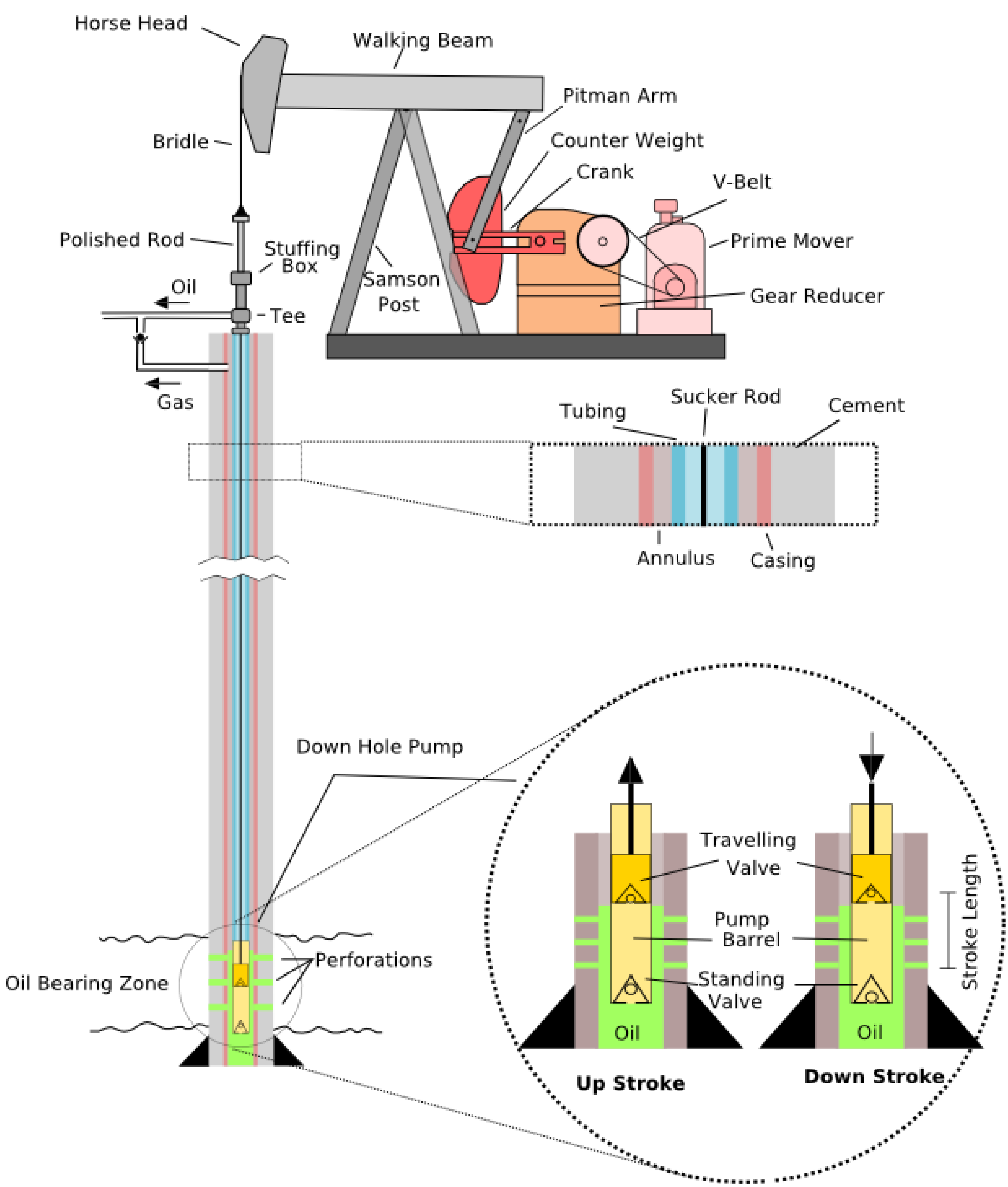


TABLE 2: Results of a Survey of Blowout Modes, 1960 to 1996 (36 years), Louisiana + Texas + Offshore Barrier Problems

Primary Barrier	# BOs	Comments
Swabbing	158	One of several methods of 'liquids unloading' a well. A plunger that seals to the wall of the production tubing is used to lift water or other fluids out of the well. Mishandling of this often leads to costly loss of well control (LWC).
Low drilling fluid weight	50	Drilling fluid may have too much water or not enough high-density components such as barium sulfate (barites), thus failing to hold gas down in the well and/or resulting in lost fluids circulation.
Drilling break/unexpectedly high pressure	45	Very common, normally handled by blowout preventers. This may have triggered BP's Macondo disaster where two BOPs in series apparently malfunctioned. (BOP = Blowout Preventer)
Formation Breakdown/Lost Circulation	43	May lead to complete loss of well or at least the directional section.
Wellhead Failure	40	More common than it should be. Leaking fluids should be controlled by blowout preventers, now more reliable than during this survey period.
Trapped/Expanding Gas	40	May get past drilling fluid but should be stopped by BOP at wellhead. Older BOPs were often unreliable.
Gas Cut Drilling Fluid	33	Effectively results in loss of drilling fluid density and hence blowout – should be prevented by BOP.
Christmas Tree Failure	23	Usually due to errors in fabrication such as defective welds or valves. Stopped by actuation of wellhead BOP.
While Cement Setting	20	Caused by failure to allow enough time to set – gas (usually) gets by cement seal while it is still in slurry form or 'plastic' – establishes 'channels' that are difficult to fill or plug.
Unknown Reason	19	Usually a blowout resulting from a cascade of events of which first step is unknown. In some cases, even after detailed analysis, a reason may not be identified.
Poor Cement	16	Cement formulations have improved greatly since 1996 and "poor cement" problems are now very rare but still occur occasionally where inexperienced or cost-cutting subcontractors are involved.
Tubing Leak	15	Once common due to poor materials, manufacturing and joint design, now rare.
Tubing Burst	10	See above for "Tubing Leak". Now extremely rare.
Tubing Plug Failure	9	Can still occur, usually because of poor installation. Plugs are used to isolate sections of tubing during perforation and fracking. Can be difficult to 'fish' out.
Packer Leakage	6	Caused by improperly designed packer or improper installation. Now very rare.
Annular Losses	6	A catch-all for gas leakages past cement that should fill and seal the annulus. Usually the result of a poor cement job. Still occurs, albeit rarely, in the U.S.
Uncertain Reservoir Depth/ Pressure	6	Inexcusable - there is no reason why this information should not be available and used in process design.

from a well not producing under its own pressure (as is the case with almost all *shale* oil wells) with gas as a by-product[31,32].

In the case of gas-only production, there is no walking-beam pump and production comes from the natural gas pressure in the well. In all cases, there are typically two additional casing runs at the top of the hole that are not shown here—the *conductor casing* which is wide and only very short and is designed to provide a foundation for subsequent well casing; and a longer run of casing, separated from the conductor casing by a cement seal and designed to separate the well from any aquifers through which it passes. This lining extends below the lowest aquifer used for drinking water. The main well casing (shown in pink) is separated from the bore wall (and any other wider casings) with cement (shown as the "annulus").

Although rare, problems associated with fracking were more often than not due to human error in the selection and operation of down-hole equipment (spacers, centralizers, packers, tubing joints, blowout preventers) and, of course, a wide variety of well maintenance and workover operations. The well and its hardware must be built for the specific fracking operation intended (with an appropriate margin of error) and must therefore, in most cases, withstand high internal pressures without failure.

Table 2 lists some of the failures that occurred over a 36-year period between 1960 and 1996 in wells drilled and in most (but not all) cases fracked in Louisiana, Texas and nearby shallow-water offshore locations. While few of these failures would occur today due to improved personnel training, better-designed procedures, improved equipment, and better technology/materials, they emphasize the need to maintain constant vigilance over these issues if disasters such as the recent Deep-Water Horizon/ Macondo blowout (BO) in the Gulf of Mexico are to be avoided. Human errors are not limited to those listed. Very often, especially

TABLE 2 (Continued): Results of a Survey of Blowout Modes, 1960 to 1996 (36 years), Louisiana + Texas + Offshore Barrier Problems

Secondary Barrier	# BOs	Comments
Failed to Close BOP	78	Can be mechanical problem or, more often, human error
BOP Rams not seated	14	Due to fouling, wear, corrosion…..
Unloaded to quickly	13	Too-quick liquids unloading may not provide operator time to close off well or operate BOP. One of the dangers of the old open-well liquids unloading practice.
DC/Kelly/TJ/WL (see Figure 5) stuck in BOP	5	Any hardware still in the BOP will prevent closure.
BOP Failed After Closure	66	Poor selection of BOP for the pressures involved, poor BOP construction, poor manual operation of BOP. Now very rare.
BOP not in place.	43	Inexcusable effort to cut costs.
Fracture at Casing Shoe	38	Can permit annular gas leakage. Rare, but still occurs.
Casing Leakage	23	Once common due to poor materials, manufacturing or joint design, now very rare.
Diverter Activation	19	Used to divert emergency fluid flows away from the drilling rig in cases where the well bore cannot be shut in until more permanent remedial action can be taken.
String Safety Valve Failed	19	Drill string safety valve is designed to control pressure kicks (a form of annular flow) during drilling. Failure results in gas leakage unless the BOP can be closed. Now rare.
Formation Breakdown/Lost Circulation	15	Serious, can result in loss and subsequent plugging of well.
String Failure	13	A major problem because the lost (lower) part of the string must be fished out of the hole. Alternatively, the original hole may be plugged and a new one drilled. Both costly.
Casing Valve Failed	11	Now almost unheard of due to improved design and materials.
Wellhead Seal Failed	10	Usually a cement failure, now rare.
Failed to Operate Diverter	7	Usually an operator failure in an undisciplined "every man for himself" culture. Very rare now.
Christmas Tree Failed	7	Usually due to errors in fabrication such as defective welds. Stopped by actuation of wellhead BOP. Very rare as a secondary failure.
Diverter Failure	17	More common 20 years ago, now very rare.

in deep drilling (10,000 ft. or more), little is known about the shale formation that is to be accessed or how it varies in the directions parallel to the plane of the shale that will be directionally drilled. This lack of knowledge can lead to costly problems such as dry wells or difficulties in accessing sufficient gas, gas liquids or oil to justify the very high cost of drilling long laterals.

The following record is taken from the work of Skalle and Podio[34]. The comments are those of the present writers, based on some 40 years of experience. The list will provide the reader with some evidence that well-drilling is not a simple operation. In fact, it is technically very complex (and costly) with numerous opportunities for human error and equipment failure. Fortunately, most of these have been overcome by diligent engineering studies and steadily improving technology, materials and construction methods and, above all, operator training.

As noted earlier, a short but sturdy conductor casing is common to almost all well installations. This provides a foundation for the construction of the rest of the well. Thus, in addition to the conductor casing, there is a surface casing whose primary "duty" is to protect any surface aquifer, especially one used for drinking water. It must therefore extend below the deepest aquifer of interest—usually only a few hundred feet. The well is drilled initially at a somewhat larger diameter to accommodate it. This is then followed by the main well casing, which extends the full length of the well. All of the conductor casing, the surface casing, the well bore casing and the production tubing (shown in blue in the preceding figure) are separated from one another and from the bore hole by an annulus filled with cement sealing materials. Many types of cements are used, each designed for a specific set of down-hole conditions, so it is important that these conditions be known before the cement is selected. For example, some cement contains special ingredients such as latex to enhance bore and annulus sealing but cannot be used at the greatly elevated down-hole temperatures (>200°C) found in a few areas[35].

For some reason, many shallow- to moderate-depth gas wells in Canada (Alberta and Saskatchewan) and in the northern states of the U.S. (e.g., ND, MT) suffer from a gas migration problem. The gas from the well (whether fracked or not) somehow flows up the cement-sealed annulus and either enters an aquifer or leaks into the atmosphere. Most are not serious, but they indicate a problem with cement formulation or installation. All well operators and their subcontractors are required to adhere to API standards[36], so the frequent failures are a mystery.

These errors in what is part of well completion are still of concern but can be prevented by good engineering and wellhead design accompanied by thorough inspection. It is more common for gas, rather than fracking solution, to leak past the casing and cement and enter an aquifer or reach the surface simply because the low-viscosity gas finds an easier path than the much higher viscosity water. This reportedly occurred recently due to a casing failure in a well just SW of Traverse City, MI[37]. Hal Fitch, Director of Oil, Gas, and Minerals, for the Michigan Department of Environmental Quality (DEQ) has stated that no fluid spilled and there was no damage done to the environment as a result of this incident (Hal Fitch, MDEQ, pers. comm.). There have been a few reports of gas contamination but so far no *confirmed* reports of fracking water contamination of drinking water aquifers. As noted in our earlier report, contamination of water wells by *naturally-occurring* gas is common in many areas of the U.S. and Canada and is easily dealt with except in cases when the gas contains large amounts of sulfur (in the form of H_2S). Gas in water can occur when the water well is unintentionally drilled into a gas-bearing stratum such as coal or a non-commercial shale bed. Therefore, it is considered prudent to collect baseline data before drilling for oil and gas begins, to assess to what extent the existing water wells are contaminated by naturally-occurring gas.

Baseline data collection requires great care to avoid misleading contamination of the source water. For example, the EPA drilled two wells in Pavillion, a small town in Fremont County, Wyoming. The objective was to assess whether hydraulic fracturing had contaminated drinking well water in the vicinity of the town. Unfortunately, as was subsequently pointed out by the USGS and many others, the EPA apparently knew little of water well drilling and contaminated the samples obtained with drilling fluid, well drilling residue, and hydrocarbons. They also used drill pipe and well casing that was not rust-resistant (stainless steel is normally required, especially in test wells). In that area, as in most of Wyoming, natural gas occurs very commonly in well water, perhaps derived from coal beds; thus the presence of gas does not indicate contamination by hydraulic fracking. The EPA results were therefore inconclusive[38-394041].

3.2 Well Stimulation Technologies Used In Michigan

3.2.1 Directional Drilling

Recently, there has been only very limited activity in terms of directionally drilled wells in Michigan with the exception of a few exploratory wells drilled in deep formations such as the A-1 and A-2 Carbonates and the Collingwood/Utica shales beneath them[ii]. Many of the wells in the Antrim formation are vertical since the shale there is naturally fractured horizontally, and directional drilling would not offer much advantage. Historically, Michigan was a pioneer in directionally drilled "slant holes" and in the development of micro-resistivity dipmeter analysis and side-tracking of wells targeting the Brown Niagaran (now referred to as the Guelph Dolomite/Ruff Formation) pinnacle reef formation. Today, one can still find hundreds of such directionally drilled boreholes in these areas, some of them made for formation drainage purposes.

Since 2008, Michigan's DEQ has issued more than 50 active permits for "high volume" (those using more than 100,000 gallons of hydraulic fracturing fluid) hydraulically fractured wells, and more than half a dozen applications are pending[42]. Most have been drilled (or will be drilled) in the A-1/A-2 Cs and Collingwood, Utica, generally in the northern LP and also in the Black River/Van Wert shale in Hillsdale County on the Ohio Border (most of this shale formation lies in Ohio). However, at the time of this writing, there was only one drilling rig in Michigan, and it is not clear if it is currently active.

So far, drilling in Michigan's deep shales and carbonate formations has produced disappointing results, but these are early days (Encana Corporation, pers. comm.). A high proportion of the wells drilled in the Collingwood shale, once considered so promising that it led to the sale of a record number of leases at record prices on state land in 2010, have been dry or have been permanently or temporarily abandoned. The high cost of drilling these wells is not compatible with the current low price for the dry gas that most of them produce. Nevertheless, a handful of wells in the Collingwood are producing gas and at least one has reported a show of oil[43]. Oil has also been found in the A-1 Carbonate, but that well is recorded as shut-in, presumably indicating that it was not commercial.

Almost 10,000 wells, almost all of them vertical, have been drilled in the Antrim shale and almost all have been fracked. While little or no new drilling is possible, workovers of existing wells are common. Like the original well completions, this usually involves fracking, sometimes with gelled nitrogen foam, less often with slickwater, to

[ii] Note that while the Collingwood lies well below the A-1 and A-2 carbonate formations in Michigan, it surfaces to form the shore of southeastern Lake Huron in Ontario (before it disappears under the Blue Mountain Shale). It would be interesting to have access to the details of the geology of the Collingwood under Lake Huron.

stimulate the productivity of the well. This method has been quite successful, and the Antrim shale still continues to produce significant amounts of gas[44]. As the Antrim field as a whole declines, the middle portion, mostly in Montmorency and Otsego Counties, produces an increasing amount of CO_2. The current level in the gas being produced is 30-35% by volume. This CO_2 is separated from the methane and any other hydrocarbon gases that may be present and is then (a) released to atmosphere (no longer considered a good practice), (b) sequestered underground, often in depleted gas wells or (c) used for enhanced oil recovery (EOR). Several trials of CO2-induced EOR have been run in the Niagaran Reefs, apparently with good success for a first attempt and, as a result, more oil may still be recovered from this already quite prolific formation[45].

The northern trend of the Niagaran reef crosses and underlies the Antrim shale and is still a major producer, depending on where drilled, of gas, water or oil. It has been Michigan's greatest contributor of energy products since its discovery in the late 1960s and appears likely to continue to be a major factor for some years to come. Its geology is very complex; we leave that discussion to others in this series of reports.

The gas found in the Antrim formation, like that in Ontario's Kettle Point extension of the Antrim and also the New Albany shale in Indiana/Illinois/Kentucky is known to be biogenic in origin—i.e., it is derived (and may still be being derived) from anaerobic bacterial action on organic matter deposited long ago when the shales were formed. Methanogenesis in all of these cases has apparently been aided by the "washing" of the formation by glacier and rain/snow-derived meteoric water which has pushed what were once high salt levels down to greater depths[46]. This has prevented the inhibition of biological action by what would otherwise have been high salinity. It may also explain the very high water content of these shales. Many other shales appear to have produced methane by thermal action (thermogenesis)—i.e., by intense heating of the organic matter, usually through geothermal activity.

The source of most of the organic matter in most shale appears to have been algae that were carried into relatively quiescent areas by the flow of streams originating from bodies of fresh water (most shale was apparently formed in saline waters, presumably on estuaries or sea beds). Other contributions were possibly made by small vegetable particles such as leaves or roots ground up by the water flow over stones or sand. Whether the methane is biogenic or thermogenic in origin then was determined by the subsequent history of the deposits over a period of many million years, during which layers of mineral sediment and clays were often also deposited.

Many of the large number of other oilfields in Michigan have been important but relatively small and shallow. Most if not all are now in decline or have been plugged but few have yet been subjected to the aggressive EOR methods that have become common in other states such as Texas. This means that most (up to 90% in some areas but an average of 60-65%) of Michigan's original *oil* (but not gas) remains in the ground. A field-by-field study to determine the probable effectiveness of EOR technology seems long overdue. While some of the 14,542 oil wells and 13,269 gas wells drilled in Michigan (not to mention a few of the 22,067 dry holes) as of September 2012 were subjected to fracking[47], it seems likely that not only directional drilling from existing producing oil wells but also HF workovers, where allowed by the MDEQ, could be a source of additional oil.

Gas fields do not suffer as much from this limitation. Provided that a formation can retain enough porosity and does not become water-flooded, gas production will continue until the fall in well pressure makes the well uneconomical to operate. As mentioned earlier, vacuum extraction may obtain a little more gas but is frowned on in most jurisdictions

3.3 Current Oil and Gas Industry Practices in Michigan

3.3.1 Current Practices

In general, Michigan oil companies have not been technology leaders in oil and gas exploration and production. They have followed much the same conservative (but safe and usually environmentally sound) pathway of many other mid-range producing states such as Ohio and Indiana. This may change with the recent discovery of probable gas and perhaps oil in formations such as the A-1 and A-2 Carbonates and perhaps even the deeper Collingwood and Utica shales (including the Utica in Ohio), but little appears to be known about these on a micro-geological scale and they will be costly to explore and develop based on the few results obtained so far. Directional drilling and fracking *will* be required, based on what is known of the limited permeability of these formations and the laterals will probably have to be of unusual length to ensure reasonable gas production. Even with substantial laterals, it still may not be possible to open pathways to enough gas or gas liquids to make wells in these formations economically viable. Significantly higher gas prices may be needed. This is discussed further in the next section.

So far, there has been very little experience with the A-1, A-2, or the Collingwood and Utica shales. Encana, Chevron Michigan, Merit Energy and several others all have permits to drill in Michigan's Collingwood formation, but there have been few holes completed to date and, as previously noted, there is now only one rig in total drilling (potentially) in the state. Given the limited experience to date with the Collingwood, most of it negative or neutral, it seems unlikely that any company will establish an aggressive drilling

TABLE 3: Challenges Encountered in Well Drilling and Completion

Key Variable	Comments and Notes
Shale	Shale types vary widely and are often surprisingly heterogeneous. There is often more than one shale layer interspersed with other rocks such as sandstone, limestone or clays. Black shales are usually high in Total Organic Carbon (TOC) while white or grey shales are often high in limestone and/or quartz but may nevertheless contain natural gas or even gas liquids (which may have migrated from elsewhere). Shale gas is typically found in fine-grained reservoir rocks in which the gas is self-sourced from the TOC present. Some of the gas is stored in the adsorbed state, predominantly in the organic fraction.
Total Organic Carbon (TOC)	Can be obtained by wireline logs but the data are often not an accurate representation of TOC. Confirmation is required by core sampling and analysis (costly!). TOC may vary widely in any shale bed, even over distances of a few feet. Organic geochemistry may not be a good indicator of formation prospects.
Mapping TOC in a Formation	Has the same limitation as TOC, above. Confirmation may require many exploratory drill holes – very costly in deep formations. Better methods of assessing formation potential are needed.
Wireline Logs	Only occasionally a good guide to organic content or formation prospects (see "TOC"). Results should be confirmed by other means.
Shale area	Shale beds are often highly variable, inconsistent, not always productive where expected, may have variable thickness, structure and TOC. This seems to be especially true of the Collingwood Shale.
Shale thickness	Will vary widely throughout a large shale bed such as the Collingwood. Productive shale may be present in multiple layers separated by non-oil (or gas)-bearing layers.
Geochemistry	Often unknown or very hard to determine. Even TOC history may not be clear (see below). Organic-rich layers may contain multiple minerals (quartz, alumina, aluminosilicates and carbonates) which make history obscure. Diagenesis (formation of sediments and conversion to sedimentary rocks) is usually clearer.
Maturity	Often unclear. Many gas shales, like the Antrim and Kettle Point, are relatively immature, contain biogenic methane (and may still be producing it) while others, even in the same formation may be thermogenic and/or much more mature. Thermal maturation structurally modifies the organic fraction, creating more macroporosity – and hence more adsorption sites. Presence of oil v. gas v gas liquids v. condensate determined by many factors including T, P, TOC and formation history.
Adsorbed Gas	Methane adsorbs preferentially in organic-rich shales, is often replaced by carbon dioxide (if present) as it is depleted by production (as in the central Antrim formation). Other organic and non-organic gas may compete for adsorption space, usually on the interior of pores. This can make determination of original gas in place (OGIP) difficult. In general desorption testing will indicate more gas than is actually adsorbed; the balance are probably free 'pore gases. OGIP = Free Gas + Adsorbed Gas + Solution Gas…..but still not clear what it means since OGIP is often seriously overestimated by testing.
Moisture	Complicates analysis of core samples, which must be dried first. Competes with methane, etc., for adsorption "space", may give spurious gas content results.
Free Gas	Most shale contains some non-adsorbed gas which may be trapped in closed pores until accessed by some form of fracking.
Gas Capacities (see also OGIP)	Often very difficult to determine precisely prior to actual production. Many promising wells are still a disappointment for this reason.
Solution Gas	Gas dissolved in liquids present (gas liquids, crude oil, condensate, water…..) that may be hard to determine prior to production.
Pressure	Usually, deep formations = high pressure due to overburden load above. Can be a problem during lateral drilling (due to well bore shape distortion) and in fracking deep laterals. May limit producibility.
Temperature	In geological time, may have had a major impact on, e.g., the conversion of TOC to gas, oil, etc. Higher temps tend to favor oil production, but not always.
Producibility	Some "tight" shale formations (as well as sandstones, coal beds, etc.) may be non-viable economically despite promising test data. The causative factors are those listed below. Such wells may initially produce strongly immediately after fracking but production soon declines. The problem? Poor access to the contained gas.
Permeability	This and the next 'challenge', porosity, go together. Permeability in rock is extremely difficult to measure precisely and as a result permeability data are often wildly erroneous. Permeability is highly dependent on porosity and whether pores are closed or open.

Porosity	Porosity of rock varies very widely. Pore sizes are generally larger in oil-bearing formations. If only closed porosity is present (as in a closed –cell urethane foam) this has a strongly negative effect on permeability. If partially interconnected pores are present, measured permeability may be much higher since it does not have to depend as much on slow diffusion through the formation rock. "Tight" reservoirs may be very porous (in terms of pore count) but may still be very unproductive if no way can be found to connect or access the pores. The pores typically contain some free gas and rather more adsorbed gas. The amount of adsorbed gas depends on the local pressure, temperature and TOC – a higher temperature results in less adsorbed gas. But if the pore is closed, the gas cannot be recovered. **NOTE:** • Porosity measurements using skeletal density measured by helium are always too high. • With other gases, correction for sorption is mandatory • Correction for **pore compressibility** is essential All in all, permeability and porosity are not easily quantified.
Sedimentology	Shales are initially formed by sedimentation, but are almost always later modified by temperature and pressure and sometimes by complex geochemistry. The organic matter is typically derived from algae and small plant particles and is the primary source of oil and/or gas in the shale. Some shallow shale can lose some or all of its organic matter by conversion to methane and seepage into the atmosphere. Others, like Michigan's Collingwood shale, apparently have a much more complex history and have become very deeply buried by further sedimentation and subsequent geological action. The porosity, and hence permeability of these shales is probably established during these early formative processes. If the shale contains moisture or even free water containing dissolved species, this can materially alter its physical characteristics.
Silica Content; Alumina Content CaO Content	Most shale contains fairly high levels of silica, sometimes as quartz, and variable amounts of alumina and other oxides. In general, shales with high silica (70-80%) and low alumina (5-7%) exhibit relatively large pore sizes (10,000-100,000 nanometers) in a coarse grain structure while those with higher alumina (10-20%) and lower silica (50-70%) have much smaller pore sizes (1-10 nanometers) in a fine grain structure. Gas contained in high alumina shale is therefore likely to be much more difficult to access. Calcium oxide appears to have little effect until it reaches high levels, as in carbonate rock.
Diagenesis	The history of formation of the shale or other gas/oil-bearing rock from the original sediments is important in determining its ability to deliver the gas or oil to the operator, but relatively little is known of the relationship between diagenesis and well productivity other than the relationships described above. Porosity (above) decreases with diagenesis and effective stress due to compaction.
Fracturing	The purpose of formation fracturing, however it is done, is to gain access to more of the oil or gas contained in the formation. In formations with a coarse grain structure and large-scale porosity, such as the Antrim, this may be relatively easy but as the depth and hence pressure increases and especially in high-alumina formations with fine porosity, fracturing or 'fracking' may not achieve the desired result. Additionally, the original fracture orientation will depend on depth and hence pressure. In some formations, even when heavily fracked, only some 10% of the gas (and especially liquids) in place may be accessed, depending on the pore structure of the formation. Simply fracturing the rock into big pieces may have little effect. It may be necessary to reduce it to small-size particles, and that may not be practically achievable in deep wells. NOTE 1: microseismic data show what fracks, not what produces. NOTE 2: gas released from the rock matrix is strongly stress-dependent. In many reservoirs with widely-spaced fractures, the resulting low rate may be production-limiting.
More Challenges	Quantitative assessment of exploration targets. Determining intervals at which to frack or drill laterals. Predicting production rates. Predicting decline rates Predicting Estimated Ultimate Recoveries (EURs) If intervals of shale are thick, predicting drainage areas (spacing units)
Remaining Unknowns for most reservoirs.	What is the OGIP? Most data viewed as highly unreliable (see "adsorbed gas"). Production data seldom matches the OGIP number. What is the optimum interval to perforate and frack? Optimal Frack Design – e.g., # of stages, length of lateral? What is the drainage area/volume of each well? What is the recovery factor (percentage of oil or gas originally in place that is recovered)? What is the optimum well spacing and lateral spacing unit?

Radioactivity	Because uranium-238 is so widespread, albeit in very small concentrations, it accumulates in many sedimentary rocks – including shales. It has a half-life of 4.47 billion years and emits only harmless α-radiation. It is accompanied by about 1% of U-235 (half-life of 704 million years) and a minute amount of U-234. All are only very slightly radioactive and emit only weak α-radiation, which cannot penetrate even a thin paper tissue. Both flowback and produced water from some wells may be slightly radioactive or contain radioactive rock chips but are completely harmless. In a few black shale deposits, radium may also be found and typically shows up in the solid residue well from drilling, along with flowback water and drilling mud. The most common isotope is radium 226 which has a half-life of 1,600 years and emits only harmless α-radiation. Argonne Labs have determined that drilling residue containing uranium and radium can be landfilled if more than 10' deep and suitably capped with clay. See Ellis (this series) for additional information.
Flowback and Produced Water	Flowback water is very unpredictable. It may contain all or only part of the dilute chemical cocktail pumped into the well, plus a lot of inorganic and organic material picked up from the formation, some of which may be geologically very old. It also carries a heavy load of drilling mud and rock chips, some of which may be mildly (and harmlessly) radioactive – see above. Increasingly, flowback water is being reused after removal of solids and organics and at least some salinity. The flowback water leaving the well gradually transitions to produced water. The latter originates in the formation and may contain high salinity (although not generally in biogenic shales since the salinity interferes with the biological action; there the salinity has often been driven lower by meteoric water) and dissolved or suspended organics. Dry gas wells (those producing no gas liquids or condensate) often produce little or no water. Produced water from oil-rich wells can be very complex and difficult to treat. While common, deep well disposal should be approached with caution – there is too much chance of future and unpredictable movement of the waste 'plumes', perhaps over very long times
Methane Management	Methane is a major Global Warming agent (25-100X as effective as CO2). Every effort must be made not to release it into the atmosphere. This has already caused many changes in well management methods, especially during well drilling and completion and liquids unloading, but more is needed. The natural gas industry, which has historically lost 2-5% of its product between wellhead and point of use, is making major efforts, for economic as well as environmental reasons, to capture this lost gas, e.g., by using improved compressor seals, more welded joints (especially to mount instruments) and reduced flaring during plant upsets. Much more focus is needed on this issue.
Bacterial Activity	In shallow black shales in particular, methane is produced under anaerobic conditions by the action of certain bacteria on the organic matter (algae, for example) in the shale. The product is termed biogenic methane. In other shales, some methane may be produced by the thermal decomposition of the organic matter and is termed thermogenic methane. In black shales, some of the bacteria may survive and can be present in the flowback or produced water. The amounts are small and the bacteria are harmless. The same or similar bacteria are found in stagnant ponds and marshland, for example, where they also produce methane anaerobically from rotting vegetation in the mud at the bottom of the wetland.

program at present drilling and water costs and gas prices. The Collingwood requires wells of 10-12,000 ft. depth and laterals of roughly equal size unless some new method of fracking can be developed that will be more effective at fragmenting these very tight, low-porosity formations. Such wells can cost up to $10,000,000 if capital costs for gas refining and pipelines are included. At current refined gas spot prices of $3.50/1,000 cu. ft., over 3 billion cu. ft. of gas must be produced from the well just to break even. This means that it is doubtful that current gas prices will support the very high drilling cost. For the foreseeable future, we are likely to see only enough drilling to ensure lease retention in cases where agreements have a "use it or lose it" clause. This especially true in areas such as Kalkaska County where exploratory directional wells drilled to date have required far more water than is normal (an estimated 20 million gallons per well instead of the usual 5-7 million). The reason for this is not known but a large demand for water on this scale adds considerably to the cost to the well.

Meanwhile, the Antrim shale will continue to be addressed with stimulation methods such as additional fracking to ensure the recovery of the maximum possible amount of gas. Drilling will continue on the limited number of remaining inactive leases on the Niagaran Reef northern trend (which stretches between Manistee and Presque Isle Counties in the northern LP) with most of the focus being on oil except in Manistee County, where the reef has always been a moderately good gas producer. Additional attempts at enhanced oil recovery can be expected in the northern Niagaran Reef. The southern trend of the Niagaran Reef which runs roughly from western Oakland County through Livingston and Eaton Counties to the northern end of the Albion-Scipio trend in Calhoun County) is unlikely to generate much that is new absent an aggressive enhanced oil recovery program.

3.3.2 Permeability and Producibility

The challenge facing a would-be producer in formations like the A1 and A2 Carbonates and the underlying Collingwood is the very large number of variables that need to be understood and in some cases quantified before drilling can begin with a reasonable chance of economic success. If the formation to be drilled is two miles or more deep and if the laterals to be drilled cover in total a large area, the information that is required is very difficult to obtain. The following table attempts to summarize some of the key challenges facing the operator.

3.3.3 Methane Leakage

Another major issue for the entire natural gas industry is methane leakage. Successful efforts have been made for many years to gradually reduce the number of both large and small leaks in the vast and complex national distribution system because methane is a potent greenhouse gas. New-design pipeline compressors, once a major source, are now essentially leak-proof while instrumentation is improving through the use of welded joints and changes in design that return operating gases to the plant. Field monitoring of fracked gas well sites, which were once fairly major contributors to methane leaks due to careless handling of flowback water and practices such as open-well liquids unloading, now shows them to be comparable to conventional gas wells producing under reservoir pressure. While it is quite difficult to arrive at accurate estimates of methane emissions[48,49,50], field levels of methane reported for HF sites are now typically very low, in the range of 0.4—0.6 vol%[51]. The American Petroleum Institute (API) and the American Natural Gas Alliance (ANGA) recently issued a report on sources of methane emissions form natural gas production[52]. URS Corporation and the University of Texas at Austin recently issued a report on methane emission factors for selected processes and equipment used in the natural gas industry[53].

Wells for which the methane emitted during liquids unloading or collection of flowback water is captured and either used or included in the gas delivered to the well gathering system are increasingly referred to as "green completion" wells. Despite the fact that these practices have been used for several years by responsible operators, the development of "green completions" seems to be regarded as new. Regardless of its novelty, the practice is clearly one that should be adopted as widely as possible. As far as Michigan is concerned, the Utica/Collingwood and A1 formations are extremely tight and so far the drilling mud returned contained only small amounts of methane. However, in other locations, it is conceivable that the returned drilling mud and subsequent fracking flowback water may contain a higher proportion of methane. Regardless of the amount or source, it must be captured. In Michigan, all drilling operations must adhere to the requirement that during HVHF operations all hydraulic fracture fluid must be contained in pipelines and steel tanks; the methane that is separated from the liquids is sent by pipeline to the gathering system. Today's best practices for green well completions and testing would result in virtually no methane being flared or vented during the entire drilling, HVHF and testing and production operations.

3.3.4 Safety

Fracking, like oil or gas drilling, involves complex equipment and procedures operated by humans rather than being automated. Errors and accidents do occasionally occur, sometimes leading to the escape of fracking water or, much more often, gas into the atmosphere or into groundwater or drinking water aquifers, but such events have become increasingly rare as all of regulations and industry practices and personnel training have improved, especially over the past ten years. Most recent errors have involved faulty equipment or its faulty installation. A preliminary review of the safety record accumulated over more than 30 years of high-pressure deep well fracking (and a much longer period of all forms of fracking) indicates that so far fracking operations in Michigan have had a relatively good safety record, but a more thorough examination of documentation regarding safety related incidents in Michigan's oil and gas industry will be required before a definitive conclusion can be reached. With over 40,000 wells annually now being subjected to fracking in the U.S. alone and many more overseas, an occasional accident can be expected, just as it can for other industrial processes or the transportation sector, despite the extraordinary precautions and oversight that are now involved to ensure safety. People, however well trained, make mistakes.

3.4 Future Practices in Michigan

For many in the oil and gas industry, the oil and gas rush in Michigan is over and has been for several years. Most of the majors like Shell or Exxon have pulled out of the state and, at current gas prices, deep drilling in the Collingwood and Utica seems unlikely to be commercially viable, at least in the near term. Unfortunately, only a modest amount of gas liquids and, so far, no oil, seems to be associated with those formations, at least in Michigan; thus, unless there is something much deeper, it is unlikely that Michigan will follow North Dakota in discovering a highly productive Bakken-like formation. Most of the other oil and gas resources in the state are in decline (although oil production saw a burst of activity between early 2010 and August 2012), and the amount of those commodities produced by the state as a whole has been diminishing for 1-2 decades.

While exploration for oil and gas is, almost by definition, an expensive hit-or-miss process, even with the availability of modern exploration tools ('wildcatter' is still a relevant description of many current-day small drilling companies), Michigan now seems to be unlikely territory for a major success. The state was extensively and intensively explored in the middle years of the 20th Century and experienced many small to medium sized successes in both gas and oil. The last notable finds—all at least 40 years ago - were in the northern Niagaran Reefs and the Albion-Scipio trend. The Antrim Shale, while still producing, has been known for almost 70 years.

Given the extensive exploration history of the state and its now well understood geology, it seems very unlikely that Michigan will ever again see an oil or gas boom. The one possible exception, however apparently remote, is that significant recoverable gas will be found in the carbonate formations and the underlying Utica-Collingwood formation. These undoubtedly contain gas, gas liquids, and possibly oil (albeit high-kerogen oil in the southern extremity of the Collingwood which can currently be recovered only by expensive retorting technology) but, absent new technology developments, seem unlikely to be developed in the next decade or so.

The one possibility of enhancing production from Michigan *oil* wells seems to be enhanced oil recovery (EOR) technology that has so far been underutilized in the state. Only a limited experimental program with CO_2 injection has been tried (with notable success) in the northern Niagaran Reef. There appear to be many old wells in Michigan, some of them still producing with the help of walking beam pumps that could possibly benefit from an EOR program. While the CO_2 used for EOR in the northern Niagaran Reef came from the Antrim formation, that for southern wells would probably have to come from much-needed (but not yet implemented) power station CO_2 sequestration programs. This would be costly but should pay for itself in the greater amount of oil recovered and sold.

4.0 PRIORITIZED PATHWAYS FOR PHASE 2

The objective of Phase 2 will be to begin addressing some of the science and technology gaps relevant to fracking by conducting a series of experiments. The experimental approach is to develop a fundamental understanding of the adsorption and release of hydrocarbons, carbon dioxide, and other chemical species of interest. These experiments will be carried out both on well-defined model systems relevant for hydraulic fracking, as well as on actual shale samples that are representative for geological formations in Michigan and Ontario, including samples of "black shale" that may contain organic residues. The topics to be addressed include:

- Fundamental investigation of hydrocarbon adsorption/desorption from sand and shale samples
- Investigation of adsorption and surface reactions of typical individual fracking chemicals with sand and shale samples as a function of temperature and pressure.
- Comparative study of water-based and water-free fracking methods
- Study of the relationship between fracturing methods, fracture propagation and permeability in materials with different forms and distributions of gas-bearing porosity at high formation pressures

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