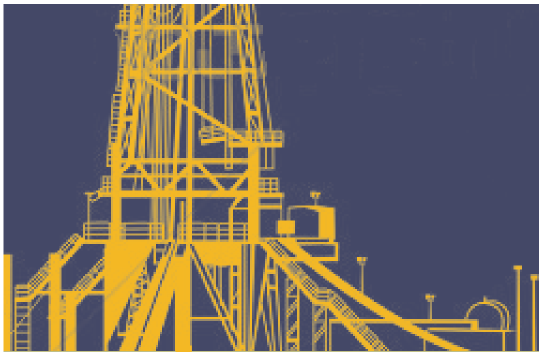


UNIVERSITY OF MICHIGAN

Geology/ Hydrogeology 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 a total of more than 100,000 gallons of hydraulic fracturing fluid. The reports indicate if the text is addressing oil and gas development in general, HF, or HVHF.

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.

Participating University of Michigan Units

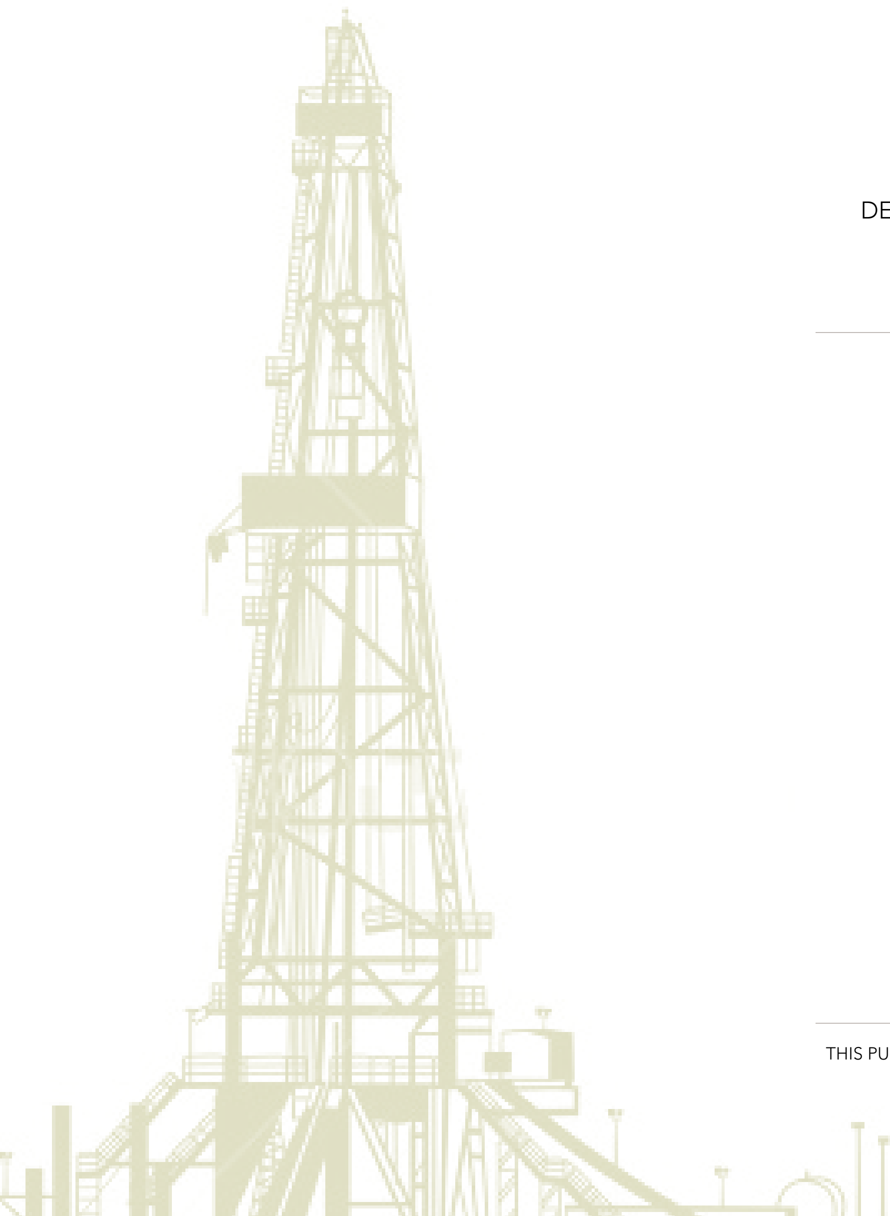
Graham Sustainability Institute
Erb Institute for Global Sustainable Enterprise
Risk Science Center
University of Michigan Energy Institute

GRAHAM SUSTAINABILITY INSTITUTE INTEGRATED ASSESSMENT REPORT SERIES
VOLUME II, REPORT 3

HYDRAULIC FRACTURING IN THE STATE OF MICHIGAN

Geology Technical Report

SEPTEMBER 3, 2013



Faculty Lead
BRIAN R. ELLIS
ASSISTANT PROFESSOR,
DEPARTMENT OF CIVIL AND ENVIRONMENTAL ENGINEERING,
MICHIGAN SOCIETY OF FELLOWS

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Direct questions to **grahaminstitute-ia@umich.edu**

EXECUTIVE SUMMARY

This report provides a survey of the Michigan Basin geology by discussing basin hydrogeological characteristics within the context of evaluating the impact of high-volume hydraulic fracturing. It also identifies existing knowledge and current practices related to extraction of oil and natural gas. In some instances, these practices are compared and contrasted to those of other states in order to provide perspective on the unique characteristics of the Michigan Basin. The goal of this report is to (1) guide the Phase 2 integrated assessment efforts as they pertain to evaluating questions specific to Michigan's unique geological characteristics and (2) serve as a resource for the non-technical reader who wishes to gain a fundamental understanding of Michigan Basin geology in the context of hydraulic fracturing practices and concerns within the state of Michigan. Although a thorough review of the existing data and literature was undertaken as part of this study, this report is not structured as a pure literature review. It is instead written with the purpose of providing an overview of the current knowledge as it relates to practices associated with hydraulic fracturing and to identify opportunities for additional data collection during the second phase of the integrated assessment.

Topics covered

In addition to providing a general background to the geology of the Michigan Basin and current unconventional resource plays within the state, this report focuses on several key issues related to evaluating hydraulic fracturing practices within the state of Michigan. These topics include:

- Regional fluid transport regimes within the basin
- Potential fluid migration pathways
- Proximity of hydraulically fractured wells to drinking water resources
- Factors controlling chemical composition of flowback waters
- Water use and disposal of flowback fluids

Summary of prioritized pathways for Phase 2 of integrated assessment

Several opportunities for additional data collection and improved technical understanding are identified in this report. These include:

- Establish baseline water quality for freshwater resources throughout the state
- Evaluate impact of hydraulic fracturing fluids on the release and transport of trace toxic metals and naturally occurring radionuclides from organic-rich shales
- Monitor extent of fracture propagation during hydraulic fracturing
- Evaluate potential for induced fluid migration associated with deep well brine disposal

In addition to addressing data gaps within the areas identified in the above list, it is suggested that better communication between all involved stakeholders be facilitated in order to best utilize resources and coordinate efforts related to these investigations. This includes improved knowledge sharing among stakeholders and the establishment of a common language for use in discussions related to hydraulic fracturing in the state of Michigan, the latter of which will be especially beneficial when communicating with the public on this topic.

1.0 INTRODUCTION

Growth in the extraction of oil and natural gas from unconventional reservoirs has drawn considerable attention to the practice of hydraulic fracturing. The oil and natural gas industry has long used the practice of hydraulically fracturing the rock surrounding a wellbore to enhance hydrocarbon extraction from conventional reservoirs. However, recent advances in directional drilling coupled with high-volume hydraulic fracturing stimulation techniques have made extraction of hydrocarbons from unconventional reservoirs, such as shale formations, economically viable. The rapid application of this technology has drawn the attention of many stakeholders, including local communities in areas where this extraction technique is being applied. The public discourse on the topic of hydraulic fracturing is highly polarizing and may often be driven by incomplete information, miscommunication or misunderstandings on both sides of the issue[1]. In seeking to address the topic of hydraulic fracturing within the limited context of the state of Michigan, the Graham Environmental Sustainability Institute has initiated an integrated assessment of hydraulic fracturing within Michigan. This report is designed to provide a broad discussion of the current knowledge pertaining to the unique geologic characteristics of the state of Michigan within this assessment framework, and to identify existing knowledge gaps that could be explored further during the second phase of the assessment.

1.1 Scope and usage of 'hydraulic fracturing' within the context of this report

As mentioned above, much of the attention focusing on the use of hydraulic fracturing to extract hydrocarbons from unconventional reservoirs is related the rapid expansion of shale gas drilling in states like Texas and Pennsylvania. Production of hydrocarbons from shale formations falls within the definition of 'unconventional' oil and natural gas extraction. This term is applied to hydrocarbon extraction from formations that do not possess naturally high permeabilities and often require extensive stimulation in order to be productive reservoirs[2]. Unconventional reservoirs, such as shale formations, may serve as both the source and the reservoir for the hydrocarbons stored within the rocks. Conventional reservoirs are formations with permeabilities sufficient to allow for economic flows of hydrocarbons to a production well without the need of extensive reservoir stimulation and often contain hydrocarbons that migrated from underlying source rocks. Common conventional reservoirs include sandstone and carbonate formations, however, low permeability reservoirs of these same lithologies (e.g. tight carbonates) can also be considered unconventional reservoirs.

Currently, there is minimal drilling activity within the state of Michigan that qualifies as high-volume hydraulic fracturing. There are fewer than 60 existing permits or active permit applications for high-volume completions in Michigan[3] (and some of these permits are for pilot wells that will not be high-volume completions). The Michigan Department of Environmental Quality (MDEQ) defines high-volume hydraulic fracturing as any hydraulic fracturing completion intended to use more than 100,000 gallons of hydraulic fracturing fluid[4]. If this report were to limit its discussion to only these instances it would be very narrow in its scope and discussion of Michigan's geology within the context of hydraulic fracturing practices in the state. As such, this report will focus on unconventional reservoirs in the Michigan Basin where hydraulic fracturing is utilized and not exclusively on high-volume hydraulic fracturing completions. The two primary unconventional reservoirs addressed in this report are the Antrim and the Utica-Collingwood shale formations. Hydraulic fracturing is used to enhance gas production from the Antrim, but high-volume completions are not necessary. This is in contrast to the Utica-Collingwood formation, which is currently being developed exclusively via high-volume hydraulic fracturing completions. Production from the A-1 Carbonate is also briefly discussed because of recent high-volume hydraulic fracturing well completions within this formation. A recent flurry of mineral rights acquisitions in 2010 associated with exploratory drilling in the Utica-Collingwood suggests anticipated potential growth in unconventional reservoir production via hydraulic fracturing within the state of Michigan, although only a handful of wells have been drilled in this reservoir since 2010[5]. Michigan is thus in a unique position to assess the future of high-volume hydraulic fracturing before the gas boom begins and learn from experiences in other states like Pennsylvania.

The following sections provide background coverage of the Michigan Basin geology and introduce several unconventional hydrocarbon reservoirs that are examined in this report.

1.2 Michigan Basin geology

The state of Michigan sits squarely in the center of the Michigan Basin. The Michigan Basin is a bowl-shaped, intracratonic sedimentary basin. The Michigan Basin sits atop crystalline basement rocks of Precambrian age, which lie at depths of approximately 16,000 feet below the surface in the thickest section of the basin near the center of Michigan's Lower Peninsula and 3,300 feet near the basin margins. The specific deformational history that led to the development of the Michigan Basin is still debated[6]. However, geodynamic modeling of basin development by Howell and van der Pluijm[7,8] suggests the Michigan Basin developed via several different stress-induced subsidence mechanisms (trough-shaped, regional tilting, narrow basin-centered, and broad basin-centered) occurring over discrete periods of time. These subsidence events coupled with deposition of sedimentary material created the basin as we see it today. Because much of the sedimentary strata formed under a shallow marine environment, the basin strata is dominated by carbonate and evaporite formation lithologies[8,9].

Past glaciation events have left the majority of the land surface in the state of Michigan covered by a thin layer of unconsolidated glacial deposits that overlay the sedimentary strata covering the entire Lower Peninsula and much of the southern half of the Upper Peninsula[10]. In northern and western sections of the Upper Peninsula igneous rocks outcrop at the surface, providing the copper and iron ore that are mined in areas such as the Keweenaw Peninsula and Marquette.

A formation outcrop is described as a location at which it is visible at the surface. But in the case of the Michigan Basin where the majority of the land surface is covered in a veneer of glacial sediments, the sedimentary formations within the basin are seldom visible at the surface. The location at which a formation would be visible at the surface if not for being covered by unconsolidated sediment is referred to as a formation subcrop. Figure 1(a) provides an overview of the basin geology, showing the characteristic 'bull-seye' outcrop/subcrop pattern found in the basin. When viewed in cross-section, as shown in Figure 1(b), it is observed that the sedimentary strata dip toward the center of the state from all directions. This is why the basin is described as being bowl-shaped. Figures such as 1(b) are exaggerated in the vertical direction to clearly show the bowl shape of the basin as the actual formation dip is very gradual, generally being on the order of 1° or less.

Due to extensive hydrocarbon exploration and production within the state, Michigan's geology is well characterized. It is believed that the basin has been tectonically stable since the Jurassic[9]. At its thickest point near the center of the Lower Peninsula, the sedimentary strata is approximately 16,000 feet thick and is underlain by Precambrian igneous and metamorphic rocks. Common terminology refers to the underlying crystalline rocks as the basement rocks because they represent the end of the sequence of sedimentary strata.

Figure 1: (a) Michigan Basin outcrop geology; (b) Cross-section (from the northwest to the southeast) of the Michigan Lower Peninsula demonstrating the bowl-shaped basin stratigraphy (vertical exaggeration). From MDEQ.

Figure 1a
1987 Bedrock Geology of Michigan

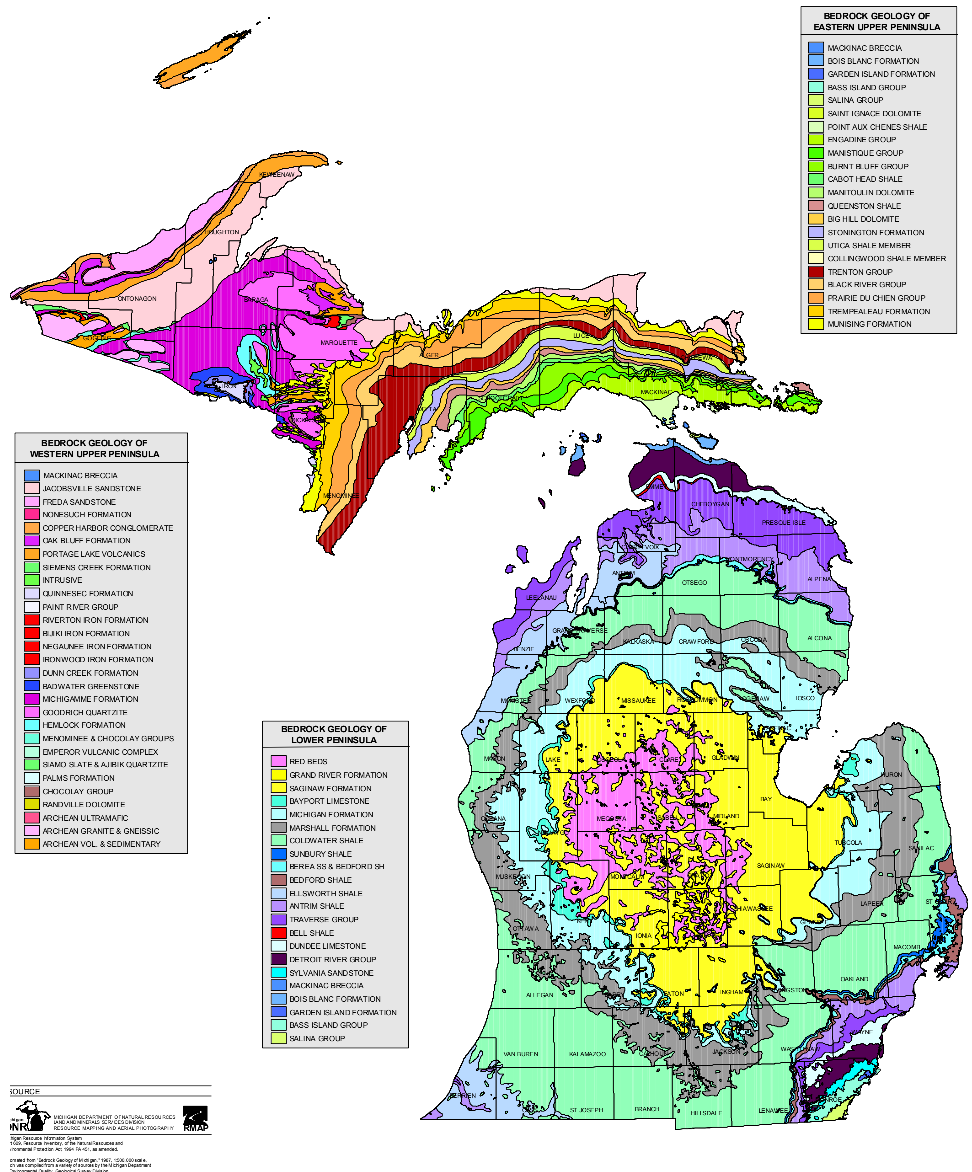
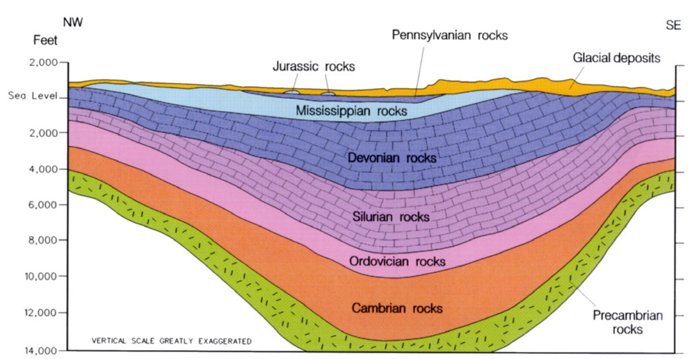


Figure 1b



1.2.1 Fundamental hydrogeology concepts and terminology

Sedimentary rocks can be either aquifers or aquitards. A simple way to think about aquifers versus aquitards is that an aquifer is a permeable geologic formation from which water can be extracted in good quantity, whereas an aquitard is a low permeability geologic formation with insufficient permeability to allow for significant water production. Aquicludes have essentially no flow of water whatsoever and can be thought of as the extreme end of impermeable aquitards. Examples of typical aquifer lithologies are sandstone and limestone formations, while shales are common aquitards. It is important to note that not all aquifers are freshwater aquifers. In the Michigan Basin the vast majority of water contained within the sedimentary strata is saline water not suitable for drinking. Potable drinking water is found at shallower depths in the glacial aquifers and near the recharge zones of some sedimentary formations.

Porosity is the percent void space within a unit volume of rock. Two good examples of porosity in common objects are (1) the voids within a sponge and (2) the void space within a jar filled with marbles. In both cases, there is a unit of volume delineated by the outer edges of the object (sponge dimensions, total jar volume). Within this unit volume is space occupied by both solid material (sponge, marbles) and air. The relative volume of air to the total volume, represented mathematically as ($air[m^3]/Volume_{TOT}[m^3]$), is the porosity of the system (Φ). It is therefore unitless and is given as a percentage. Porosity alone will not dictate whether a given formation will be an aquifer or an aquitard, as the key determinant here is the formation permeability. Permeability is a measure of the ease with which a substance moves through a porous medium and reflects the degree of connectedness of the pores within geologic media.

1.2.2 Michigan Basin stratigraphy

The lowest sedimentary unit in the Michigan Basin is the Mt. Simon sandstone, which is a regional saline aquifer. Due to its high porosity and permeability it has been used as a storage formation for waste injection and is considered to be a target storage formation for the underground sequestration of CO_2[11]. Overlying the Mt. Simon is the Eau Claire confining unit, which is part of the Munising Group that consists of a series of interbedded sandstones, dolomite, and mudstones[12,13]. Above the Munising Group is the early Ordovician Prairie Du Chien Group consisting primarily of dolomite and sandstone with some minor shale lenses[12]. The St. Peter sandstone is a saline aquifer that sits on top of the Prairie Du Chien Group strata[14]. The middle Ordovician age Trenton and Black River carbonate formations overlie the Glenwood shale immediately above the St. Peter sandstone.

The Trenton is overlain by the Utica shale throughout the state and by the organic-rich Collingwood limestone in portions of the northern Lower Peninsula. The Utica-Collingwood formation is recognized as major source rocks for hydrocarbons within the Michigan Basin[13]. A thick sequence of Silurian-age strata lies unconformably above the Utica beginning with the Manitoulin dolomite and the Cabot Head shale. Above the Cabot Head shale lie the Burnt Bluff Group and the Manistique Group carbonates. The Niagaran Group is found above the Manistique Group and is composed predominantly of micritic limestone and dolostone. This group is a major hydrocarbon reservoir in the state of Michigan and is generally sub-divided by the oil and gas industry into three units (Brown (top), Gray and White (bottom)) based on color, texture, and faunal properties[12]. The Salina Group is found above the Niagaran and is composed of a thick sequence of evaporite (e.g. halite, anhydrite and gypsum) and mixed carbonates. The evaporites are basin-centered, thinning toward the outer margins of the Salina Group where they are no longer present. Above the Salina Group is the Bass Islands Group, a dolomitic saline aquifer, which is overlain by the regionally confining units of the Bois Blanc (cherty carbonate) and Detroit River Group. The Detroit River Group was formed during the middle Devonian and is composed of a mixed series of carbonates, evaporites, and sandstones. The Dundee and Rogers City limestone formations sit atop of the Detroit River Group. The Dundee is a hydrocarbon-bearing reservoir in the central portion of the Michigan Basin and is often targeted for wastewater injection along its periphery. The Traverse Group is another regional saline aquifer dominated by a vuggy limestone lithology. The Bell shale sits at the base of the Traverse group and serves as a confining unit separating the Traverse and Dundee Groups[15].

The organic-rich Antrim shale is above the Traverse Group and serves as another primary source rock for oil and natural gas within the Michigan Basin[13]. A series of confining shale units lies atop of the Antrim. Moving up the strata we find the Ellsworth, which represents of the end of Devonian strata, followed by the Mississippian-aged Sunbury, and Coldwater shales. In eastern portions of the basin the Berea sandstone, a regional saline aquifer, lies between the Antrim and Coldwater shales. Another sandstone aquifer, the Marshall sandstone lies above the Coldwater shale. The Michigan formation, which is considered a confining unit[14], consists of a mix of dolomite, shale, and evaporites[12]. The final units in the Michigan Basin stratigraphy are the Saginaw formation, a regional aquifer, and the Ionia formation, a regional confining unit[14].

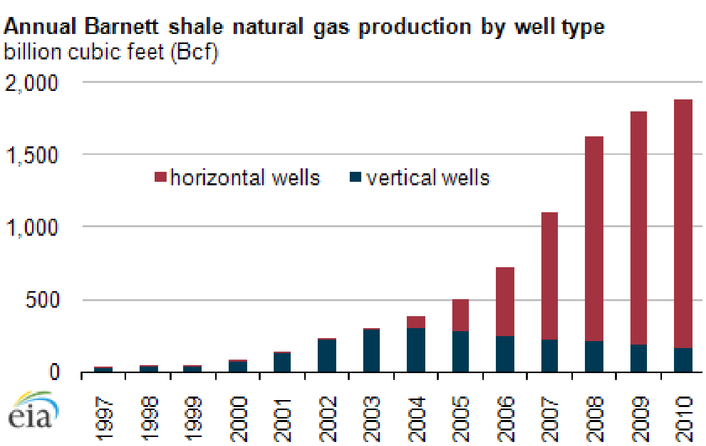
This extensive list presents a comprehensive representation of the Michigan Basin stratigraphy, but for the sake of discussing basin hydrology many of these individual units are lumped together into what can be considered general aquifer and aquitard units, as will be discussed later in this report[14].

1.3 Oil and gas drilling in Michigan

Hydraulic fracturing of oil and natural gas wells is common practice in Michigan. The MDEQ reports that more than 75% of recent wells drilled in Michigan have been hydraulically fractured and estimates that a total of 12,000 wells have been hydraulically fractured to date within the state of Michigan[16]. Given that the focus of the broader integrated assessment effort is on high-volume hydraulic fracturing, for the purposes of this report it is important to draw a distinction between the process of hydraulic fracturing, in general, and high-volume hydraulic fracturing, in particular. Most of the wells in Michigan that have been hydraulically fractured do not qualify as high-volume completions (i.e. they have used <100,000 gallons of hydraulic fracturing fluid). The technique of hydraulic fracturing has been used since the 1940's by the oil and gas industry to enhance the production of wells[17]. High-volume slickwater hydraulic fracturing is a relatively new practice that often combines directional drilling and hydraulic fracturing at larger scales, thus requiring larger volumes of water for well completions. The term 'slickwater' refers to the hydraulic fracturing fluid mixture, which includes friction reducers in addition to other chemical additives designed to optimize the hydraulic stimulation process. Directional drilling refers to the process where the direction of the drill bit is gradually deviated from the vertical, allowing the well to follow a formation in the horizontal direction. In the case of shale-gas wells, such drilling may be coupled with hydraulic fracturing to provide increased access to the stored natural gas within the impermeable rock matrix. To be clear, not all horizontal wells are high-volume completions, and not all high-volume completions include horizontal drilling.

It is no surprise that organic-rich shales hold economic quantities of oil and natural gas, as these same formations serve as the source rocks for the hydrocarbons found in more conventional reservoirs (e.g. sandstones). However, the low permeability of these formations prevented economic production via traditional drilling and well completion methods[2]. Within the past decade the interest in and exploration of unconventional reservoirs has increased dramatically due to successful applications of high-volume hydraulic fracturing in shale reservoirs. The increased application of directional drilling coupled with hydraulic fracturing and its impact on productivity of unconventional gas production is evident when examining Figure 2, which shows the production of natural gas from the Barnett shale in Texas from 1997–2010 as a function of the type of well drilled (vertical vs. horizontal). This horizontal drilling and hydraulic fracturing activity also led to increased water consumption. Between 2009 and June 2011 the median amount of water used to hydraulically stimulate horizontal wells in the Barnett shale was 2.8 million gallons per well[18]. The growth in U.S. domestic shale-gas reserves has led the U.S. Energy Information Administration to predict that natural gas extracted from shale formations will total 49% of all domestic natural gas production by 2035[19].

Figure 2: Annual Barnett shale natural gas production by well type. Figure from U.S. Energy Information Administration[20].



Because extraction of natural gas from shales has experienced such rapid growth, it seems appropriate to provide some background on shale lithology and hydrocarbon generation. Shale is a fine-grained sedimentary rock rich in clay minerals and often contains elevated concentrations of organic matter. Plant and animal organic matter can be deposited within sedimentary rocks, and when this occurs rapidly in anoxic marine environments, the organic material may be preserved within the rock. Overtime, further sedimentation and burial may expose these sediments to higher temperatures and pressures found deeper within the Earth's crust. Thermal breakdown of this organic material can lead to the formation of kerogen, which is the primary ingredient in the generation of hydrocarbons. Under the right temperature and pressure conditions, kerogen may be further transformed into natural gas, oil or CO_2. Organic-rich shales serve as the source rocks for traditional oil and gas reservoirs when the oil or gas is able to migrate beyond the shale and accumulate under an overlying stratigraphic or structural trap. However, due to the inherently impermeable nature of shale formations these products are often trapped within the shale and until recently, were not considered to be economically recoverable resources[21]. It is thus only due to the recent advances in directional drilling and slickwater chemical formulations that unconventional extraction of natural gas from organic-rich shale formations has become economically viable via high-volume hydraulic fracturing completions.

In deep shale gas reservoirs, natural gas exists primarily as free gas within the shale porosity (both interstitial and fracture porosity). Additional gas may also be adsorbed to the surfaces of clay minerals and organic matter. The fracture networks created during the hydraulic fracturing process allow the trapped gas to flow to the well. The fractures also generate increased surface area pathways within the formation allowing for enhanced gas desorption.

1.4 Unconventional hydrocarbon reservoirs in the Michigan Basin

The following section presents background information and characterization of several unconventional reservoirs within the Michigan Basin. The order of presentation will begin with a discussion of the most developed natural gas play, the Antrim shale. This will be followed by discussion of the Utica-Collingwood shale, which is a developing target reservoir where high-volume hydraulic fracturing has been utilized in recent drilling efforts. Lastly, a brief discussion of the A-1 Carbonate formation will be presented given that there is also interest in high-volume hydraulic fracturing within this formation[3]. Although not discussed in detail in this report, the Trenton-Black River carbonate formation has also been a target for high-volume hydraulic fracturing completions. The Trenton-Black River would be considered a conventional reservoir with the mature Albion-Scipio field having been actively produced for nearly 50 years. Although uncommon, high-volume completions in the newer Napoleon field may be used to overcome inconsistent and highly variable reservoir quality[22]. Wells may be in the vicinity of good reservoir rock that could be accessed more easily through well stimulation as opposed to drilling a second well. These completions tend to be just above the high-volume threshold of 100,000 gallons of hydraulic fracturing fluid. In compiling this report it was decided to limit discussion to unconventional reservoirs, that is, those reservoirs that can be considered 'continuous plays' and are especially amenable to high-volume hydraulic fracturing completions.

Data on formation total organic content (TOC), which serves as a proxy for potential hydrocarbon content, and lithology characteristics were collected from the Michigan Geologic Repository for Research and Education in Kalamazoo, Michigan.

1.4.1 Antrim shale

The Antrim shale was one of the first economic shale-gas plays in the U.S. and has been actively developed since the 1980's. It is a naturally jointed formation with significant gas production occurring at relatively shallow depths (~1,000–2,000 feet below the surface)[23,24]. These two aspects have allowed for economic production of the natural gas in place through use of traditional extraction methods (i.e. vertical wells). The Antrim is somewhat unique among shale-gas reservoirs in that it produces significant volumes of water[25]. This is due to its highly naturally fractured nature[26] and proximity to subcrop recharge, which consequently has also led to biogenic methane production in much of the active play near the northern formation subcrop region[27,28]. The majority of Antrim natural gas production wells are located in what is referred to as the Northern Producing Trend centered near Otsego County and

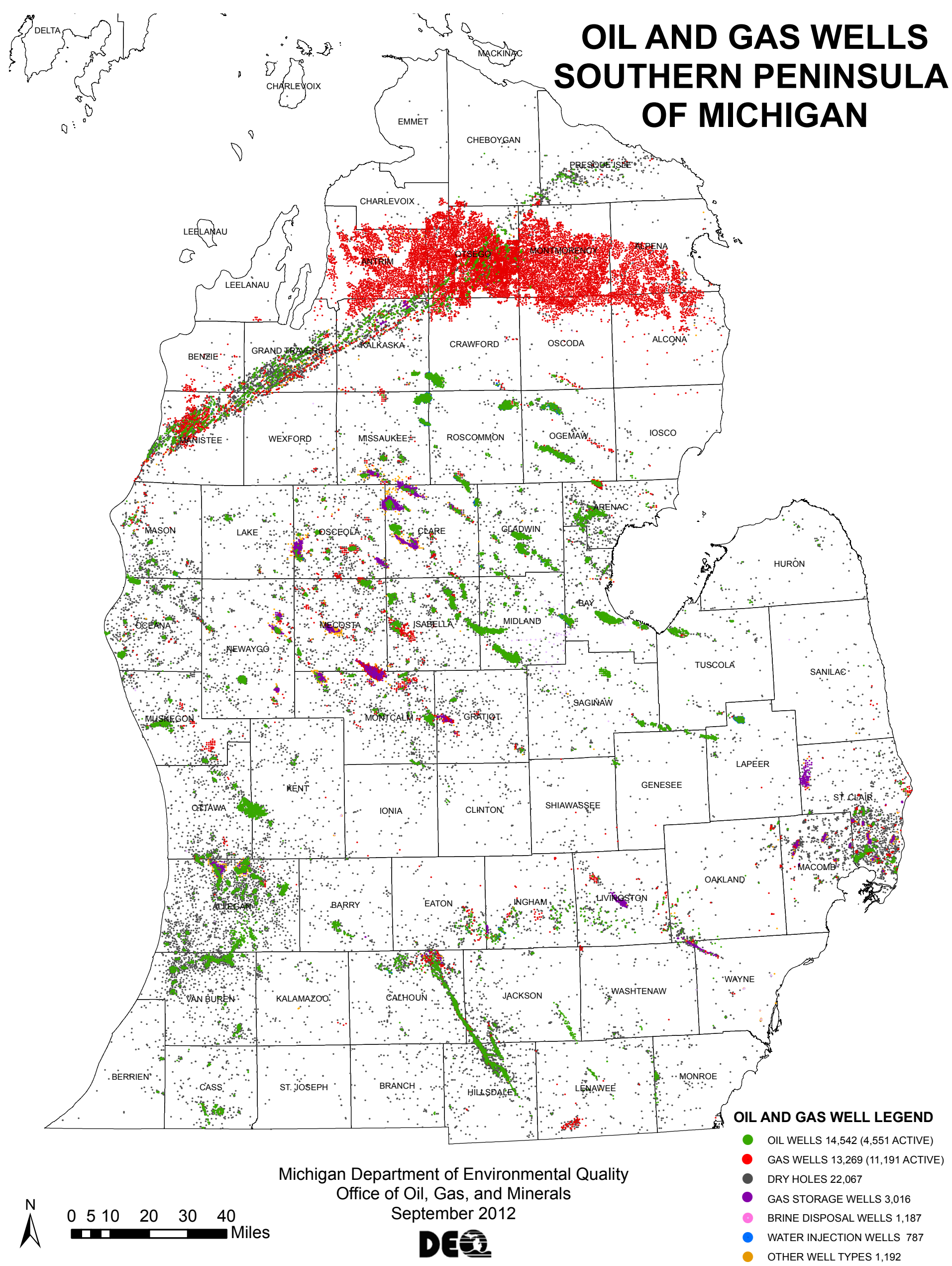


Figure 3: Oil and gas wells in Michigan's Lower Peninsula. The Northern Producing Trend of the Antrim is evident by the high density of natural gas wells (red dots) in the northern Lower Peninsula. From MDEQ[23].

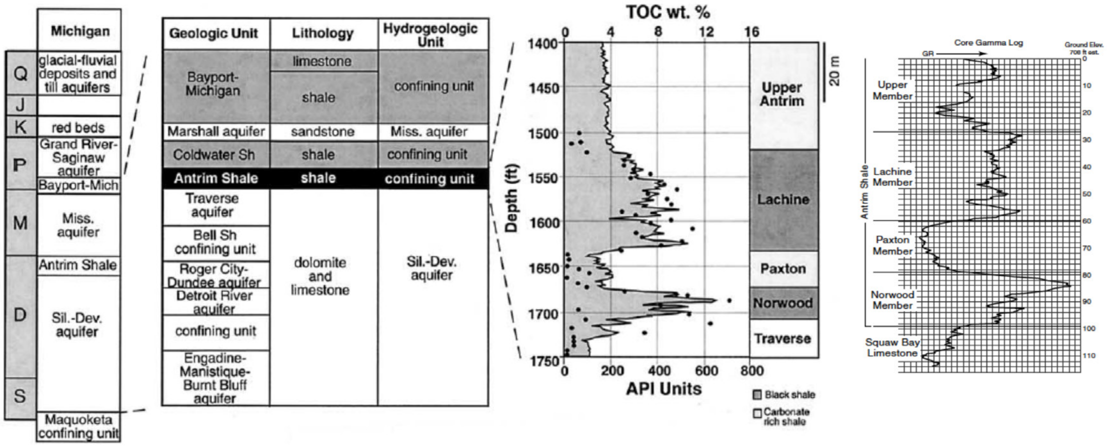


Figure 4: (a) Stratigraphic column focusing on the Antrim shale; (b) Antrim units and total organic carbon (TOC); (c) the corresponding gamma ray log for the Antrim shale. Figures modified from McIntosh et al.[32] and Curtis[33].

extending to its neighboring counties in the east and west. This region of Antrim production wells is evident in Figure 3 by the high density of natural gas wells in the northern half of the Lower Peninsula.

The Antrim comprises four distinct zones, as shown in Figure 4(b). The main producing zones are in the lower Antrim, specifically, the Lachine and Norwood zones, which have elevated concentrations of organic matter. The occurrence of natural radioactive elements such as U correlates well with the organic content of black shales[29]. This makes gamma ray logs, which measure the gamma radiation from the bulk rock along a well segment, quite a useful tool in identifying potentially gas-rich zones with high organic content. Measured TOC content in the Antrim ranges from <1–25%wt, with an average of 8%[24]. The Antrim shale is a naturally highly fractured formation[26,30]. The average porosity in the Antrim is 9%, and it is assumed that natural gas fills roughly half of this porosity[31]. Given that the Antrim shale contains a substantial network of natural fractures, economic quantities of natural gas can be extracted through use of vertical wells and low-volume hydraulic fracturing stimulation that opens horizontal fractures to better connect the natural fractures with the production well.

While organic thermal maturity in the Antrim supports the possibility for hydrocarbon development near the deeper portions of the Michigan Basin[34,35], a large portion of the produced gas along the margins of the Antrim play, specifically that of the Northern Producing Trend, is of biogenic origin[27,28,36]. The reason for this biogenic methane production is that the Antrim experienced significant Pleistocene freshwater intrusion that facilitated the growth of methanogenic microbes *in situ*[32,37,38].

Although directional drilling has been used to extract natural gas from the Antrim, it is not the most common practice as vertical wells often provide sufficient contact with production zones. It is standard practice to fracture wells drilled in the Antrim prior to completion. Nitrogen foam fracturing was often used in the past, but slickwater hydraulic fracturing has recently become more common in this play (Wilson and Schwank, this series). Recent efforts have investigated use of directional drilling techniques to access very shallow Antrim production zones and natural gas under areas where surface access is limited[39]. These test wells were not high-volume hydraulic fracturing well completions, yet they do demonstrate opportunities for future growth in the use of directional drilling techniques to extract additional natural gas from the Antrim shale. There is an overall decreasing trend in the net production of natural gas from the Antrim shale and the number of new wells being drilled in this play.

1.4.2 Utica-Collingwood formation

The Utica shale is present throughout the Michigan Basin and is composed primarily of compacted clay minerals and quartz, in addition to minor carbonate minerals. Common TOC values for the Utica are found to be in the range of 0.5–1.3%wt. Water saturation in the lower Utica is approximately 44% and porosity ranges between 3–4%. The Collingwood formation is an organic-rich carbonate with moderate clay mineral content (~20%vol) and would most accurately be described as a limestone, not a shale. Average TOC values in the Collingwood range from 1–6%wt. Total porosity estimates in the Collingwood are between 2–5% with almost no water saturation. The Collingwood is located at the top of the Trenton formation, near the bottom of the Utica shale and is present over only a small section of the northern Lower Peninsula, as is indicated in Figure 5.

The Collingwood outcrops in Collingwood, Ontario, Canada, near the shores of Lake Huron. The Collingwood facies is quite thin. At its thickest, the Collingwood is only found to be around 35 feet in total thickness and narrows toward the basin center prior to disappearing. It is thus often grouped with the overlying organic-rich zone of the Utica shale because production wells will likely capture both facies within the hydraulically stimulated zones. Together,

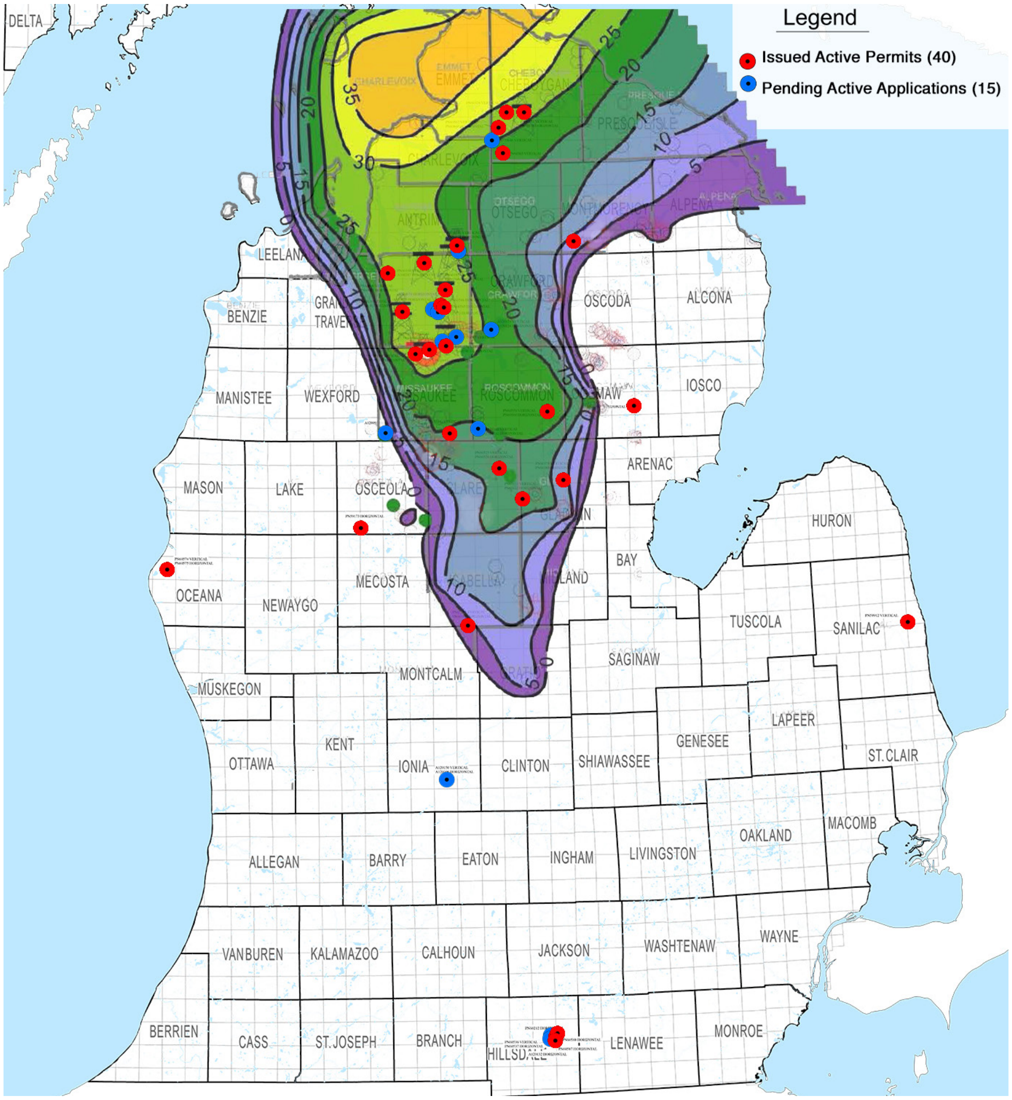


Figure 5: Map showing the issued and pending permits for high-volume hydraulically fractured wells[3]. The extent of the Collingwood is also shown with formation thickness (in feet) given by the isopach map.

these two formations are referred to as the Utica-Collingwood formation. The Utica-Collingwood is a newly developing reservoir, having gained much attention from industry after the successful drilling of one deep horizontal well by Encana in late 2009[5]. Figure 5 also shows the current and pending permits for high-volume hydraulic fracturing in Michigan. A key take-away point related to Figure 5 is that the majority of applications for high-volume well completions in Michigan are located in the Utica-Collingwood.

1.4.3 A-1 Carbonate

The A-1 Carbonate is part of a sequence of evaporite and carbonate formations that form the Salina Group. Historically, the A-1 Carbonate in Michigan has been a primary hydrocarbon reservoir. It is bounded from above and below by evaporite formations and has three distinct areas of hydrocarbon production within the basin. In the northern and southern portions of the Lower Peninsula, several production wells target the A-1 overlying the Niagaran Pinnacle Reef. In the southwestern region of the Lower Peninsula there is some hydrocarbon production from the A-1 where the reservoir displays solution-enhanced porosity and fracturing due to salt dissolution. Much of the potential production from the A-1 via high volume hydraulic fracturing is within the central portion of the Michigan Basin, including the south central and western central areas of the Lower Peninsula. Higher porosity and permeability within the A-1 in this region occurs as intercrystaline porosity due to dolomitization and provides a more continuous resource play conducive to development via high volume hydraulic stimulation techniques[40]. Porosity in this region is on the order of 6–7% and TOC values tend to be <1%wt.

2.0 STATUS, TRENDS & ASSOCIATED CHALLENGES

The main body of this report is split across five primary topics of interest:

1. Michigan Basin hydrogeology

2. Potential fluid migration pathways

3. Unconventional reservoir proximity to drinking water resources

4. Flowback water chemistry

5. Water withdrawal and disposal

In the following section a review of each topic is presented, including identification of challenges and opportunities to address data gaps associated with each topical area.

2.1 Michigan Basin hydrogeology

2.1.1 Hydrogeologic units

The Michigan Basin is composed of a series of sedimentary formations stacked upon one another, each having different characteristics in terms of porosity, permeability, mineralogy, and overall levels of heterogeneity across all of these properties. Even within a single formation these characteristics may change as one moves from the basin center outward toward the margins. In some cases (e.g. Collingwood) a given formation may not be continuous throughout the basin. The majority of sedimentary formations within the Michigan Basin are either water saturated or contain a mixture of water, oil, natural gas, and CO_2. Formations with very low porosity and permeability may not always be fully fluid saturated. A formation is described as being fully saturated when a fluid occupies all of the available porosity. If the permeability is sufficient to allow flow of water within the formation and/or allow water to be extracted in significant quantities, the formation is described as an aquifer. Figure 6 illustrates an approximate grouping of aquifer and aquitard units in the Michigan Basin. Michigan Basin formation waters tend to be highly saline. Formation water salinity is due to a combination of formation water origin being derived from evaporated Paleozoic seawater and due to dissolution of evaporite deposits[41–43]. Formation water salinity increases rapidly with depth, reaching total dissolved solids concentrations of >350 g/L at depths as shallow as 2,600 feet[37].

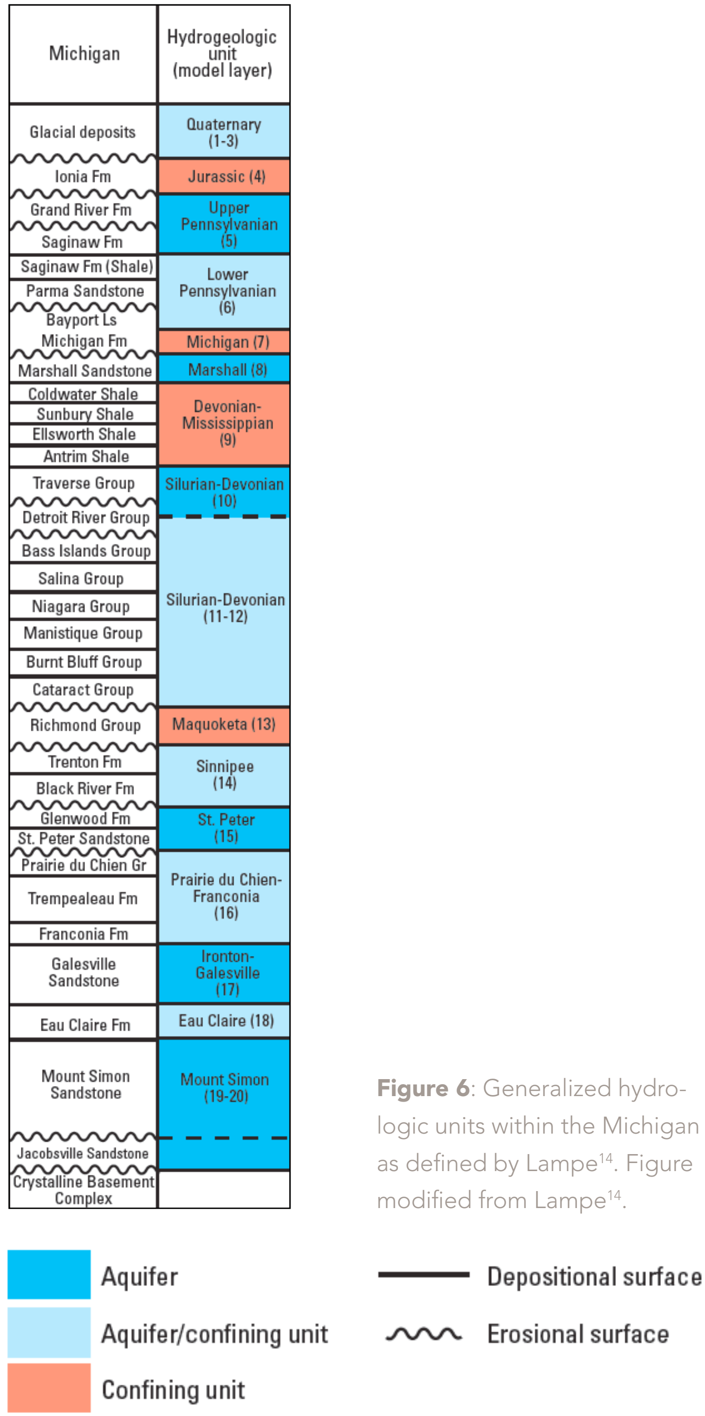


Figure 6: Generalized hydrologic units within the Michigan as defined by Lampe[14]. Figure modified from Lampe[14].

2.1.2 Regional subsurface flow

Fundamentally, groundwater flow is driven by hydraulic gradients with water flowing from areas of high pressure to areas of low pressure. In the Michigan Basin modern groundwater flow occurs from areas of higher elevation to areas of lower elevation, generally following surface topography with flow from topographic highs in the north, west, and south toward the topographically lower Saginaw Bay area[15]. Meteoric water recharges the glacial aquifers at the surface and maintains the water level in these open aquifers. At topographic highs, meteoric water also recharges sedimentary formations where they subcrop below the glacial till[15]. In shallower aquifers such as the Marshall sandstone, flow from recharge zones in the northern and southern subcrop regions discharges into Lake Michigan and Lake Huron in the western and eastern subcrop zones[44].

A study by Vugrinovich[45] found a correlation between lower subsurface temperatures and zones of aquifer recharge in Devonian and Ordovician aquifers within the Michigan Basin. Positive deviations away from the geothermal gradient for the Michigan Basin of 19°C/km, which assumes that heat transfer occurs only due to conductance, were found near aquifer discharge zones. This suggests that regional groundwater flow and subsurface heat transfer are correlated. Deviations away from the expected geothermal gradient, as evidenced by Vugrinovich[45], are associated with subsurface convection and correlate with regional groundwater flow patterns—for example, cooler waters correspond to aquifer recharge zones. Evidence of subsurface temperature gradients and measured hydraulic head suggest that groundwater flow in many of the deeper aquifers in the Michigan Basin occurs with recharge at formation subcrops in the southern and northern portions of the basin with discharge near the Saginaw Bay region[15,45].

The following paragraph draws heavily on data presented by Vugrinovich[15], who completed a very thorough study of regional flow characteristics of deep brines in the Michigan Basin. Although many of the aquifers in the Michigan Basin present hydraulic head distributions that mimic surface topography, suggesting gravity-driven flow conditions, some aquifers present deviations from expected nominal pressure gradients corresponding with depth. When aquifers are bounded by aquitards (e.g. shales), *in situ* pressure conditions may be higher than those expected for an equivalent column of water at a given depth (nominal expected pressure), which means the aquifers have not reached equilibrium with the current land surface topography. An example of one such aquifer is the Berea sandstone, which is bounded from above by the Sunbury shale and below by the Bedford and Antrim shales. Evidence that the Berea remains overpressured supports the existence of good confining characteristics (i.e. low permeability) of the shales that bound it. The Antrim is also found to be overpressured over much of the basin and is believed to leak into the underlying Traverse limestone[15]. The Dundee formation is substantially underpressured near the center of the Michigan Basin, with recharge occurring throughout the basin from both the overlying Traverse limestone and the underlying Detroit River Group aquifers. The confining units that separate these aquifers from the Dundee are considered to be leaky aquitards. The hydraulic low in the central portion of the Michigan Basin is believed to be associated with artificial fluid discharge related to hydrocarbon production from the Dundee within this region. The A-1 Carbonate is overpressured in the central portion of the Lower Peninsula as it is bounded from above and below by impermeable evaporite formations. The fact that the A-1 remains overpressured and has not re-equilibrated with the current surface topography demonstrates the good confining characteristics of the overlying strata. Where the A-1 is unconfined near the edges of the basin, flow is thought to be gravity-driven, with discharge occurring in the southern end of the Lower Peninsula and under Lakes Huron, Michigan, and Erie. Finally, flow within the Trenton-Black River occurs with recharge at the subcrop and flow is toward the center of the basin. Data suggest that the Trenton-Black River aquifer is confined by the bounding aquitards. This supports the basin-wide impermeable nature of the Utica-Collingwood that overlies the Trenton limestone.

Measured elevated concentrations of Br and He in shallow aquifers provide evidence of vertical leakage of deeper brines into shallower formation waters (Marshall sandstone, glacial drift)[44]. Higher concentrations of Br are representative of evaporated seawater[46] and help differentiate the origin of brine salinity from that of dissolution of evaporites that would result in very little Br component[47]. Near the recharge zones of the Marshall, the water in the sandstone is potable and serves as the primary source of municipal drinking water for much of Jackson County[48]. By the time the water discharges from the Marshall sandstone into the Saginaw Bay it is nearly as saline as the underlying Antrim and Traverse brines. This observation coupled with the evidence of elevated concentrations of the two conservative tracers (Br, He) support upward migration of deeper basinal brines from the Traverse limestone into the overlying Marshall sandstone[44].

2.2 Potential fluid migration pathways

Concern of water quality impacts and specifically, groundwater contamination, is often cited as top issue regarding the environmental implications of hydraulic fracturing[49]. This is understandable given that clean drinking water is a resource that we cannot live without. Migration of methane, the dominant component of natural gas, into groundwater reservoirs has received significant attention in the context of unconventional natural gas extraction. Natural gas migration beyond source rock formations is commonplace and is what leads to the development of conventional natural gas plays. The reason for this is that methane gas is much less dense than water and therefore will rise due to buoyant forces if a pathway allowing vertical migration exists. Reports of natural gas migration into drinking water aquifers[50] and investigations of contamination of drinking water by hydraulic fracturing chemicals[51] have fueled public concern of drinking water contamination by hydraulic fracturing-related activity.

A study by Osborne et al.[50] cited evidence for natural gas migration into shallow drinking water aquifers associated with natural gas drilling in Pennsylvania. These authors used carbon isotopes to differentiate between thermogenic (i.e. 'deep') methane and biogenic (i.e. 'shallow') methane in order to determine the origin of methane found in the drinking water wells. The assumption was that methane of thermogenic origin could only be found in well water if it were to have escaped from deeper sources such as (but not exclusively) from the Marcellus shale, whereas methane derived from methanogenic microbial activity would be found in shallow reservoirs where meteoric water recharge takes place. A conclusion from this study was that water wells located nearby natural gas production wells had a higher contribution of thermogenic methane than wells that were further away from natural gas drilling sites. The association of shallow water thermogenic methane contamination with hydraulically fractured natural gas wells led the authors to suggest a link between the practice of hydraulic fracturing and methane seepage to the surface. To be clear, the study by Osborne et al.[50] does not definitively ascribe methane leakage to hydraulic fracturing, but inferences are made that suggests such a link may exist. It was noted that another possible, if not more likely, leakage pathway could be flow up the wellbore due to incomplete well cementation. Such leakage would be non-unique to hydraulically fractured wells and therefore does not necessarily provide any evidence directly related to hydraulic fracturing-derived leakage. A different study by Molofsky et al.[52] suggested that methane leakage occurs naturally and is not correlated with natural gas drilling activity, but instead, topography. Others have also pointed out that natural seepage of methane is known to occur and have argued that without baseline measurements of methane concentrations prior to drilling activity one is unable to definitively attribute methane in drinking water to drilling activities[53–55]. As these competing studies demonstrate, assessing leakage can be quite complicated and requires having well established baseline water quality data[49].

The key issue regarding leakage is the existence of leakage pathways coupled with a driving force promoting vertical migration of fluids beyond the stimulated reservoir. This report does not attempt to assess the likelihood of groundwater contamination from hydraulic fracturing in Michigan. However, theoretical leakage pathways and the parameters controlling movement of fluids beyond the fractured reservoir are discussed in the following sections.

2.2.1 Fracture propagation

One concern surrounding the practice of hydraulic fracturing is that the induced fracture network will extend beyond the target formation. If this were to occur then flow pathways would exist between the target reservoir and overlying formations, possibly allowing for migration of fracturing fluids beyond the production reservoir. The topic of hydraulically-induced fractures has been studied extensively, as understanding how the fracture network develops is key to both evaluating the enhanced productivity of a well and ensuring the safety of overlying sources of potable water[56,57]. A study by Fisher and Warpinski[58] provides information on the relative height of induced fractures as a function of depth for several unconventional resource plays across the U.S. collected over a 9-year period ending in 2010. Data gathered from hydraulically stimulated wells in other states does not show evidence of hydraulically-induced fractures extending into overlying fresh water aquifers[58]. This data does not support the scenario for propagation of fractures all the way to the surface; however, no data was collected for drilling activity in the Michigan Basin. Collection of similar data for hydraulic fracturing operations in Michigan would be beneficial in helping evaluate the extent and direction of fracture propagation within the unconventional plays in the Michigan Basin.

2.2.2 Existing faults, natural fracture networks, diffuse leakage

Natural leakage of natural gas and oil from shale source rocks is common and is the mechanism by which economic deposits within permeable reservoirs develop. In the case of conventional natural gas exploration, gas plays are often identified by the existence of natural stratigraphic or structural traps above permeable reservoirs that overlie organic-rich source rocks. The fundamental force driving the upward migration of oil and natural gas is that these fluids are less dense than formation brines and rise due to natural buoyant forces. Vertical migration of these fluids takes place over geologic timeframes and is often retarded or completely blocked by overlying impermeable formations. In areas where impermeable caprocks are not present above source rocks, for example at locations where the Antrim subcrops beneath glacial drift in Michigan, evidence of natural gas migration into potable aquifers has been found[59].

As previously discussed in section **2.1.2**, widely distributed cross-formational flow from deeper formations to shallower formations has been documented in the Michigan Basin based on high He fluxes and elevated Br- concentrations in the Marshall sandstone[44], confirming previous explanations for the occurrence of higher salinity brines at shallow depths within the basin[60]. Evidence for natural leakage of deeper brines into shallower formations is not unique to the Michigan Basin. Warner et al.[61] recently found evidence for natural migration of Marcellus shale brines into shallower aquifers. One important issue to point out here is that the timeframe for this natural vertical brine leakage is not well known, and it is thus difficult to relate such leakage, which may have taken place over geologic timescales, to the short timescales of recent subsurface energy extraction practices. Additionally, low water saturations in many shale gas formations may create strong capillary tension trapping mechanisms that prevent upward migration of injected fluids and formation brines[62].

Many of the existing oil and gas fields within the Michigan Basin are associated with structural features such as low displacement faults[30]. The two largest of these structural features are the Howell Anticline and the associated Monroe-Lucas Anticline structures in southeast Michigan. Low displacement faulting is observed across the Michigan Basin in a general northwest-southeast trending direction. These features can be closely linked to the oil and gas plays shown in Figure 3 by noticing the spatial trends in oil wells across the state. Many of these structural features can be interpreted as small anticline folds due to minimal vertical displacement of the geologic strata. Although the deformation events that generated these anticline structures within the basin were not severe enough to cause significant sediment displacement, they are believed to have allowed vertical migration of hydrothermal fluids that lead to dolomitization across much of the Michigan Basin[30]. The natural jointing within the Antrim shale is also dominantly northwest-southeast and in some cases may be associated with stresses from these features[26]. It is not clear, however, that the jointing in the Antrim can be attributed solely to structural trends within the basin[63].

2.2.3 Leakage along well bores

Existing wells may serve as leakage conduits if they are improperly sealed or if their seals have been degraded over time[64,65]. When wells are drilled, completed, or abandoned, drilling companies must abide by regulations that specifically state what efforts that must be undertaken to ensure that no contamination of potable aquifers occurs due to fluid leakage up the wellbore or along the well annulus (exterior of the well casing)[66]. These include guidelines for well casing, cementation, and plugging. However, these types of stringent guidelines aimed at ensuring the safety of overlying drinking water resources were less common or non-existent prior to the 1950's. In the past, abandoned wells may not have been properly plugged due to previously lax regulatory enforcement, and these wells may be poorly documented[67]. This means that there is a level of uncertainty regarding the integrity of wells drilled and/or abandoned prior to this time period.

Undocumented abandoned wells are often described as being orphan wells. To address the issue of orphan wells in Michigan, the Orphan Well Program (Act 308) was established in 1994. This program provides funding for the identification and remediation of improperly abandoned wells located in Michigan. This proactive approach to addressing leakage concerns related to abandoned wells is a step in the right direction toward reducing the likelihood of leakage up existing wellbores within the state of Michigan. To address the issue of existing wells in close proximity to newly permitted wells, the MDEQ requires the operator of a proposed well to evaluate any preexisting wells within up to a ¼ mile radius of a new proposed well. If potential conduits are identified then there are several options the permit applicant can take. One option is to relocate the well where no other wells fall within the radius of influence. Another option is to demonstrate that the hydraulic fracturing activity will not cause fluid migration up the neighboring well.

In addition to abandoned or degraded wells, there is a possibility for incomplete cementation of the wellbore during well construction. The integrity of the cement bond is evaluated through use of a cement bond log after the well is cemented. Two challenges associated with cementing horizontal wells are associated with (1) solids settling within the drilling slurry resulting in a mud channel along the base of the horizontal leg of a well and (2) excess water in the cement slurry resulting in a water channel along the top of the horizontal leg[68]. Both of these events may compromise the cement casing bond quality along the horizontal segment of the wellbore. These potential challenges highlight the importance of ensuring good cement casing bond quality along the vertical segment in order to prevent leakage along the wellbore.

2.2.4 Driving force for upward fluid migration

A study by Myers[69] suggested a possibility for vertical migration of hydraulic fracturing fluids and formation brines from the Marcellus shale. This finding was related in part to the fact that the study region of the Marcellus is naturally overpressured and the model assumed the existence of a single leakage pathway from the Marcellus to the surface. That is, there is a preexisting natural pressure gradient favoring upward advection of fluids and this gradient was exacerbated by the assumption that hydraulic fracturing would lead to prolonged elevated pressures within the reservoir. Finally, Myers[69] further assumed that the injection of fresh water associated with hydraulic fracturing would dilute the formation water brines to the point that there would also be density-driven vertical flow of the less-dense mixed hydraulic fracturing/formation fluids. However, given that the volume of injected fluid is small relative to that held within the reservoir and overlying formations, prolonged density driven flows induced by the injection of the slickwater would be unlikely.

In a comment on the Myers[69] study, Saiers and Barth[70] argue that the model used by Myers[69] neglects many critical hydrogeological properties and is over simplified to the point that its findings are not applicable to modeling the fate of hydraulic fracturing fluids in the Marcellus. The validity and applicability of Myers' model[69] is further challenged in a comment by Cohen et al.[71] The current technical report does not attempt to evaluate these studies, but points to this academic discussion as evidence of the challenges in accurately modeling complex systems such as that presented by Myers[69]. An important point of discussion here is that the key factor controlling vertical leakage of hydraulic fracturing fluids beyond the target reservoir is the existence (and persistence) of a driving force for upward fluid movement. This is of course in addition to the existence of a potential leakage pathway. Such a driving force could be due to either pressure or density gradients promoting vertical fluid movement. Accurate leakage risk assessment will thus be improved if modeling assumptions can be validated by field data.

Another energy technology that presents many similar environmental concerns in the context of leakage of injected fluids back to the surface is geologic carbon sequestration. The main concept behind carbon sequestration is that CO_2 captured from point source emission sites is injected into the subsurface in an effort to reduce the emissions of CO_2 to the atmosphere. Two key differences between CO_2 leakage risk and the risk of migration of natural gas related to hydraulic fracturing of unconventional reservoirs, are that (1) CO_2 injection creates an overpressured system in the injection aquifer, whereas natural gas production creates an underpressured system and (2) CO_2 injection relies on an intact impermeable caprock to prevent CO_2 leakage, whereas shale-gas production relies on fracturing impermeable formations through hydraulic stimulation. A large body of research has been undertaken in an effort to understand the fate of the injected CO_2 and to assess the risk of CO_2 leakage back to the surface[72–75]. Much attention has been paid to assessing leakage up abandoned wells as these wells can present a conduit to the surface, bypassing layers of impermeable rock[64,65]. It may be beneficial to examine the risk analysis framework used within the CO_2 sequestration research community in future efforts to assess leakage risk related to hydraulic fracturing activities.

2.3 Unconventional reservoir proximity to drinking water resources

Michigan is fortunate in that it has abundant supplies of fresh water. The Great Lakes alone hold approximately 21% of the world's fresh surface water[76]. Added to the fact that fresh water is abundant in Michigan, throughout the Lower Peninsula past glaciation has left the majority of the state's surface covered in a thin layer of unconsolidated sediments. These sediments consist of layers of sand, gravel, and clay. The sand and gravel layers serve as the fresh water aquifers for approximately 21% of residential wells and municipal water withdrawals within the state of Michigan[77]. Larger municipalities, such as Detroit, draw water directly from the Great Lakes and its surrounding waterways (e.g. Detroit River). However, in more rural areas of the state where residential densities are lower there is a higher reliance on shallow subsurface glacial aquifers. For example, the village of Kalkaska has municipal drinking water wells that draw water from glacial aquifers at a depth of 102 feet below the surface[48].

In estimating the proximity of unconventional reservoirs to drinking water resources, it is important to note that the glacial cover is variable and dependent on the exact location of interest. For example,

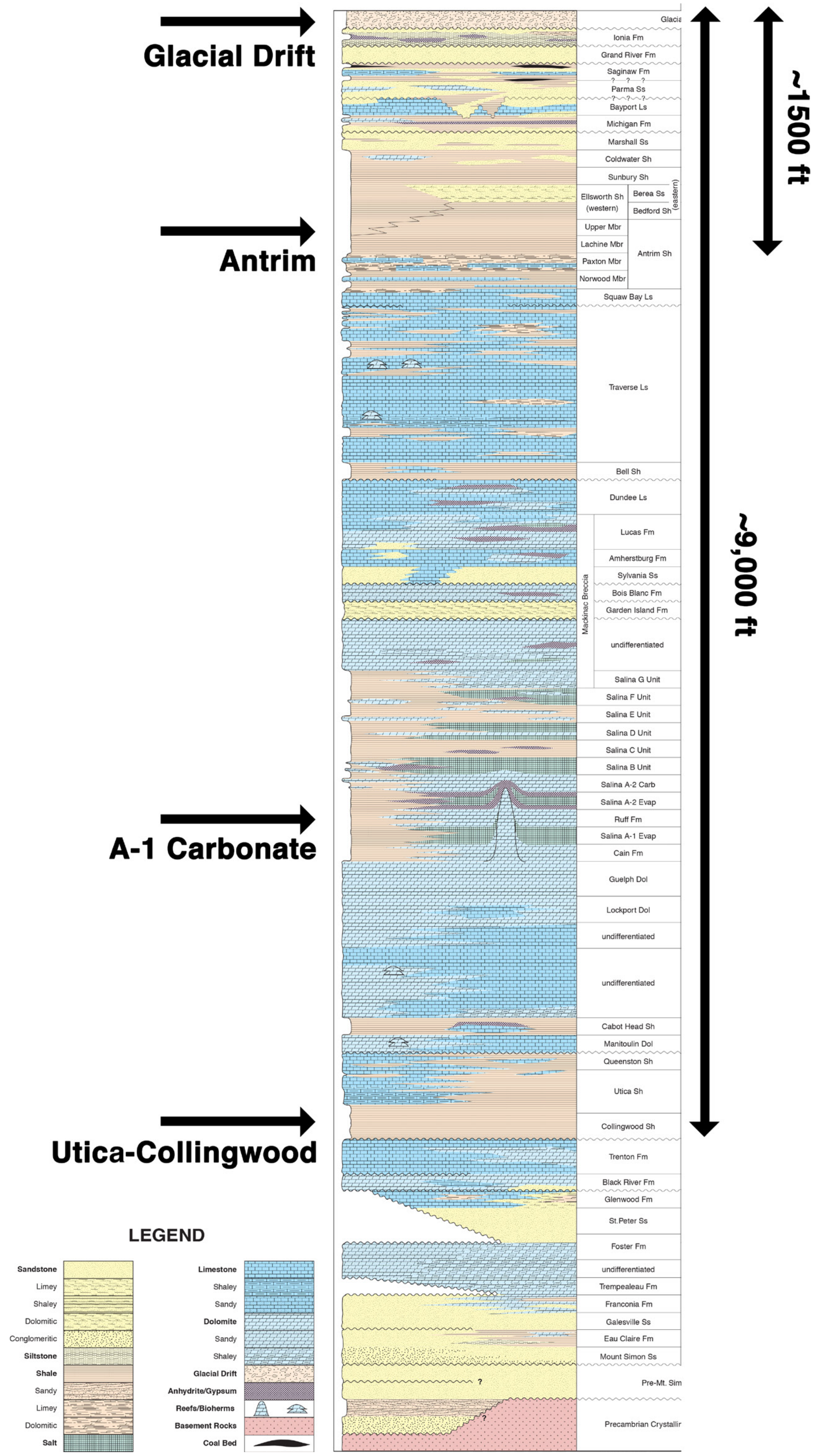


Figure 7: Schematic showing approximate relative locations of Antrim and Utica-Collingwood reservoirs in relation to glacial drinking water aquifers. Distances are approximate and representative of averages depths to top of formation near Kalkaska County, MI. Exact depths will depend on specific location of wells. Figure modified from MDEQ and Michigan Basin Geological Society

some of the thickest zones of the glacial sediment occur near the Northern Producing Trend with thicknesses on the order of 1,000 feet. As discussed previously, most drinking water in Michigan is either sourced from surface waters or from shallow wells that tap into the glacial aquifers at depths generally less than 300 feet. There are also locations in Michigan where drinking water is pumped from the lithic strata, such as in Jackson County where the municipal wells draw drinking water from the Marshall sandstone. But even in this case, the drinking water is pumped from shallow depths (~220 feet) and is due in part to the fact that the glacial sediments are very thin in this area[48].

Given the bowl shape of the Michigan Basin, formations dip downward toward the center of the Lower Peninsula. This means that the exact proximity of each potential target unconventional hydrocarbon reservoir to overlying drinking water aquifers is a function of location within the basin. The Antrim shale is present through most of the Lower Peninsula, subcropping as far north as Cheboygan County and as far south as Lenawee County. The Utica-Collingwood contact is found at depths near 4,600 feet in Charlevoix County and is at its deepest near the intersection of Gladwin, Clare, and Roscommon Counties where it is found at depths just over 10,000 feet below the surface. Moving further south, the Collingwood continues into Gratiot County where it is found at around 8,000 feet deep before it eventually discontinues (see Figure 5). The A-1 Carbonate is found throughout the basin and is also deepest near the center of Michigan's Lower Peninsula, where it is found at approximately 8,000 feet. It is commonly found at depths on the order of 4,500 feet near the northern producing zones of the Niagaran Pinnacle Reef and a recent high-volume completion drilled in Oceana County (Alta-Riley #1-22HD1) targeted the A-1 at a depth of 4,000 feet.

Figure 7 provides a depiction of the relative location of glacial drinking water aquifers to the Antrim, A-1, and Utica-Collingwood. The cross section shown in Figure 7 identifies all formations present in the Michigan Basin. The relative depth to a given formation decreases as one moves outward from the basin center and some of the shallower formations disappear completely (see Figure 1). Figure 7 demonstrates the relative distances between the unconventional reservoirs discussed in this report and is used simply to provide a general idea of where these formations lie with respect to the freshwater aquifers. As discussed above, the exact distance between a given formation and glacial aquifers will be dependent on the specific location within the basin.

2.4 Flowback water chemistry

Hydraulic fracturing of deep horizontal wells often requires large quantities of water (on the order of several million gallons per deep horizontal well[18,78]) that are mixed with small amounts of chemicals (<1%wt) and physical proppants (e.g., sand). This water mixture, referred to as the hydraulic fracturing fluid or slickwater, is injected into the shale to create and hold open zones of high permeability to increase contact with the gas-containing rock. Of the total volume of hydraulic fracturing fluids injected into a well, amounts varying from 10 to 70% may return to the surface

TABLE 1: High-volume well completions in the state of Michigan

Permit #	Well Name	Well No	County	Target Formation	Water Utilized (gal)	*Flowback water (gal)
59112	SCHULTZ	1--36	SANILAC	A1 Carbonate	154,600	121,800
60041	HUBBEL	2-22 HD1	MONTMORENCY	Niagaran	220,000 (est)	34,524
60170	STATE KOEHLER & KENDALL	1-27 HD1	CHEBOYGAN	Collingwood	3,256,596	1,000,902
60212	KELLY ET AL	1-26 HD1	HILLSDALE	Black River	228,312	188,152
60305	STATE WILMOT	1--21	CHEBOYGAN	Collingwood	109,410	15,330
60360	STATE EXCELSIOR	1-13 HD1	KALKASKA	Collingwood	5,860,764	505,386
60380	CRONK	1-24 HD1	GLADWIN	A1 Carbonate	758,454	725,046
60389	STATE EXCELSIOR	1-25 HD1	KALKASKA	Collingwood	8,461,614	615,972
60537	MCNAIR ET AL	1-26 HD1	HILLSDALE	Black River	350,448	3,893
60452	WILEY	1-18 HD1	GLADWIN	A1 Carbonate	1,420,939	1,674,960
60545	STATE EXCELSIOR	2-25 HD1	KALKASKA	Collingwood	12,562,096	64,451
60546	STATE EXCELSIOR	3-25 HD1	KALKASKA	Collingwood	21,112,194	35,202
60560	STATE RICHFIELD	1-34 HD1	ROSCOMMON	Collingwood	4,811,940	1,328,250
60579	STATE GARFIELD	1-25 HD1	KALKASKA	Collingwood	12,539,639	NA
60575	RILEY	1-22 HD1	OCEANA	A1 Carbonate	NA	NA

**Reported flowback volumes account for fluid collected over a period ≤60 days after well completion and this collection period may vary between individual wells. Data from MDEQ[23], accurate as of March 13, 2013. State Garfield data from FracFocus[81].*

as 'flowback water' after the pressure is reduced and gas begins to flow toward the wellhead[78,79]. As shown in Table 1, the average amount of flowback water returning to the surface for high-volume hydraulically fractured wells in Michigan is around 37% of the total injected volumes. This volume may include some amount of native formation brines and is the sum of fluid collected over a period of less than 60 days following completion of the well. The collection periods are not necessary consistent from one well to another, so the flowback data in Table 1 should be considered as approximate values.

The addition of proppants to hydraulic fracturing fluids is to ensure that the fractures remain open after the pressure is released, allowing for continued gas flow in the stimulated area. The chemicals are added to alter the fluid properties of the hydraulic fracturing water in ways that enhance the fracturing process, thus optimizing fracture efficiency and well productivity. Table 2 provides several examples of typical chemical additives used in hydraulic fracturing fluids in Michigan wells. This list is not comprehensive, as the EPA has identified more than 1,000 possible chemicals that may be used in hydraulic fracturing fluids within the U.S.[80] However, most well completions use around 10 different chemical additives in their particular slickwater formulations[81]. Disclosure to regulatory authorities of the particular chemicals and amounts used in the slickwater is not currently required in all states. However, many companies are beginning to voluntarily release this information through the website www.FracFocus.org. As of January 2013, more than 35,000 chemical disclosures have been reported on FracFocus.

A side effect of hydraulic fracturing is the exposure of previously hydraulically isolated minerals that may contain naturally occurring radioactive material and toxic metal elements[82–85]. Some of the possible radionuclides that may be released into formation and hydraulic fracturing fluids include U, Th, and their daughter products ^{226}Ra and ^{228}Ra[82,86]. The half-life of ^{226}Ra, the most stable Ra isotope, is 1600 years. In addition to enhanced levels of radionuclides, flowback fluids may contain elevated concentrations of naturally-occurring salts, metals, organics, and methane[50,87–89]. In Michigan, native formation brine salinities can be on the order of 200–400 g/L total dissolved solids[37]. Evaporite dissolution is believed to be the major driving force in controlling the high brine salinities found in Michigan Basin sedimentary formations.[42,90]

Organic-rich shales in close proximity to drinking water reservoirs have been associated with low-level water contamination due to natural weathering processes causing the release of trace metals to groundwater[91–95]. In trying to identify specific contaminants of concern, the EPA has identified a list of target chemicals to monitor when assessing the adequacy of flowback water treatment. This list includes monitoring of As, Ra, Sr, Ba, U, and BTEX components (benzene, toluene, ethylbenzene, and xylene), among others[80]. Some of these contaminants may be naturally present in the formation brines, so assessment of flowback water quality must take this into account, requiring that baseline measurements be taken prior to drilling activities.

2.4.1 Characteristics of organic-rich shale formations

Black shales, so named for their higher organic carbon content

TABLE 2: Summary of Common Hydraulic Fracturing Chemical Additives Used in Michigan

Application	Chemical Name	Maximum Concentration (% by mass)
Crosslinker	Ethylene Glycol	0.3
Acid	Hydrochloric Acid	0.36
Acid Corrosion Inhibitors	Isopropyl Alcohol	0.3
	Methanol	0.6
Biocides	2,2-Dibromo-3-Nitrilopropionamide	0.6
Friction Reducer	Polyacrylamide, Hydrotreated Light Petroleum Distillate	0.3
Surfactants & Foamers	Glycol Ethers	0.07
	2-Butoxyethanol	.003
Gel Breaker	Ammonium Persulfate	0.6
	Sodium Persulfate	1
Gelling Agent	Guar Gum	1
Iron Control Agent	Citric Acid	1
Proppant	Crystalline Silica, Quartz	0.88
Non-emulsifier	Isopropyl Alcohol	0.4
	Methanol	0.13

Table 2: Common hydraulic fracturing fluid additives used in the state of Michigan. Data were compiled from MSDS reports filed with MDEQ and data posted on FracFocus.org for high-volume fracturing completions. This list is not comprehensive of all potential additives.

and dark color, maintain reducing environments in the subsurface. These reducing conditions can lead to immobilization and subsequent concentration of trace toxic metals and naturally occurring radioactive elements such As and U, respectively[85]. The elements are often bound in sulfide (e.g., FeAsS) and U(IV)-bearing minerals. The naturally occurring higher radioactive content of organic-rich shales has been utilized by the oil and gas industry for detecting promising formations when prospecting for potential shale source rocks during hydrocarbon exploration. The enhanced gamma radiation emission from the shales serves as an indicator for elevated organic content. Figure 4(b,c) shows the correlation of TOC and gamma radiation for the Antrim shale in Michigan.

These organic-rich shales also contain increased concentration of U and Th decay daughter products ^{226}Ra and ^{228}Ra[82,83]. Uranium content of Antrim shale is on the order of 10–40 ppm and scales proportionally with TOC[96]. Trace rare earth and heavy metals are also found at higher abundances in black shales relative to other sedimentary rocks[84,85]. The highest natural concentrations of As (20–200 ppm) tend to be found in organic-rich or sulfide-rich shale formations[91]. Higher concentrations of ^{226}Ra in produced fluids are often correlated with higher salinities, as at higher salinities other metals such as Ca^{2+} outcompete Ra^{2+} for ion exchange sites of the reactive clay mineral surfaces, thereby enhancing the mobility of Ra^{2+} [82]. Positive correlations have also been shown for high concentrations of innocuous salts (e.g., NaCl, $CaCl_2$) and elevated concentrations of trace heavy metals such as Ba[87]. Flowback fluids that come back to the surface include portions of the injected fluids that have reacted with host rock minerals and portions of native formation brines. These native brines may contain elevated concentrations of such elements as Ra and Ba that far exceed drinking water standards[97]. Analyses of flowback waters from hydraulically fractured Marcellus shale wells have found ^{226}Ra concentrations that exceed EPA minimum standards for safe discharge to the environment by a factor of 250 or more[98,99]. This is in addition to the high concentrations of salts and the many hydraulic fracturing chemical additives that return to the surface[78].

2.4.2 Potential contaminant release mechanisms

Although oxygen scavengers are often added to the hydraulic fracturing fluids to prevent pipe corrosion, it is still possible that the injection of oxygen-rich water may lead to oxidative dissolution of reduced mineral phases containing radioactive elements or heavy metals or metalloids, and thereby release more soluble oxidized forms of these elements to the aqueous phase. For example, under reducing conditions, U forms the highly insoluble uranium oxide phases, such as uraninite ($UO_{2(s)}$), but in the presence of oxygen-bearing water $UO_{2(s)}$ can be readily oxidized to highly soluble U(VI) uranyl complexes[100–102]. Because U(VI) forms highly soluble carbonate-calcium- hydroxide complexes in water[103–105], the rate and extent of the oxidative dissolution will also be influenced by the concentration of calcium and carbonate and pH[100]. Likewise, reduced sulfide minerals that contain toxic elements (e.g., AsS or HgS) may be subject to oxidative dissolution, and also serve as a source for increased toxic element release to the flowback fluids. Some examples of this mechanism for iron sulfide phases include the release of As by the oxidation of arensopyrite (FeAsS)[106] or As associated with mackinawite (FeS)[107], depending on pH. Yet another pathway may result from the dissolution or desorption of reduced As from Fe-(oxyhydr)oxide minerals as a result of the change in system redox conditions associated with hydraulic fracturing.[108]

Many of the toxic metals found in shales may also sorb onto the surfaces or into the interlayers of clay minerals[85,108]. Chemical additives that alter clay mineral surface properties may play a key role in determining the fate of sorbed metals. For example, surfactants can alter the mobility of sorbed metal cations. In a study by Hayes et al.[109], divalent cations sorbed to fixed-charge interlayer sites in swelling smectite clays could be released by a series of alkyltrimethylammoniumchloride surfactants (C8TMAC, C12TMAC, and C16TMAC), while those sorbed to external clay surface hydroxyl sites were not impacted. Mono- and poly-cationic amine compounds (e.g. triethanol amine methyl chloride) are also often used in the hydraulic fracturing fluid mixtures as clay stabilizers to prevent swelling of 2:1 clay minerals. These additives compete for sorption sites on the negatively charged clay surfaces and may also impact the release of sorbed metals in shale-gas reservoirs[110].

2.5 Water use in hydraulic fracturing: withdrawal and disposal

2.5.1 Water withdrawal

Typical volumes of water used for high-volume hydraulic fracturing completions are on the order of 2-5 million gallons per well[18,80]; however, a recent high-volume completion in Michigan (State Excelslor 3-25 HD-1) used a reported 21.1 million gallons[81], highlighting the variation among individual well completions. Small hydraulic fracturing completions, such as those used in vertical Antrim wells, use approximately 50,000 gallons of water. To put this water use into perspective, an Olympic size swimming pool holds approximately 660,000 gallons of water. Specific water use for completed high volume hydraulically fractured wells in Michigan is given in Table 1. The actual amount of water needed to finish hydraulically fracturing a given well is a function of the well depth, lateral extent, and number of hydraulic fracturing stages. The topic of water withdrawal as it relates to high-volume hydraulic fracturing activity is covered in greater detail within the Environment/Ecology report (Burton and Nadelhoffer, this series).

Although the amount of water utilized in hydraulic fracturing may be comparable to (or far less than) that used in other industries[18], the volume and short timeframe of extraction may lead to local impacts. Water that is withdrawn from shallow subsurface reservoirs may influence local public water supplies, ecosystems, and compete with other local industries[111]. The MDEQ has issued an instruction requiring use of an online water resource impact assessment tool to evaluate the area of potential adverse resource impact (ARI) prior to any high-volume water withdrawal from subsurface water reservoirs. MDEQ defines an ARI as any withdrawal that (1) reduces stream flow to a point where sensitive fish populations may be adversely impacted due to the reduced flow conditions or (2) reduces surface levels of a body of water to the point where its ability to support characteristic fish populations is functionally impaired. Any well completion that requires withdrawal of more than 100,000 gallons of water per day (averaged over a thirty-day period) must complete such a risk assessment prior to approval or issuance of a drilling permit. See the Environment/Ecology report (Burton and Nadelhoffer, this series) for a more thorough discussion on water withdrawal issues and use of MDEQ's Water Withdrawal Assessment Tool.

2.5.2 Flowback disposal

Disposal of flowback and produced brine fluids in Michigan occurs via deep well injection into brine disposal wells. This method for disposal of produced oilfield brines is very common throughout the U.S.[112] These brine disposal wells are regulated and permitted under the EPA Safe Drinking Water Act through the Underground Injection Control as Class II wells. They are also regulated by the MDEQ under Michigan's Oil and Gas Regulations[66]. Michigan has 1,460 Class II injec¬tion wells in current operation[113]. Of these 1,460 wells, brine disposal wells constitute about half, with the remainder serving other uses such as water injection for enhanced oil recovery or gas injection for natural gas storage. Brine disposal wells are often co-located alongside oil and natural gas production wells. This means that producers in Michigan have a much easier time disposing of hydraulic fracturing flowback fluids than producers in Pennsylvania where only five brine disposal wells are currently in operation[49].

The MDEQ requires that all flowback and produced fluids be contained in aboveground steel containers and reinjected back into the subsurface via brine disposal wells[66]. Open pits are not used for flowback water or produced brine storage[66]. Since flowback is treated as equivalent to produced brine, handling of hydraulic fracturing flowback fluids is no different than handling of produced brine. Most oil and natural gas production wells in Michigan produce copious amounts of brine. This produced water amounted to more than 4.2 billion gallons of brine that was disposed of via brine injection wells across Michigan in 2011. Table 3 relates this total volume of injected brine to the cumulative volume of flowback water associated with high-volume hydraulic fracturing in all completed Michigan Basin wells.

A topic of concern often cited in relation to flowback disposal via deep well injection is a risk of induced seismicity. Recent events such as that in Youngstown, Ohio, where flowback disposal served to lubricate a nearby fault and cause a seismic event, are motivating these concerns[114]. The Michigan Basin has been tectonically stable since the Jurarssic[9] and contains many formations capable of receiving fluid, as evidenced by the prevalence of brine disposal wells throughout the state. Given that brine disposal wells have been actively injecting fluids into the Michigan Basin for many years without any reported incidents of induced seismicity, Michigan has the infrastructure to easily handle the current volume of flowback disposal. A recent study by Keranen et al.[115] identified the potential for a time lag (on the order of years) between the occurrence of fluid injection-induced seismic events and the start of fluid injection in wells located in Oklahoma. These findings support a need for continued monitoring efforts and careful site selection for future brine disposal wells.

One other question related to brine disposal is whether these disposal wells may be altering the local hydraulic gradients and possibly discharging fluids beyond the target injection reservoir. Nearly half of the 712 brine disposal wells in current operation in Michigan inject fluids into the Dundee limestone[23]. As demonstrated in Table 3, this may amount to well over a billion gallons of fluid injected into the Dundee. Closer examination of the ultimate fate of injected fluids and the impact on the local injection formation hydrodynamics would help assuage any concerns surrounding the continued use of these disposal wells.

The amount of flowback water collected from an individual well is highly variable. Table 1 reflects this fact, as can be seen when comparing the volume of water utilized with the volume of flowback collected. As shown in Table 3, high-volume hydraulic fracturing flowback waters currently make up less than 1% of the annual brine disposal volumes (compared to 2011 cumulative disposal volumes). This percentage could change rapidly if there is an accelerated rate of application of high-volume hydraulic fracturing in the state, as was the case for Pennsylvania[116].

TABLE 3: Brine Disposal Wells (BDW) in Michigan

Total operational BDW	712
Total annual volume of injected brine (10^6 gal)*	4200
Total volume flowback water from all high-volume hydraulic fracturing wells (10^6 gal)	6.3
Flowback as % of total brine injection	0.15

**Cumulative 2011 BDW injection data, from MDEQ[23].*

2.5.3 Surface contamination (spills, improper disposal)

Surface contamination likely carries the greatest risk for negative water quality impacts associated with hydraulic fracturing due to the proximity to potable water resources when handling these waste fluids at the surface[117]. However, since in Michigan all flow-back is disposed of via deep-well injection and it is not allowed to sit in open pits, the risk of this type of contamination will be lower than in other states without such disposal opportunities and regulations. The one exception to deep well brine disposal in Michigan is the spreading of produced oilfield brines on dirt roads to control dust.

In a probability bounds analysis by Rozell and Reaven[117], the risk of potable water contamination associated with hydraulic fracturing waste water disposal was found to be several orders of magnitude larger than contamination from other pathways such as contaminant migration through fracture networks. This study was specifically examining the risk of water contamination associated with hydraulic fracturing activities in the Marcellus shale. Handling of waste and production fluids from hydraulically fractured wells in Pennsylvania has been a continuing challenge for natural gas producers. This is primarily due to the fact that the state of Pennsylvania has only five operating brine disposal wells[49], of which only two are commercial wells that accept brine from more than one company (all others are privately owned and operated). This means that producers in Pennsylvania must find alternative solutions to handle flowback water at the surface. Possible options include on-site treatment and reuse or trucking flowback fluids to a site capable of disposing of these fluids (e.g. Ohio brine disposal wells). Flowback waters are no longer accepted at municipal water treatment plants because these plants are not equipped to handle the high salinity brines. Past attempts to treat flowback brines in Pennsylvania have led to contamination of surface waters, prompting the discouragement of this practice[116,118]. Recently, increased application of on-site water recycling and reuse has lessened the surface water handling challenges faced by operators in Pennsylvania[119].

2.6 Common challenges

One challenge related to assessing the impact of hydraulic fracturing on Michigan's water resources is the potentially long timeframe in which the effects of such activity may be recognized. Although a detailed analysis of fluid residence times within the Michigan Basin has not been conducted in this report, the most active groundwater flow regime likely exists in the shallow Quaternary glacial aquifers with minimal interaction with deeper saline formation waters[37]. Additionally, vertical migration of fluids beyond the production reservoirs may also be a slow process even in the presence of flow pathways because of a general lack of a pressure gradient driving force.

Hydraulic fracturing of oil and gas wells has taken place in Michigan for over half a decade without any reported contamination issues. This observation lends credibility to sound industry practices and state regulations within the state of Michigan. However, there may be an opportunity to better characterize subsurface flow regimes in order to build Michigan-specific basin-scale models to investigate fluid residence times and predict the impact on local aquifer hydrodynamics due to brine disposal. This type of modeling effort might serve to better determine the ultimate fate of flowback waters injected into brine disposal wells.

One key challenge that is non-unique to Michigan is the need to determine what chemicals or chemical signatures to test for when investigating migration of fluids beyond the target reservoir. Methane isotopic signatures have been used to evaluate methane origin when testing water wells in Pennsylvania[50], and stable isotopes such as those of Sr have been used to determine the origin of saline fluids[118]. Studies have also investigated the migration of native brines into potable water reservoirs[61] and within flowback water[97]. The study by Haluszczak et al.[97] identified Ra within flowback waters at similar levels to that which would be expected of native formation brines. Advanced analytical techniques (e.g. LC-MS) may be required to identify the degradation byproducts of hydraulic fracturing fluid chemical additives that may accompany leakage of fluids in relation to hydraulic fracturing practices. This is an emerging area of research and will require a concerted effort by industry and the academic research community to identify new tracers to test for when assessing potential cases of potable water contamination.

3.0 PRIORITIZED DIRECTIONS FOR PHASE 2

This last section of the report lists several research areas and topics that could be addressed during the second phase of the integrated assessment. Beyond simply addressing data gaps, it would be beneficial to foster opportunities for improved knowledge transfer and communication among relevant stakeholders.

3.1 Opportunities for additional data collection

3.1.1 Establish baseline water quality data

In order to assess whether there are any water quality impacts associated with hydraulic fracturing in Michigan, baseline water quality data must be gathered from all potentially impacted reservoirs (subsurface drinking water, surface waters). Existing data (e.g. USGS water quality data[120]) could be gathered and aggregated in an effort to establish where specific data gaps exist and prioritize locations for additional water sampling. Implicit within this effort is an assumption that water quality impacts will be detectable if they occur—this requires the establishment of water quality parameters to monitor and determination of chemical tracers explicitly linked to hydraulic fracturing practices. Example parameters might include pH, turbidity, electrical conductance (measure of bulk salinity), and analysis of specific analytes such as Cl^-, Sr^{2+}, Br^- and Ba^{2+}[121]. The Shale Network (www.shalenetwork.org) provides a great example of such an effort to establish a database of baseline water quality data in the Appalachian Basin. The Shale Network seeks to develop a comprehensive water quality database for the region of Marcellus shale development through engaging community volunteers to gather new water quality data and aggregating existing data from government, industry, and academic studies[122]. All of this data is then made publically available through the CUAHSI HydroDesktop server.

3.1.2 Evaluate the impact of hydraulic fracturing chemicals on the release and transport of toxic metals and naturally occurring radionuclides

While flowback fluids are expected to be contaminated to some degree, e.g., it is known that these fluids will be highly saline and contain elevated levels of heavy metals and radioactive elements, in addition the original chemical additives[78,97,99,123–125], their potential to be leached as a function of the shale mineralogy, reservoir conditions (pH, pe, T and P), and chemical additives present in hydraulic fracturing fluid formulations has not yet been determined. Current efforts to monitor flowback and produced water chemistry in other states have focused on characterization of the fluids returning to the surface via standard analytical methods such as ICP-MS, ICP-AES and IC[61,87,99,118,125–127]. Two main conclusions can be drawn from analysis of flowback brines in other states: (1) flowback fluid salinity and concentration of trace inorganic contaminants (e.g., Ba, Ra) increases as a function of time; (2) flowback fluids represent a mixture of injected waters and native brines. One area that has received limited attention is the contribution of the water-rock interactions in controlling flowback fluid chemistry. Prediction of the chemical evolution of remnant hydraulic fracturing fluids or the chemistry of flowback water returning to the surface will be improved if the hydraulic fracturing fluid-shale geochemical reactions occurring in the subsurface are better characterized. It is therefore important to assess whether hydraulic fracturing fluids may enhance the leaching and mobilization of naturally occurring trace elements that may be associated with adverse water quality impacts. If water-rock interactions are found to contribute to the increased toxic metal and radionuclide concentrations in flowback fluids, then it may also be beneficial to determine specific geochemical and mineralogical characteristics of potential reservoir formations that may lead to elevated levels of these constituents.

3.1.3 Monitor fracture propagation

Work to implement standard measurement techniques (e.g. microseismic) for evaluating the extent and direction of major fracture networks during hydraulic fracturing. Gather data from Michigan well completions similar to that presented by Fisher and Warpinski[58]. Industry experience may suggest that shallow Antrim fracturing completions occur only horizontally (so called 'pancake fracs'), but collection of data to verify this would strengthen this claim and better elucidate whether fracture propagation beyond the reservoir is an area of concern for overlying aquifer water quality.

3.1.4 Conduct modeling studies to assess subsurface flow, fluid residence times, and leakage risk

Assessment of leakage risk up existing wells will require some standardized means for structural integrity analysis. The existing efforts by the MDEQ to identify abandoned or improperly sealed wells demonstrate a commitment to addressing leakage risks related to existing wellbores. Additional work on leakage risk assessment and subsurface migration of hydraulic fracturing fluids would be beneficial to understanding the likelihood for fluid migration beyond the target reservoir. Furthermore, it may be worthwhile to take a closer examination of local perturbations of hydraulic gradients associated with brine disposal wells to determine whether brine injection may be pushing fluid beyond the target injection reservoir.

3.2 Reevaluate current regulatory definition of 'produced water'

The key question here is whether flowback fluids should continue to be classified as 'produced water'? Although flowback water associated with high-volume hydraulic fracturing completions currently only makes up a small fraction of the total water produced from oil and natural gas extraction within the state of Michigan, treating it as equivalent to produced brine may be an area that could be reevaluated. It is true that a portion of the flowback fluids is native formation brines[97], but it may also be enriched in other trace contaminants at higher levels than are typically found in produced brines, such as elevated levels of Ba[87]. In addition to containing potentially higher concentrations of toxic metals and radionuclides, many of the chemical additives will return to the surface with the flowback fluid[78]. As a first step, it may be advisable to analyze the flowback water chemistry and compare it with that of the produced brine from older wells nearby. Building a database of native brine chemistry, for instance by aggregating currently available brine data, would also support this effort.

3.3 Facilitate improved dialogue and knowledge transfer among stakeholders

3.3.1 Open dialogue with industry

One obvious shortcoming of this report is the lack of clairvoyance in assessing the potential growth in the application of high-volume hydraulic fracturing within the Michigan Basin. This statement is not meant to be tongue-in-cheek, but instead reflects the author's lack of knowledge regarding industry expectations and plans for future drilling operations in the state of Michigan. Industry players make significant investments to evaluate and develop new resource plays. This knowledge is of course not shared publically nor is it complete. That is, there is always risk that an anticipated reservoir turns out to be less productive than originally hoped. If growth in the application of high-volume hydraulic fracturing can be anticipated, then efforts investigating the potential for adverse environmental impacts could be focused toward the topics or locales of greatest importance. Establishing an open dialogue between industry stakeholders, state-level regulators, and the research community will help guide research efforts moving forward.

3.3.2 Knowledge sharing

Phase 2 of this integrated assessment should leverage the knowledge and experience of seasoned experts within the fields of petroleum engineering and sedimentary/structural geology. Those with the most practical experience are often members of the oil and gas industry. Although developing reports on fundamental topics related to hydraulic fracturing within the Michigan Basin, such as that provided here, represents a good first step toward addressing this complex issue, coordinated involvement of a diverse group of experts will be essential to fully address many of the existing data and knowledge gaps. One suggestion might be to hold a Michigan-centric research colloquium bringing together experts from across the many sub disciplines of relevant fields (e.g. geology, engineering) with interests in and knowledge of the Michigan Basin. Such a meeting would allow for knowledge sharing and consolidation of existing data, thereby enabling a more thorough discussion on the topic of Michigan's geology within the context of hydraulic fracturing.

3.3.3 Need to justify scope of assessment

This report has taken a broad scope when addressing the topic of hydraulic fracturing and has thus included low-volume hydraulic fracturing completions within the context of the report. As was described in the introduction, this was done to provide a more thorough review of formations within the Michigan Basin relevant to unconventional hydrocarbon production. What was not assessed in this report was whether there is or should be a distinction between high-volume and what can be described as more 'traditional' lower-volume well stimulations. Making this distinction clear in the Phase 2 report and assessing the rationale for separating these two practices will make for a more robust discussion of the environmental costs and benefits associated with hydraulic fracturing in general. Advancements in slickwater chemical formations have aided the successful application of high-volume hydraulic fracturing completions. It is the recent application of high-volume hydraulic fracturing well completions, often coupled with directional drilling, that has drawn so much attention to the topic of hydraulic fracturing. By the same logic, one might argue that high-volume hydraulic fracturing is the only technology that should be investigated. Indeed, high-volume hydraulic fracturing is the primary focus of the technical reports compiled during the Phase I portion of this assessment. The general public may not understand the differences between the two practices or may simply choose not to disaggregate one from the other. It is therefore incumbent upon the second phase of the integrated assessment to make a clear case for isolating high-volume hydraulic fracturing within the scope of its analysis. Doing so will provide a necessary transparency to the efforts of the integrated assessment and help educate the lay public as to whether, and why, a distinction should be drawn between the two practices.

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