AN ASSESSMENT OF RISK OF HYDROCARBON OR FRACTURING FLUID MIGRATION TO FRESH WATER AQUIFERS:
CASE STUDY OF COLORADO OIL AND GAS FIELDS

by

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ABSTRACT

The United States National Science Foundation, engaging 29 researchers at nine institutions, has funded a Sustainability Research Network (SRN) focused on natural gas development. The mission is to provide a science-based framework for evaluating the environmental, economic, and social trade-offs between development of natural gas resources and protection of water and air resources.

There are a series of independent events that must occur to allow hydrocarbon or fracturing fluid migration to fresh water aquifers. A statistical analysis of data from 36,682 oil and gas wells, from four main basins in Colorado, was made to demonstrate the low rate of complete wellbore failures that resulted in hydrocarbon or fracturing fluid contamination. These results will help shape the discussion of the risk of oil and gas development and will assist in identifying areas of improved well construction and hydraulic fracturing practices to minimize the risk of aquifer or surface soil contamination.
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LIST OF SYMBOLS

Carbon 12 ................................................................................................................... $^{12}$C
Carbon 13 ................................................................................................................... $^{13}$C
Carbon Dioxide ......................................................................................................... CO$_2$
Cement Bond Log ..................................................................................................... CBL
Colorado Oil and Gas Conservation Commission .................................................. COGCC
Cubic Feet .................................................................................................................... ft$^3$
Drilled and Abandoned ........................................................................................... DA
Feet .............................................................................................................................. ft
Hydrochloric Acid ....................................................................................................... HCl
Hydrogen Sulfide ........................................................................................................ H$_2$S
Potassium Chloride .................................................................................................... KCl
Mechanical Integrity Test ........................................................................................... MIT
Mile ............................................................................................................................... mi
Milligram per Liter ..................................................................................................... mg/L
Notice of Alleged Violation ..................................................................................... NOAV
Plugged and Abandoned ........................................................................................... P&A
Pound per Square Inch (Force) ................................................................................... psi
Sustained Annulus Pressure ..................................................................................... SAP
Top of Cement ............................................................................................................ TOC
Total Dissolved Solids ............................................................................................... TDS
True Vertical Depth .................................................................................................... TVD
United States Geological Survey ............................................................................. USGS
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CHAPTER 1
INTRODUCTION

The prevention of contamination of fresh water aquifers has been a prime concern in drilling operations since the inception of drilling in China for salt 5,000 years ago. Surface casing has long been the primary barrier to prevent contamination through wellbores, with hollowed logs first used as surface casing by the Chinese (Kuhn 2004). The probability of leakage from wellbores during shale development into aquifers has a wide range of estimates (Ingraffea et al. 2014; Watson and Bachu 2007), complicated by the presence of hydrocarbons at shallow depths in many parts of the world (Heisig 2013). Early oil and gas wells were typically drilled to very shallow depths, with hydrocarbons intermingled with fresh water aquifers. The first US shale gas well was drilled in Fredonia, New York, in 1821 to depth of 28 ft. The first US oil well was drilled in 1859 in Titusville, Pennsylvania producing oil from a depth of 69 ft.

This study examines the contamination of aquifers in the subsurface during the completion and the production phases of the well and demonstrates the low risk of contamination of aquifers through complete failure of the wellbore. It is proposed that there are a series of independent barrier failures, each of which must occur for contamination of fresh water aquifers, either by migration of hydrocarbons or by contamination during hydraulic fracturing operations. During the production phase of the well, subsurface barrier(s) are often redundant and nested in the event of a primary barrier failure. During the completion phase of the well, the independent barrier failures during the production phase of a well must happen plus additional pressure monitoring barrier failures for contamination of the aquifer to take place during the hydraulic fracturing process.

There are a wide range of estimates of the risk of complete wellbore barrier failure from a variety of studies (Fleckenstein et al. 2015, Ingraffea et al. 2014; Vidic et al. 2013). There may be some question of the exact risk of complete wellbore barrier failure, but it is obvious that if the independence of each barrier failure event is maintained, the risk of migration of hydrocarbons to an aquifer is low and the risk of
fracturing fluid contamination of an aquifer is extremely low. This study will show the statistics of independent barrier failures and complete wellbore barrier failures in the State of Colorado.

1.1 Overview of Colorado Oil and Gas Basins

Oil and gas bearing formations in the State of Colorado were deposited during transgressions and regressions of the Western Interior Seaway during the Cretaceous geologic time period 145 million years ago. Early oil and gas development in the state began in 1862 near Florence, but it dramatically increased statewide after 1970. There are four main oil and gas basins in Colorado: Denver-Julesburg Basin which contains the Wattenberg Field, Piceance Basin, Raton Basin and San Juan Basin (Figure 1.1). The majority of oil and gas development in the State of Colorado is centered either in the Wattenberg Field or the Piceance Basin. Each basin has unique geologic conditions and fresh water aquifer systems. Due to these dissimilarities, diverse wellbore designs were implemented throughout the development of oil and gas wells in the state. More recent wellbore designs often present less risk of failure than older legacy wellbore designs due to current oil and gas regulations, technological advancements and industry experience.

![Figure 1.1 Geographic locations of oil and gas basins in the State of Colorado.](image)
Data was gathered from the Colorado Oil and Gas Conservation Commission (COGCC) facility database for 36,682 oil and gas wells in the State of Colorado to assess the risk of hydrocarbon or fracturing fluid migration to fresh water aquifers or surface soil. 17,948 wells, drilled between 1970 and 2014, are located in the Wattenberg Field – Denver Julesburg Basin, 10,998 wells, drilled between 1935 and 2014, are located in the Piceance Basin - Garfield County, 3,547 wells, drilled between 1920 and 2013, are located in the Raton Basin, Colorado, and 4,189 wells, drilled between 1901 and 2014, are located in the San Juan Basin, Colorado.

1.2 Barrier Definition

A well barrier “will prevent a formation’s liquid or gas from flowing to the surface or another formation” (API RP 90). According to the Standards Norway, the definition of well integrity is the, “application of technical, operational, and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well” (Standards of Norway 2004). Wellbores are engineered to have many barriers in place to protect the environment.

There are two main types of barriers: static and dynamic. Static barriers are available over a long time period and are constant. Examples of static barriers include casing, cement, packers, and tubing. Dynamic barriers, which include drilling fluids, pressure monitoring gauges and well control equipment, will vary over time. Barriers can be passive or active. A passive barrier means no human actions are needed to implement the barrier, such as the inherent density of a fluid exerting a hydrostatic pressure. An active barrier needs a human or control system in action to engage. The closing of a blow-out preventer ram during drilling operations is an example.

For a producing well, it is imperative that barriers exist over time to prevent the migration of fluids from a hydrocarbon bearing zone to the surface or subsurface environment. This is accomplished in the wellbore construction process primarily with casing and cement. Other barriers would include the pressure monitoring equipment, wellhead, tubing, packers, and the completion fluid inside the production casing/tubing annulus as well as any fluid in other annuli. During fracture-stimulations, an active barrier is added at the wellhead, a frac valve, and there is active monitoring of the
pressures both in the fracture fluid stream and in any annulus between the fracture string and other casing strings. The typical unconventional resource well slated to be fracture-stimulated includes the following barriers: surface casing cemented to surface, production casing, production cement, wellhead, annular fluids and pressure monitoring equipment. In addition, tubing and packers inside the production casing string can serve as additional barriers in applicable wells.

Not all wellbore barriers are created equal. During the production phase of a well, barriers are passive in nature (King and King 2013). Carbon-steel casing is extremely durable and is a passive-static barrier. Cement, which is also a passive-static barrier, is used to create a seal in the annulus around the casing and further re-enforce the strength and durability of the casing. Hydrostatic pressure from drilling mud, formation water and fresh water in the annulus above the top of the cement is an additional passive-dynamic barrier to prevent hydrocarbon migration in the annulus. In addition, pressure monitoring of the annulus during the production phase is common in wellbore designs. Not all designs are the same and there is no one-size-fits-all barrier failure frequency (King and King 2013). Common vertical, deviated and horizontal subsurface wellbore barrier designs were grouped and ranked based on risk of multiple barrier failures (Figure 1.2). For the sake of clarity, pressure monitoring of the casing annulus will not be assumed to be an additional barrier during the production phase, even though it is frequent and often required by state regulations.

Higher risk wellbore barrier designs have a single subsurface annular hydrostatic barrier preventing hydrocarbon or fracturing fluid migration to a fresh water aquifer. A category 1 well barrier design has the highest risk of barrier failure due to the surface casing setting depth above the base of the fresh water aquifer and only a single annular hydrostatic pressure barrier preventing hydrocarbon migration from an over-pressured formation (Figure 1.3).

A lower risk design will include four independent subsurface barriers to prevent hydrocarbon migration. A category 7 well barrier design has surface casing set below the base of a fresh water aquifer, which is cemented to surface, production casing and a production cement top (TOC) above the surface casing shoe. This well design doesn't rely on annular hydrostatic pressure as a barrier (Figure 1.4, see page 7).
Well barrier designs can vary from field-to-field based on the geology, trajectory, depths, anticipated pressures, expected hydraulic treatment rates and estimated production rates. Whether a well is horizontal, vertical or deviated plays no significance on the ultimate protection of fresh water aquifers since the wells are designed to protect the shallow vertical section of each oil and gas well. Multiple barriers must be in place near the depth of the fresh water aquifer in order to prevent breaching of a single barrier and ultimately leading to contamination. All wells in the study have been categorized based on their original wellbore designs and subsequent current designs after any remediation work.

Figure 1.2 Wellbore barrier categories that are ranked from highest risk to lowest risk.
Figure 1.3  Example of a high risk wellbore barrier design.
Figure 1.4 Example of a low risk wellbore barrier design.
1.3 Failure Definition

There is a wide-range of definitions and estimates of wellbore failures (Ingraffea et al. 2014; King and King 2013). They all have commonality in definitions: the breaching of one or more barriers. For this study, there exist two types of barrier failures: potential barrier failures and catastrophic barrier failures. The definitions of these failures are as follows:

Potential barrier failure is the breakdown of a single or multiple barriers in a wellbore that didn’t result in the contamination of fresh water aquifers or surface soil from hydrocarbon or fracturing fluid migration but required remediation of the failed barrier(s) in order to further enhance the nested barrier system of the well.

Catastrophic barrier failure is the breakdown of a combination of various wellbore barriers (casing, cement and hydrostatic pressure of annular fluids) protecting fresh water aquifers during hydraulic fracturing or production phases of a well cycle resulting in the contamination of the fresh water aquifers or surface soil. This contamination is detected by the isotopic and compositional analysis of hydrocarbons or fracturing fluids in offsetting water wells or in the surrounding surface soil.
Aquifer systems frequently contain natural gas. This observation is due to naturally occurring biogenic methane created in the aquifer system, methane from coal deposits within the aquifer system, or from migration of hydrocarbons from deeper and more mature formations. It is important to distinguish the differences between inherent methane presence in the aquifer system and hydrocarbon migration from deeper formations. Hydrocarbon or fracturing fluid migration is dependent on the path of least resistance in a wellbore. There are three events that must take place in order for uncontrolled migration to materialize: a leak source, a driving force and a leakage pathway (Watson and Bachu 2007). This flow path can transpire due to a failure of a barrier in the production casing, the casing annulus or through natural hydrocarbon migration, over geologic time, through separate formations.

2.1 Hydrocarbon Migration Flow Paths

In order for hydrocarbon migration to transpire, there must be a direct flow path to the aquifer. This can occur through two main flow paths: a failure of the production casing or a failure in the casing annulus (Watson and Bachu 2008). A primary barrier in a well is the production casing which is made of carbon-steel. This casing is designed and manufactured to have high tensile strength, elevated burst ratings and lower collapse ratings. The casing body is durable and engineered to withstand thermal-stress fluctuations, cyclic stress loading and pressure differential. Typical wells have production casing, which has a stronger alloy composition, but can be susceptible to corrosion due to its metallurgical properties. Common corrosion of casing is caused by corrosive gas, CO₂ or H₂S, in the produced gas stream, which is comingled with high salinity and high quantities of Total Dissolved Solids (TDS) in the formation water. The salinity of the produced water increases with age which raises the chance of carbon-steel corrosion without proper monitoring and corrosion inhibiting treatments leading to a barrier failure from anodic deterioration of the pipe wall. The corrosion holes, or
Pitting, generally occur at shallow depths, above the TOC of the production casing due to lower pressure and temperature conditions (Papavinasam 2014). In addition to corrosion related leaks, a potential leak source is characteristically located at the connections of the production casing if improper pipe sealant (pipe dope) is used or thread galling arises during the initial installation phase (King and King 2013).

If the production casing barrier fails, additional barriers exist to prevent hydrocarbon migration to fresh water aquifers. The hydrostatic pressure in the annulus combined with the deep surface casing below the fresh water aquifer base act as redundant barriers in the event of a primary barrier failure. If the surface casing is not set below the base of the aquifer, than a direct flow path can be created with only hydrostatic pressure preventing hydrocarbon migration.

An indication of a barrier failure with possible hydrocarbon migration is sustained annulus pressure (SAP), sometimes called Bradenhead pressure. Wells are monitored for such events with pressure gauges attached to the wellhead to measure annulus pressure buildup. This pressure monitoring adds an additional barrier to the overall barrier system. During the observance of SAP, operators can bleed down the pressure at surface and proceed to perform mechanical integrity tests (MIT) on the subsurface to isolate potential leaks and identify the sources of the hydrocarbon migration or fluid pressure buildup in the annulus (Rocha-Valdez et al. 2014). If a breach in the production casing barrier is detected, remedial cement operations will add an additional barrier and eliminate the annulus pressure buildup.

A second flow path can occur in the annulus, or behind the production casing. This flow path is often created by improper design, contamination or height of the production cement. The production TOC must cover all existing hydrocarbon bearing formations. The production casing must also be centralized in order to have a proper cement sheath and effective cement isolation. Cement bond logs (CBL) show that cement is not always uniform behind the pipe. Studies have demonstrated that a flow barrier is created with a minimum of 5 – 50 ft of suitable annular cement coverage (Brown et al. 1970; King and King 2013). If the production TOC is not covering all existing hydrocarbon bearing formations and surface casing is not set below the base of the fresh water aquifer, then a direct flow path can transpire to the aquifer. The annular
fluid, or hydrostatic pressure, becomes the only barrier preventing hydrocarbon migration.

2.2 Thermogenic Gas and Biogenic Gas in Fresh Water Aquifers

There are two forms of natural gas below ground level: biogenic (microbial methane) and thermogenic gas. The characteristic and composition of both forms of gas differ based on the components of the natural gas and analytical measurements of the C\textsuperscript{12} and C\textsuperscript{13} stable isotopes. A study of methane in groundwater was done by the United States Geological Survey (USGS) in a 1,810-square-mile area of south-central New York along the Pennsylvania border. The study reported that “results of sampling indicate that occurrence of methane in groundwater of the region is prevalent, occurring in 78% of the groundwater samples (Kappel and Nystrom 2012).

Another study performed by Li and Carlson 2014, states that biogenic methane gas naturally occurs in fresh water aquifers due to subsurface bacteria and is usually found due to high carbon concentrations and low redox potential. This process of creating biogenic gas is through two methods: acetate fermentation and CO\textsubscript{2} reduction (Li and Carlson 2014). Biogenic gas has more C\textsuperscript{12} stable isotopes than thermogenic gas. Thermogenic gas is produced through thermal cracking in deeper formations where higher pressure and temperature conditions exist. The thermogenic gas has more C\textsuperscript{13} stable isotopes than biogenic gas (King 2012). This is useful to determine whether gas found in aquifers is naturally occurring in the aquifer, or has migrated from a deeper hydrocarbon source.

There are two main pathways for thermogenic gas to breach a fresh water aquifer: natural seepage through faults or natural fractures or through faulty barrier systems in oil and gas wells. In 2013, the COGCC issued rule 318A.e. which states that groundwater sampling must be collected from two sources within a 0.5-mile radius prior to drilling an oil and gas well in order to create a baseline analysis, and after the well is on production to detect changes in the baseline. If a water well test indicates methane concentrations greater than 1.0 mg/L, then further testing is required to determine the origin of the gas.
2.3 Fracturing Fluid Migration to Fresh Water Aquifers

There is a common public misunderstanding of the risk of aquifer contamination due to hydraulic fracturing operations. As previously mentioned, methane is naturally present in fresh water aquifers and the source of the methane is of principle concern. Testing of water wells can indicate the presence of biogenic or thermogenic gas, but have little to no evidence of barrier failures that led to fracturing fluids migrating to a fresh water aquifer based on the composition of the fracturing fluids. Wells are hydraulically fractured at very deep depths with thousands of feet of rock between the aquifer and the hydraulically fractured formation.

During hydraulic fracturing operations, there are several reasons fracturing fluids have extremely low risk of contaminating fresh water aquifers: 1) the depth of the hydraulically fractured formation 2) the pressure monitoring of production casing and annuli 3) the potential flow path of the fluid 4) the short duration of time hydraulic fracture operations occur 5) the strength of the passive-static barriers.

The hydraulically fractured formations are generally greater than 4,000 ft below surface. On average, ninety-eight percent of the fracturing fluid pumped down the production casing is fresh water and the remaining two percent of the total volume is composed of hydrochloric acid (HCl), friction reducers, surfactant, potassium chloride (KCl), biocide, guar gel, and various additives. Most of these additives are in household cleaning products, medications and various cosmetics (Figure 2.1) (US DOE 2009). The fracturing fluid is typically pumped down the casing and out perforations connecting the wellbore to the formation to be stimulated. The initiated fractures create a fracture network that are contained within the zone of interest with higher compressive strength rock above that inhibits fracture height growth. Confirmed by micro-seismic monitoring during hydraulic fracturing, this typical height growth is generally limited to 300 ft or less (King 2012).

During hydraulic fracturing operations, pressure gauges are installed on the wellhead that monitor in real time, the pressure of the casing and the annulus. The production casing has a high burst rating and treatment pressure is designed to not exceed this burst rating, with an additional safety factor. If any abnormal pressure is detected in the annulus, pumping stops immediately and pressure testing of all casing
and equipment is performed. An increase in annular pressure during hydraulic fracturing operations can be caused by poor cement placement or quality in the annular space, if the integrity of the production casing is intact. Cement in the annulus between the production casing and the wellbore can be contaminated during the initial bonding stage due to gas migration, improper centralization or fluid contamination. Prior to fracking a well, a CBL is typically run to determine the quality and height of the cement in the annulus.

Figure 2.1 Typical composition of hydraulic fracturing fluids and their common uses in commercial products (US DOE 2009).

<table>
<thead>
<tr>
<th>Fracturing Ingredients</th>
<th>Main Ingredient</th>
<th>Purpose</th>
<th>Other Common Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Product Category</strong></td>
<td><strong>Main Ingredient</strong></td>
<td><strong>Purpose</strong></td>
<td><strong>Other Common Uses</strong></td>
</tr>
<tr>
<td>Water</td>
<td>~98%</td>
<td>Expand fracture and deliver sand</td>
<td>Landscaping and manufacturing</td>
</tr>
<tr>
<td>Sand</td>
<td>water &amp; sand</td>
<td>Allows the fractures to remain open so the gas can escape</td>
<td>Drinking water filtration, play sand, concrete and brick mortar</td>
</tr>
<tr>
<td>Acid</td>
<td>Hydrochloric acid or muriatic acid</td>
<td>Helps dissolve minerals and initiate cracks in the rock</td>
<td>Swimming pool chemical and cleaner</td>
</tr>
<tr>
<td>Biocide</td>
<td>Glutaraldehyde</td>
<td>Eliminates bacteria in the water that produces corrosive by-products</td>
<td>Disinfectant; Sterilizer for medical and dental equipment</td>
</tr>
<tr>
<td>Breaker</td>
<td>Ammonium persulfate</td>
<td>Allows a delayed break down of the gel</td>
<td>Used in hair coloring, as a disinfectant, and in the manufacture of common household plastics</td>
</tr>
<tr>
<td>Corrosion Inhibitor</td>
<td>n,n-dimethyl formamide</td>
<td>Prevents the corrosion of the pipe</td>
<td>Used in pharmaceuticals, acrylic fibers and plastics</td>
</tr>
<tr>
<td>Crosslinker</td>
<td>Borate salts</td>
<td>Maintains fluid viscosity as temperature increases</td>
<td>Used in laundry detergents, hand soaps and cosmetics</td>
</tr>
<tr>
<td>Friction reducer</td>
<td>Petroleum distillate</td>
<td>“Slicks” the water to minimize friction</td>
<td>Used in cosmetics including hair, make-up, nail and skin products</td>
</tr>
<tr>
<td>Gel</td>
<td>Guar gum or hydroxyethyl cellulose</td>
<td>Thickens the water in order to suspend the sand</td>
<td>Thickener used in cosmetics, baked goods, ice cream, toothpaste, sauces and salad dressings</td>
</tr>
<tr>
<td>Iron control</td>
<td>Citric acid</td>
<td>Prevents precipitation of metal oxides</td>
<td>Food additive; food and beverages; lemon juice ~7% citric acid</td>
</tr>
<tr>
<td>Clay stabilizer</td>
<td>Potassium chloride</td>
<td>Creates a brine carrier fluid</td>
<td>Used in low-sodium table salt substitute, medicines and IV fluids</td>
</tr>
<tr>
<td>pH adjusting agent</td>
<td>Sodium or potassium carbonate</td>
<td>Maintains the effectiveness of other components, such as crosslinkers</td>
<td>Used in laundry detergents, soap, water softener and dishwasher detergents</td>
</tr>
<tr>
<td>Scale inhibitor</td>
<td>Ethylene glycol</td>
<td>Prevents scale deposits in the pipe</td>
<td>Used in household cleansers, de-icer, paint and caulk</td>
</tr>
<tr>
<td>Surfactant</td>
<td>Isopropanol</td>
<td>Used to increase the viscosity of the fracture fluid</td>
<td>Used in glass cleaner, multi-surface cleansers, antiperspirant, deodorants and hair color</td>
</tr>
</tbody>
</table>

*Source: US DOE, Modern Shale Gas Development in the United State, Exhibit T 36: Fracturing fluid additives, many compounds, and common uses.*
King (2010) found no documented cases of fracturing fluids migrating to fresh water aquifers or to surface soil for formations hydraulically fractured greater than 2,000 ft below ground level. This study also found no evidence of fracturing fluid migration to fresh water aquifers out of 36,682 wells in the data set from the four main oil and gas development basins in Colorado. The majority of wells included in the study that were eventually turned to production, are considered unconventional. They require some form of artificial stimulation, in order to be economic.
CHAPTER 3  
METHODS, DATA ASSUMPTIONS AND ERRORS

The COGCC maintains an online repository of up-to-date well data for the State of Colorado. Documentation is provided for each well from initial permitting to the current status of the well. Information related to remedial cementing, offset monitoring wells, SAP, wellbore construction methods, and geologic formations can be found in this documentation and was used for this assessment.

3.1 Methods
Current and original wellbore configurations were taken from the scout cards that are available for each well on the COGCC facility database. This includes completion dates, locations, casing setting depths, casing specifications, quantity of cement, wellbore diameters, initial cement depths based on CBLs, formation tops, and the depths of any remedial cementing that has been performed. Each scout card is for a specific well and the data is directly supplied from the operator of the oil and gas well to the COGCC. Each well was assigned a wellbore barrier category based on the number of casing strings, casing setting depths and cement tops for each casing string related to formation tops. If any cement remediation was performed on a well, a new applicable category was assigned to the well based on its post-remediation wellbore barrier design.

The Notice of Alleged Violation (NOAV), referred to as a violation in this study, is a form issued to operators that are suspected of being in violation of the rules enforced by the COGCC. These forms offer descriptions of the alleged violation and can be indicative of hydrocarbon migration directly caused by an individual oil and gas well. The NOAV data was collected from the COGCC database. Text-based search queries were used to identify NOAVs relevant to this assessment. Once identified, corroborating data was located before the well was classified as a catastrophic barrier failure. This data came in the form of isotopic and compositional hydrocarbon analysis, official communications between interested parties, and other published documents.
COGCC orders document the official hearings that are subsequent to a NOAV filing. These orders are made available by the COGCC and offer text-based searching. Orders were searched and analyzed in a similar manner as the NOAVs. Search queries were used to identify wells that have been the source of subsurface hydrocarbon migration in the field. Since the orders represent a terminus of the rule enforcement process, no corroborating data was needed to classify these wells.

In addition to the NOAV forms, mechanical integrity test (MIT) results and public complaints served as markers for potential instances of hydrocarbon migration to surface soil or fresh water aquifers. This data is made publicly available by the COGCC. The same text queries were used to identify wells of interest. Supporting data was located to ensure proper classification of these wells.

Additional studies on the four basins under analysis were used to classify potential barrier failures and catastrophic barrier failures. Independent studies on water wells, observed SAP in oil and gas wells and geologic conditions were used to further enlighten the root causation of hydrocarbon or fracturing fluid migration to fresh water aquifers or surface soil. Additional proprietary well information was provided by an independent operator for the Piceance Basin. This data included gas analyses, corrosion prevention data and cement remediation data. No additional independent data was supplied by other operators for this study.

3.2 Data Assumptions

Data collected from the COGCC online repository can be incomplete on older wells due to inadequate well files supplied by the operator. If the TOC in a well is not clear or appears inaccurate, the quantity of cement and wellbore geometry were used to estimate the top of cement in the annulus. The assumed yield for intermediate and production cement was 1.18 ft³/sack of cement. The top of gas was assumed to be any formation with commercial quantities of hydrocarbon accumulations, which is referred to as the top of gas in this study and follows the rules governed by the COGCC. If this formation top was not supplied by an individual scout card, then an average depth of the upper-most hydrocarbon bearing formation was assumed by correlating an average depth of the formation and projected based on the topographic elevation of the oil and gas well.
Fresh water aquifer depths were given in the Wattenberg Field based on depth contours of the Fox-Hills aquifer from ArcGIS online (ArcGIS 2016). For the Piceance Basin, Raton Basin and San Juan Basin, there isn’t a defined base depth of the aquifer system similar to the Wattenberg Field. The maximum depth of the fresh water aquifers in these basins was determined by the water well depths and locations collected from the COGCC water well database and mapped utilizing TIBCO Spotfire. For the Raton Basin and San Juan Basin, shallow and deep surface casing assumptions were used in relation to the depths of offset water wells within a 0.5-mile radius of an oil and gas well or the average water well depths across the field for oil and gas wells not within a 0.5-mile radius of a water well which is similar to current COGCC regulations. Shallow surface casing is defined as being set below the base of the aquifer or shallower than the deepest water well that is within 0.5-mile radius of an oil and gas well; whichever is deeper. For the Piceance Basin, 73% of the water wells supplied by the COGCC water well database were missing depths. Therefore, the maximum water well depth of 600 ft was used as a marker defining shallow and deep surface casing.

A small sample-set of exploratory oil and gas wells, that were drilled prior to 1950, lacked wellbore construction data. These wells were omitted in the study after determining that they didn’t have a catastrophic barrier failure. Drilled and abandoned (DA) wells were not included in this study besides their well counts and locations. These wells were assumed to be plugged and abandoned (P&A) in accordance to COGCC regulations. Orphaned abandoned wells that were not in the COGCC database were also omitted in this study unless they were determined to be catastrophic barrier failures. Wells that were drilled to total depth, completed and were placed on production are the only wells included in this study.

Subsurface barriers were defined as casing, cement or annular hydrostatic pressure. Additional barriers not included in the production phase assumption include pressure monitoring gauges, wellhead equipment and tubing and packers. However, during the hydraulic fracturing phase of a well, pressure monitoring of the fracture fluid string and casing annulus will be assumed to be additional barriers.

Potential barrier failures were identified by cement remediation below the surface casing shoe in the Wattenberg Field and by cement remediation on any casing string for
the Piceance Basin, Raton Basin and San Juan Basin. It is common in the Wattenberg Field to re-fracture existing formations or new formations and many older wells receive cement remediation prior to re-fracturing treatments in order to comply with current COGCC rules and regulations. Therefore, only cement remediation performed below the surface casing shoe in the Wattenberg Field were defined as potential barrier failures.

The reason for the cement remediation could be directly ordered by the COGCC due to the violation of existing rules on cement placement, insufficient casing depths or from the observed SAP. The assumption for this study is to assume that any of these various reasons for cement remediation jobs were due to a barrier failure and were identified as potential barrier failures.

Catastrophic barrier failures were identified by violations issued by the COGCC to an operator for violating rules to prevent contamination of fresh water aquifers or surface soil. If the COGCC was inconclusive on its findings and evidence existed that an off-set oil and gas well had SAP, coupled with evidence of thermogenic gas sampled in an offset water well, then the oil and gas well was assumed to be a catastrophic barrier failure for this study.

### 3.3 Errors

Under the data assumptions provided, there exist potential errors that can lead to inaccurate categorization of the oil and gas wells. Any missing data point on an individual oil and gas well scout card within the COGCC database, require certain assumptions that can be inaccurate for proper wellbore barrier categorization. If the top of cement is not listed, or appears inaccurate based on the quantity of cement pumped, then an estimated top of cement was calculated based on the quantity of cement, a yield of 1.18 ft³/sack of cement and a uniform wellbore geometry. The yield for the cement was not provided in the scout card and wells utilize a variety of cement types that all have different yields. In addition, a uniform diameter wellbore was assumed with no washouts. Due to these assumptions, the estimated top of cement can be in error. Under the calculated cement top assumption laid out in this study, the top of cement could be lower or higher than actuality.
Error can also be due to missing depths of formation tops for certain older wells, supplied on an individual well’s scout card, for the top of gas designation for a specific well. The assumption in this study is to take the average depth of the top of gas based on the formation tops supplied on the scout cards for all wells in the basin and projecting an individual well’s formation top based on topographic elevation. This assumption can be inaccurate due to erosion or structural alterations subsurface. By assuming the top of gas for wells that were lacking this data, improper wellbore barrier categorization can exist.

Wellheads, production pressure monitoring, tubing and packers, which can add additional barriers to the wellbore barrier system, are also ignored due to simplification or lack of data. Certain higher risk wellbore barrier categories can contain all or some of these additional barriers which explains differences in potential barrier failure rates and catastrophic barrier failure rates for high risk wellbore barrier categories.

Aquifer depths were supplied for the Wattenberg Field. However, the base depths of the aquifer systems in the Piceance Basin, Raton Basin and San Juan Basin were not well-defined by a geologic barrier. Shallow and deep surface casing designations were based on the deepest offset water well depth within a 0.5-mile radius from an oil and gas well in all basins. For oil and gas wells that were not within a 0.5-mile radius of a water well, then the average water well depth in the field was used as a marker defining shallow and deep surface casing in the Raton Basin and San Juan Basin. The maximum water well depth of 600 ft was used in the Piceance Basin as the marker for shallow and deep surface casing categorization. Due to the lack of information related to aquifer base depths in the Piceance Basin, Raton Basin and San Juan Basin, the assumed aquifer base depths can be inaccurate, but the assumptions laid forth are similar to current COGCC regulations.
The Wattenberg Field, located in the Denver-Julesburg Basin, Colorado primarily began oil and gas exploration in 1970. The field is the most active oil and gas field in Colorado and is bordering the highest population of the state in the Denver metro area (Figure 4.1). There are four main producing formations in the field from deepest deposition to shallowest deposition: Muddy-J, Codell, Niobrara and the Shannon-Sussex Formations. Vertical and deviated wells were drilled until 2010, when horizontal wells became the principal well design. These horizontal wells primarily target the Niobrara and Codell Formations. Data from 17,948 oil and gas wells in the Wattenberg Field was analyzed to determine the risk assessment of barrier failure and the overall risk of contaminating fresh water aquifers from hydrocarbon or fracturing fluid migration.

Figure 4.1 Geographic location of the Wattenberg Field, Colorado.
4.1 Wattenberg Field Geology

The Wattenberg Field located in the Denver-Julesburg Basin, was deposited in the Late Cambrian and Early Ordovician time, in shallow marine environments (Kent 1972). The Western Interior Seaway submerged the basin during the Cretaceous period, with sea levels transgressing and regressing throughout time. On the western flank of the basin are the Rocky Mountains, which were eroded during the Permian age. Dipping beds are present in the western flank and flatten toward the east (Drake et al. 2014).

The Lower Cretaceous Muddy J-Sand and D-Sand, of the Dakota Group, are fine to medium grained siliciclastic sandstone. These formations were deposited during the Western Interior Seaway regression. The Skull Creek Shale below the Muddy J-Sand is the source rock for the reservoir. These two formations were the initial targets for oil and gas development beginning in the early 1970s (Drake et al. 2014).

During the Upper Cretaceous period, the Niobrara Formation and the Codell Sandstone Member of the Carlile Shale were deposited. The Codell Formation formed during a regression of the Western Interior Seaway. The Niobrara Formation was deposited during transgression of the Western Interior Seaway and is unconformable. It consists of interbedded chalk and marl units and is approximately 290 ft thick in the core of the Wattenberg Field (Drake et al. 2014). The Niobrara and Codell Formations were not exploited until the early 1980s due to their low permeability, even though logs indicated elevated hydrocarbon saturations. Hydraulic fracturing of these formations increases the effective permeability and allows these reservoirs to be commercially economic.

The Pierre Shale overlays the Niobrara Formation and was formed during the Upper Cretaceous period in deep sea environments. The Pierre Shale is considered impermeable and is a seal for the lower Niobrara and Codell Formations. The Shannon and Sussex Formations were deposited above the lower member of the Pierre Shale, at an average depth of 4,400 – 4,900 ft subsurface, during a regression of the Western Interior Seaway. These formations contain commercial quantities of hydrocarbons but are characteristically under-pressured (Sonnenberg and Weimer 2005). The transgression of the Western Interior Seaway allowed the continuation of the Pierre
Shale above the top of the Sussex Formation. The Pierre Shale is an important barrier separating the fresh water aquifers of the Wattenberg Field from hydrocarbon bearing formations below (Figure 4.2).

![Geologic stratigraphic units of the Denver-Julesburg Basin, Wattenberg Field, Colorado (Drake et al. 2014).](image)

4.2 Wattenberg Field Population Density

Weld County is located in the center of the Wattenberg Field. It is primarily a rural area with agriculture as its principal land use. The county has seven major cities: Brighton, Dacono, Evans, Fort Lupton, Greeley, Northglenn (part) and Thornton (part). Thornton, on the margin of oil and gas development, has the largest population in the county of 118,772 persons. Greeley has the second largest population of 92,889 persons. However, oil and gas development is limited within the city limits of Greeley. 95% of the wells in the Wattenberg Field sample set are located within the county. The
county is the third largest county in the state at 4,017 square miles and the 2013 population density is 63 persons per square mile (US Census 2013). The population in the county has grown by 199% since 1970 (Figure 4.3). This rise in population is an important consideration due to increased water sourcing from the fresh water aquifers within the field.

![Figure 4.3 Population of Weld County, Colorado from 1970 to 2013 (US Census 2013).](image)

Adams County is located on the southern edge of the Wattenberg Field. It has eight major cities near oil and gas development: Brighton, Commerce City, Federal Heights, Evans (part), Northglenn (part), Strasburg (part), Thornton (part) and Westminster (part). Oil and gas development in the county is primarily in rural areas surrounding Denver International Airport and north of Commerce City. Two percent of the wells in the Wattenberg Field sample set are located within Adams County. Adams county has seen significant population growth of 250% since 1970 (Figure 4.4). The county is 1,184 square-miles and the 2013 population density is 378 persons per square-mile (US Census 2013). However, this population density is skewed due to the
dense populations of the cities just north of the Denver metro area, which is considered outside the limits of the Wattenberg Field.

![Population of Adams County, Colorado from 1970 to 2013 (US Census 2013).](image)

Boulder County is located near the south-east edge of the Wattenberg Field. It has three major cities near oil and gas development: Lafayette, Longmont (part), and Louisville. The largest city in the county is Boulder, which contains 31% of the population. Boulder has no oil and gas development within the city limits. 28% of the county’s population resides in Longmont, which enacted a moratorium on hydraulic fracturing in 2012 which is against current state laws. As of September 2015, the localized ban on hydraulic fracturing will be advanced to the Colorado State Supreme Court (Antonacci 2015). Only two percent of the wells in the Wattenberg Field sample set are located within Boulder County. The county is 740 square-miles and has a 2013 population density of 391 persons per square-mile (US Census 2013). Boulder County has had a 231% increase in population since 1970 (Figure 4.5).

Larimer County is located on the north-west edge of the Wattenberg Field. It has two major cities near oil and gas development: Fort Collins and Loveland. Only 0.26%
of wells in the Wattenberg Field sample set are located within the county. Fort Collins also initiated a hydraulic fracturing moratorium in 2012, similar to the City of Longmont. 46% of the county’s population resides in Fort Collins. The county is 2,634 square-miles and has a 2013 population density of 115 persons per square-mile (US Census 2013). Larimer County has seen its population increase by 346% since 1970 (Figure 4.6).

![Figure 4.5 Population of Boulder County, Colorado from 1970 to 2013 (US Census 2013).](image)

![Figure 4.6 Population of Larimer County, Colorado from 1970 to 2013 (US Census 2013).](image)
4.3 Wattenberg Field Water Sourcing

The main fresh water aquifer system in the Wattenberg Field is the Denver Basin. This aquifer system is composed of the Dawson Arkose, Denver Formation, Arapahoe Formation, Laramie Formation and the Fox-Hills Sandstone (Figure 4.7). Below the base of the Fox-Hills Sandstone is the Pierre Shale, which is impermeable Cretaceous shale and acts as a barrier between deeper hydrocarbon deposits. The Denver Basin is recharged from the southerly surface by precipitation near the cross section B marker (Figure 4.7) (USGS 1995). The aquifer system underlying the Wattenberg Field contains localized coal seams, which naturally produce methane when water is removed from the coal surface and cleats.

Figure 4.7 Cross section of the Denver Basin aquifer system (USGS 1995).

The Fox-Hills Sandstone is the main fresh water aquifer underlying the Wattenberg Field in Colorado. The depth of this aquifer ranges from 100 ft subsurface in the north-east, to greater than 1,100 ft subsurface, moving south-west (Figure 4.8).
Early water sourcing in the 1970s was predominantly from local reservoirs and increased water well drilling didn’t occur until the 1980s in the Wattenberg Field after oil and gas development already commenced.

Figure 4.8 Fox-Hills aquifer depths in the Wattenberg Field correlated with water well depths and locations (ArcGIS 2016).

In 1993, the policy for Fox-Hills aquifer protection was established and stipulated that surface casing must be set 50 ft below the base of the Fox-Hills aquifer or 50 ft below the total depth of the deepest water well within a 0.5-mile radius of the oil and gas well. Rule 609 for baseline water well testing was implemented by the COGCC in 2009 which required that water wells within a 0.5-mile radius of a permitted oil and gas well be tested for water quality and any presence of hydrocarbons. The aquifer system in the Wattenberg Field has naturally occurring biogenic methane and methane from localized coal deposits within the Laramie Formation.
4.4 Wattenberg Field Data Sourcing and Assumptions

Oil and Gas well data from 17,948 wells was acquired from COGCC database that were drilled and completed from 1970 until February 2014. Potential barrier failures were identified by evidence of remedial cement below the surface casing shoe with the assumption that the oil and gas well experienced SAP as the reason for the cement remediation. Remedial cement on the production casing string was not identified as potential barrier failures in the Wattenberg Field due to the prevalence of hydraulically re-fracturing existing older wells. Operators would often perform cement remediation on these wells in order to further isolate target formations prior to re-fracturing operations and not due to a potential barrier failure or observance of SAP.

Catastrophic barrier failures were identified by thermogenic gas detected in offset water wells and evidence of a well barrier failure(s) in an off-set oil and gas well which contributed to thermogenic gas migration to a fresh water aquifer. The deepest fresh water aquifer, the Fox-Hills, base depths were obtained from ArcGIS online. Shallow surface casing was defined as being set above the base of the Fox-Hills aquifer or any instance of an off-set water well that is deeper than the Fox-Hills base depth within a 0.5 mile radius of an oil and gas well.

The TOC of production cement was supplied by the individual well scout cards in the COGCC database. If the depth of the cement top was not supplied, the quantity of cement was used to calculate the estimated top of cement based on a uniform wellbore geometry and typical yields for class H cement, 1.18 \( \text{ft}^3/\text{sack of cement} \). Tubing and packers are neglected in this study as an additional barrier.

In addition, if the Sussex Formation top was not supplied within an individual well scout card, then the average depth of the Sussex Formation was used and adjusted based on the topographic surface elevation of a well to estimate the top of the Sussex Formation. This formation is assumed to be the top of gas in the Wattenberg Field.

4.5 Wattenberg Field Historical Wellbore Designs

The Wattenberg Field is located near Denver, Colorado. Increased oil and gas development commenced in 1970, initially targeting the J-Sand Formation, which underlies the Niobrara and Codell Formations. The well designs in the 1970s set
shallow 8-5/8 inch surface casing that was cemented to surface and 4-1/2 inch production casing set to total depth and cemented above any “known” hydrocarbon bearing formations. State regulations during that era required surface casing to be set at a minimum depth of 200 ft or 5% of the total measured depth of the well. Many older wells had surface casing set above the base of the Fox-Hills aquifer. As populations have increased in the Wattenberg Field, the Fox-Hills aquifer became an important fresh water source for agriculture, commercial, municipal and domestic purposes. Current COGCC regulations for surface casing setting depths are designed to be set 50 ft below the base of the Fox-Hills aquifer or 50 ft deeper than the deepest water well within a 0.5-mile radius. Many current cement remediation jobs below the surface casing shoe are due to this new regulation.

Beginning in 1993, the COGCC strengthened regulations and designs were revised in order to further protect aquifers from hydrocarbon migration. Surface casing was set below the base of the Fox-Hills aquifer and production casing TOC was regulated to 200 ft above any known hydrocarbon zone. Many current well designs have production casing cement overlap into the surface casing in order to add additional barriers and create a nested barrier system. In 2010, horizontal wells, targeting the Niobrara or Codell Formations, were introduced in the Wattenberg Field. These newer horizontal wellbore barrier designs, as well as recent vertical wellbore designs, have a lower risk of hydrocarbon or fracturing fluid migration to fresh water aquifers due to their redundant barrier designs.

Wellbore barrier designs in the Wattenberg Field have transformed due to experience in the industry, enhanced equipment, technological improvements and recent COGCC regulations. Shallow surface casing depths were designed and implemented in the 1970s for the purpose of well control during drilling operations and not necessarily for fresh water aquifer protection (Figure 4.9). Due to the shallow depths of the surface casing in the 1970s, many cement remediation jobs were performed below the surface casing shoe, at a later time, in order to further protect the Fox-Hills aquifer. Beginning in 1994, surface casing was set deeper to further ensure barrier protection of the Fox-Hills aquifer (Figure 4.10).
Figure 4.9  Chronologic original surface casing setting depths in the Wattenberg Field.
Figure 4.10  Chronologic surface casing setting depths after cement remediation in the Wattenberg Field.
COGCC rule 317A states that surface casing shall be set at a minimum of 200 ft or 50 ft below the base depths of the Fox-Hills aquifer in the D-J Fox-Hills protection zone. The production casing TOC was designed to cover “known” hydrocarbon bearing formations in the 1970s. The Niobrara and Codell Formations, at an average depth of 6,950 – 7,400 ft true vertical depth (TVD), were thought to be unproductive until their discovery in the early 1980s. Because these over-pressured formations had low permeability, often the design of the production cement top was below the top of the Niobrara Formation.

The common design in the 1980s – mid 1990s had the TOC of the production cement below the top of the Sussex Formation. The Sussex Formation is characteristically under-pressured, defined as pressure less than the hydrostatic pressure of fresh water (Sonnenberg and Weimer 2005; Weimer et al. 1986). The annular fluid hydrostatic pressure from the original drilling mud and formation salt water often prevents hydrocarbon migration in the event that zonal isolation is not achieved from production cement (Figure 4.11). However, the pressure of the Sussex formation is not uniform across the field and could exhibit locality of normal to over-pressured environments.

![Figure 4.11 Pressure profile of formations in the Wattenberg Field, which displays the under-pressured nature of the Sussex Formation (Sonnenberg and Weimer 2005).](image)
Since the late 1990s, production cement tops were designed to cover shallow hydrocarbon bearing zones from the Sussex and Shannon Formations at depths of 4,400 – 4,900 ft (Figure 4.12). COGCC rule 317i states that production cement must be 200 ft above the top of any known producing horizon. Since then, many wells have had remedial cementing operations to address these older designs and to further ensure zonal isolation of all hydrocarbon bearing formations (Figure 4.13). In addition, many wells in the Wattenberg Field are hydraulically re-fractured in order to further stimulate existing producing formations or target new formations. Many wells must comply with current cement regulations prior to any re-fracturing treatment. Many wells had cement remediation performed on the production casing due to subsequent hydraulic re-fracturing work and not necessarily due to a potential barrier failure.

Figure 4.12  Chronologic origina top of production cement depths in the Wattenberg Field.
4.6 Wattenberg Field Wellbore Barrier Categories

The oil and gas wells in the Wattenberg Field have diverse designs depending on the age, target formations and bottom-hole trajectory. Wells are designed from the total anticipated depth to surface, utilizing various sizes of casing and different volumes of cement to isolate fluid transport between different formations. Seven common dual string barrier designs exist in the field (Table 4.1). Each has different risk levels depending on the number and type of barriers preventing hydrocarbon or fracturing fluid migration to fresh water aquifers from hydrocarbon bearing formations below the upper Pierre Shale.

Higher risk wellbore barrier designs include categories 1 and 2. Both categories have shallow surface casing in relation to the base depth of the Fox-Hills aquifer and
rely on the annular hydrostatic pressure as the only barrier between the Fox-Hills aquifer and an annular hydrocarbon migration flow path from deeper formations.

Category 1 wellbore barrier designs have the TOC of production cement below the top of the over-pressured Niobrara Formation (Figure 4.14). These wells only have a single annular hydrostatic pressure barrier. There were 166 wells that originally had this wellbore barrier design and they were predominantly drilled in the early 1970s when deeper Muddy J-Sand and D-Sand wells were completed. The Niobrara was thought to be uncommercial due to low permeability of the formation. The most probable hydrocarbon migration flow path is in the production casing annulus for this design.

Table 4.1 Original well counts by wellbore barrier category in the Wattenberg Field

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>VERTICAL OR DEVIATED ORIGINAL WELL COUNT</th>
<th>HORIZONTAL ORIGINAL WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>166</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>621</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>46</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>7</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>8,789</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>5,433</td>
<td>269</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>1,766</td>
<td>704</td>
</tr>
<tr>
<td>TOTAL</td>
<td>16,828</td>
<td>973</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>DRILLED AND ABANDONED WELL COUNT</th>
<th>VERTICAL OR DEVIATED ORIGINAL WELL COUNT</th>
<th>HORIZONTAL ORIGINAL WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>147</td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

TOTAL WELL COUNT 17,948

Category 2 well barrier designs have the TOC of production cement below the top of the under-pressured Sussex Formation, which is designated as the top of gas in the Wattenberg Field (Figure 4.15). These wells only have a single annular hydrostatic pressure barrier. 621 wells originally had this design and they were primarily drilled in the early 1980s. The most probable hydrocarbon migration flow path is in the production casing annulus. However, due to the under-pressured nature of the Sussex Formation,
the annular fluid hydrostatic pressure is often a sufficient barrier preventing hydrocarbon migration from the Sussex Formation to the Fox-Hills aquifer.

Figure 4.14  Wellbore diagram of a category 1 wellbore barrier design in the Wattenberg Field.
Figure 4.15  Wellbore diagram of a category 2 wellbore barrier design in the Wattenberg Field.
Moderate risk well barrier designs include categories 3 and 4. Both wellbore barrier categories have shallow surface casing set above the base of the Fox-Hills aquifer. Category 3 well barrier designs have the TOC of production cement above the top of the Sussex Formation (Figure 4.16). This design has two barriers: production casing and annular hydrostatic pressure. Only 46 wells originally had this design in the field and were primarily drilled in the late 1980s. The most probable hydrocarbon migration flow path is in the production casing.

Figure 4.16 Wellbore diagram of a category 3 wellbore barrier design in the Wattenberg Field.
Category 4 well barrier designs extend the TOC of production cement into the surface casing shoe (Figure 4.17). This design has two barriers: production casing and production cement. Only seven wells had this original design, which were drilled in the early 1980s. The most probable hydrocarbon migration flow path is in the production casing.

Figure 4.17 Wellbore diagram of a category 4 wellbore barrier design in the Wattenberg Field.
Lower risk well barrier designs include categories 5, 6 and 7. All of these wellbore barrier categories have deep surface casing set below the base of the Fox-Hills aquifer. Category 5 wells have the TOC of production cement set below the top of the Sussex Formation (Figure 4.18). This wellbore barrier design has three barriers: annular hydrostatic pressure, surface casing and surface cement. The most probable hydrocarbon migration flow path is in the production casing annulus. 8,789 wells originally had this design and it represents the most common vertical or deviated original wellbore barrier design in the Wattenberg Field. The most probable migration flow path is in the production casing annulus.

![Figure 4.18 Wellbore diagram of a category 5 wellbore barrier design in the Wattenberg Field.](image-url)
Category 6 well barrier designs have the TOC of production cement above the top of the Sussex Formation. Category 6 wells have three barriers: production casing, surface casing and surface cement (Figure 4.19). This wellbore barrier design is the second most common original well design in the Wattenberg Field, occurring on 5,433 vertical or deviated wells and 269 horizontal wells. The category 6 vertical or deviated wells had an average completion date of 2007 and the horizontal wells were completed in 2012. The most probable hydrocarbon migration flow path is in the production casing.

Figure 4.19 Wellbore diagram of a category 6 wellbore barrier design in the Wattenberg Field.
Category 7 well barrier designs have the least relative risk associated with their designs because the TOC of production cement is above the surface casing shoe (Figure 4.20). These wells have four barriers: production casing, production cement, surface casing and surface cement. 1,766 vertical or deviated wells and 704 horizontal wells originally had this design in the Wattenberg Field. The category 7 vertical or deviated wells had an average completion date of 2009 and the horizontal wells were completed in 2012. The most probable hydrocarbon migration flow path is in the production casing.

Figure 4.20 Wellbore diagram of a category 7 wellbore barrier design in the Wattenberg Field.
Of the 17,948 wells analyzed, 15,723 vertical or deviated wells are currently producing or shut-in in the Wattenberg Field and 1,105 vertical or deviated wells have been plugged and abandoned. In addition, 973 horizontal wells were analyzed; three of which were plugged and abandoned and the remaining horizontal wells are currently producing or shut-in. 147 vertical or deviated wells in the sample were drilled and abandoned (DA), without installing production casing. All drilled wells that were eventually completed were categorized based on their wellbore construction and number and types of barriers that protect groundwater from hydrocarbon or fracturing fluid migration.

Higher risk well barrier designs were prevalent from 1970 – 1994 (Figure 4.21). After strengthening the regulations of surface casing setting depths by the COGCC, lower risk barrier designs replaced the higher risk designs that had shallow surface casing in relation to the base depths of the Fox-Hills aquifer.

![Figure 4.21 Histogram of originally completed wells that are color coded by their original wellbore barrier design in the Wattenberg Field.](image)
Higher risk category 1 and 2 wells are primarily located in the southern area of the field where the base of the Fox-Hills aquifer is structurally deeper (Figure 4.22). 721 wells, or four percent of the data sample set, were originally drilled and completed in the Wattenberg Field as category 1 or 2 designations. Although these wells met the state regulations at the time of their completion, they all had surface casing set above the base of the Fox-Hills aquifer and inadequate production cement tops.

![Figure 4.22 Map of originally completed wells that are color coded by their wellbore barrier category in the Wattenberg Field.](image)

### 4.7 Wattenberg Field Potential Barrier Failures

Potential barrier failures were identified by remedial cement operations performed below the shoe of the surface casing, to further protect the fresh water aquifer in the Wattenberg Field. 418 vertical or deviated wells, or 2.48% of the original wells, were identified that had potential barrier failures that required cement remediation below the surface casing shoe (Table 4.2). Higher risk categories 1, 2 and 3 well barrier designs had the highest potential barrier failure rates of 60.24%, 35.27%, and 34.78%, respectively.
respectively. The shallow surface casing, coupled with the age of the wells, all led to 
SAP and subsequent cement remediation. However, no potential barrier failures were 
associated with evidence of thermogenic gas migration to the Fox-Hills aquifer based on 
base-line water testing on adjacent water wells within a 0.5-mile radius of the existing oil 
and gas well. Lower risk wellbore barrier categories 5 – 6, had very low potential barrier 
failure rates due to the increased number and strength of passive, static barriers 
present in the wells. No category 7 vertical well nor any horizontal wells were identified 
as having a potential barrier failures due to their more robust wellbore barrier designs 
and recent average completion dates (Table 4.2; Table 4.3).

Table 4.2 Potential barrier failures of vertical and deviated wells in the Wattenberg Field

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ORIGINAL WELL COUNT</th>
<th>POTENTIAL BARRIER FAILURES</th>
<th>ORIGINAL AVE AGE OF WELL</th>
<th>P&amp;A WELL COUNT</th>
<th>CURRENT WELL COUNT</th>
<th>ORIGINAL AVG SURFACE CASING DEPTH (FT)</th>
<th>ORIGINAL AVG TOP OF PRODUCTION CEMENT (FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>166</td>
<td>100</td>
<td>60.24%</td>
<td>1979</td>
<td>57</td>
<td>15</td>
<td>253</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>621</td>
<td>219</td>
<td>35.27%</td>
<td>1983</td>
<td>138</td>
<td>301</td>
<td>306</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>46</td>
<td>16</td>
<td>34.78%</td>
<td>1987</td>
<td>14</td>
<td>31</td>
<td>321</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>7</td>
<td>0</td>
<td>0.00%</td>
<td>1982</td>
<td>1</td>
<td>15</td>
<td>222</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>8,789</td>
<td>77</td>
<td>0.88%</td>
<td>1995</td>
<td>782</td>
<td>6,140</td>
<td>559</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>5,433</td>
<td>6</td>
<td>0.11%</td>
<td>2007</td>
<td>105</td>
<td>7,181</td>
<td>712</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>1,766</td>
<td>0</td>
<td>0.00%</td>
<td>2009</td>
<td>8</td>
<td>2,040</td>
<td>719</td>
</tr>
<tr>
<td>TOTAL</td>
<td>16,828</td>
<td>418</td>
<td>2.48%</td>
<td></td>
<td>1,105</td>
<td>15,723</td>
<td></td>
</tr>
<tr>
<td>D&amp;A</td>
<td>147</td>
<td>147</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.3 Potential barrier failures of horizontal wells in the Wattenberg Field

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ORIGINAL WELL COUNT</th>
<th>POTENTIAL BARRIER FAILURES</th>
<th>ORIGINAL AVE AGE OF WELL</th>
<th>P&amp;A WELL COUNT</th>
<th>CURRENT WELL COUNT</th>
<th>ORIGINAL AVG SURFACE CASING DEPTH (FT)</th>
<th>ORIGINAL AVG TOP OF PRODUCTION CEMENT (FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td>NA</td>
<td>0</td>
<td>0</td>
<td>NA</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td>NA</td>
<td>0</td>
<td>0</td>
<td>NA</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td>NA</td>
<td>0</td>
<td>0</td>
<td>NA</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td>NA</td>
<td>0</td>
<td>0</td>
<td>NA</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td>NA</td>
<td>0</td>
<td>0</td>
<td>NA</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>269</td>
<td>0</td>
<td>0.00%</td>
<td>2012</td>
<td>1</td>
<td>268</td>
<td>789</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>704</td>
<td>0</td>
<td>0.00%</td>
<td>2012</td>
<td>2</td>
<td>702</td>
<td>929</td>
</tr>
<tr>
<td>TOTAL</td>
<td>973</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td>3</td>
<td>970</td>
<td></td>
</tr>
</tbody>
</table>
Higher risk wellbore barrier designs exhibited the highest potential failure rates. 319 original category 1 and 2 wells received cement remediation below the surface casing shoe. Corrosion is not a common cause for production casing failure in the field due to the quality of the produced water which has lower TDS and lower salinity compositions than many unconventional gas fields in the U.S. (Li 2013). However, corrosive gas in the production stream from the Niobrara and Codell Formations has 1.0 - 3.4 mole percent of CO₂ (Higley and Cox 2007; Weimer et al. 1986). Corrosion can contribute to production casing failure, but the lower salinity of the produced water, which has fewer cations and anions than high salinity water, generally offsets the potential for high corrosion rates of the carbon-steel pipe. However, leaks can occur at casing connections due to thread galling during instillation of the production casing or increased loading conditions experienced due to thermal and stress alterations throughout the life cycle of the well.

Eighty percent of the potential barrier failures occurred on wells with shallow surface casing set above the base of the Fox-Hills aquifer. The age of the wells is also an important consideration, with the majority of the potential barrier failures occurring on legacy vertical and deviated wells from the 1970s and 1980s (Figure 4.23). Potential barrier failures were common where the base depth of the aquifer was greater than 300 ft subsurface located on the southern area of the field (Figure 4.24).

![Histogram of potential barrier failures color coded by the well's original wellbore barrier design in the Wattenberg Field.](image)
4.8 Wattenberg Field Catastrophic Barrier Failure Overview

Catastrophic barrier failure is the breakdown of the combination of various wellbore barriers (casing, cement and hydrostatic pressure of annular fluids) protecting fresh water aquifers during stimulation and production operations resulting in the contamination of the aquifers. Contamination can be characterized by comparing the surrounding water well chemistry to the produced fluids of adjacent oil and gas wells through analytic and isotopic analysis. All wells in the field that were eventually turned to production were artificially stimulated with some form of hydraulic fracturing technology. Typical hydraulic fracturing treatment designs in the field utilize 98% fresh water, KCl and various friction reducers, bacteria inhibitors and small volumes of HCl acid, in addition to silica sand proppant. No evidence was found in this study that hydraulic fracturing operations directly contaminated fresh water aquifers in the Wattenberg Field (ArcGIS 2016).
Wattenberg Field. All catastrophic barrier failures were related to hydrocarbon migration through the wellbore to the fresh water aquifer or surface.

Ten of 16,828 originally producing vertical or deviated wells were identified that had a catastrophic barrier failure, representing a 0.06% catastrophic barrier failure rate (Table 4.4). The most common failure characteristic is shallow surface casing and inadequate production cement design on older wells in the Wattenberg Field. No lower risk category 6 or 7 wells experienced a catastrophic barrier failure due to their redundant nested barrier designs. In addition, no horizontal wells were identified as having a catastrophic barrier failure.

<table>
<thead>
<tr>
<th>VERTICAL WELLS</th>
<th>ORIGINAL WELL COUNT</th>
<th>CATASTROPHIC BARRIER FAILURES</th>
<th>CATASTROPHIC BARRIER FAILURE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>166</td>
<td>3</td>
<td>1.81%</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>621</td>
<td>5</td>
<td>0.81%</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>46</td>
<td>1</td>
<td>2.17%</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>7</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>8,789</td>
<td>1</td>
<td>0.01%</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>5,433</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>1,766</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>16,828</td>
<td>10</td>
<td>0.06%</td>
</tr>
</tbody>
</table>

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Catastrophic barrier failures were identified in three category 1 wells, five category 2 wells, one category 3 well, and one category 5 wells (Figure 4.25). Nine wells had commonality of shallow surface casing set above the base of the Fox-Hills aquifer. One category 5 catastrophic barrier failure had deep surface casing but had no evidence of fresh water aquifer contamination. This well had elevated benzene levels at surface near the well, which could be due to surface leaks in the flowlines or production tanks. Nonetheless, this well was determined to be a catastrophic barrier failure in the analysis. The remaining catastrophic barrier failures either have improper cement isolation in the production casing annulus or leaks in the production casing at shallow
depths that were potentially caused by corrosion or leaks at the casing collars that resulted in a direct migration pathway to the fresh water aquifer in the annulus. Violations were issued by the COGCC to current operators for violating rule 324A for the unauthorized discharge of gas from an oil and gas well that impacted the water quality of a water well.

Catastrophic barrier failures were common in high risk well barrier categories. Categories 1 and 2 had only a single hydrostatic pressure barrier in the annulus preventing hydrocarbon migration. Category 1 wells have the highest risk of barrier failure due to shallow surface casing and non-cement isolation of the over-pressured Niobrara Formation. This barrier design had a 60.24% potential barrier failure rate and a 1.81% catastrophic barrier failure rate. Category 2 barrier designs have a 35.27% potential barrier failure rate and a 0.64% catastrophic barrier failure rate. Category 3 barrier designs have a 34.78% potential barrier failure rate and a 2.17% catastrophic
barrier failure rate. Category 5 wellbore barrier designs, the most common original vertical or deviated well design in the Wattenberg Field, have a 0.88% potential barrier failure rate and a 0.02% catastrophic barrier failure rate. Remaining vertical or deviated wellbore barrier categories had no evidence of catastrophic barrier failures.

Horizontal wells began in 2010 and represent more recent nested barrier designs with a lower risk of catastrophic barrier failure. No horizontal wells have shallow surface casing in the data set. 269 category 6 horizontal wells and 704 category 7 horizontal wells were originally completed in the field. Due to the infancy of these wells and the redundant nested barrier designs, no failures have been identified from the horizontal wells in the data set.

Li and Carlson performed a study in 2014 to identify the presence and origin of biogenic and thermogenic gas in the Fox-Hills aquifer. 176 water wells were sampled across the Wattenberg Field. The study found 70.5% of water wells sampled had methane concentrations < 5 mg/L and 1.2% of water wells sampled had methane concentrations > 25 mg/L. However, only two samples detected thermogenic gas in the study which matches this study’s findings of two catastrophic barrier failures (Figure 4.26) (Li and Carlson 2014). All remaining methane samples from the water wells were biogenic, originating naturally in the aquifer. This demonstrates the prevalence of naturally occurring biogenic methane in the Denver Basin aquifer system.

Figure 4.26 Study performed by Li and Carlson in 2014 that displays locations of water wells that tested positive for the presence of biogenic or thermogenic gas in the Wattenberg Field (Li and Carlson 2014).
A similar study was performed by Strauss et al. in 2014 that detected 12 of 93 water wells that tested positive for methane concentrations greater than one mg/L that were thermogenic in origin from the J-Sand, Codell, Niobrara or Sussex Formations (Figure 4.27). Nonetheless, 81 of the remaining water wells that tested positive for methane were bacterial (biogenic) in nature and originated from methanogens within the aquifer system. The locations of the thermogenic gas presence in the aquifers match this study’s findings for the oil and gas well catastrophic barrier failures. Both of these studies demonstrate the common presence of biogenic methane in the aquifer system.

Figure 4.27 Study performed by Strauss et al. in 2014 that displays locations of water wells that tested positive for bacterial or thermogenic gas in the Wattenberg Field (Strauss et al. 2014).

4.9 Wattenberg Field Catastrophic Barrier Failures

05-001-07626 was drilled in 1980 with a category 1 well barrier design. This well had shallow surface casing set at 212 ft and TOC of production cement at 7,036 ft, below the top of Niobrara Formation. An off-set water well, 323 ft radial distance from the oil and gas well, was drilled in 2003 to a depth of 400 ft, below the depth of the oil and gas well’s surface casing shoe. In 2006, thermogenic gas was detected in the water well, coupled with evidence of high SAP in well 05-001-07626. After MIT inspection, it was determined that the oil and gas well had holes in the production casing at shallow depths. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well
violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-001-07626 was remediated and is currently a category 5 well.

05-123-07854 was drilled in 1974 with a category 1 well barrier design. This well had shallow surface casing set at 222 ft and TOC of production cement of 7,000 ft. In 2004, thermogenic gas was detected in offset water well that was 161 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. The oil and gas well passed an MIT test of the production casing. The hydrocarbon flow path was determined to be in the annulus of the oil and gas well due to inadequate cement coverage and ultimate barrier failure of the annular hydrostatic pressure. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-07854 was remediated and is currently a category 5 well.

05-123-08926 was drilled in 1976 with a category 1 well barrier design. This well had shallow surface casing set at 212 ft and TOC of production cement of 7,090 ft. In 2012, thermogenic gas was detected in offset water well that was 968 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. This area was also detected by Li and Carlson in 2014 for the presence of thermogenic gas. The oil and gas well passed an MIT test of the production casing and the hydrocarbon flow path was determined to be in the production casing annulus due to inadequate cement coverage of high pressured hydrocarbon bearing zones and subsequent annular hydrostatic barrier failure. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-08926 was remediated and is currently a category 5 well.

05-123-11848 was drilled in 1984 with a category 2 well barrier design. This well had shallow surface casing set at 337 ft and TOC of production cement of 6,185 ft. In 2009, an offset water well was drilled to a depth of 450 ft below ground level that was 960 ft radial distance from the oil and gas well and immediately detected the presence of thermogenic gas. SAP was observed on oil and gas well during the same time period. The oil and gas well failed an MIT test of the production casing due to holes or
leaks in the production casing at shallow depths. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-11848 was plugged and abandoned in 2009.

05-123-08385 was drilled in 1975 with a category 2 well barrier design. This well had shallow surface casing set at 690 ft and TOC of production cement of 6,440 ft. In 2002, thermogenic gas was detected in offset water well that was 5,160 ft radial distance from the oil and gas well and high SAP was observed on oil and gas well. A seal leak in the wellhead was detected which allowed the flow path to extend from inside the production casing to the annulus in the oil and gas well. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-08385 was remediated in 2002 and is currently a category 6 well.

05-001-06164 was drilled in 1970 with a category 2 well barrier design. This well had shallow surface casing set at 136 ft and TOC of production cement of 7,420 ft. In 2001, thermogenic gas was detected in an offset water well that was 1,610 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. The oil and gas well failed a MIT test of the production casing due to holes or leaks in the production casing at shallow depths. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-001-06164 was remediated in 2001 and later plugged and abandoned in 2012.

05-001-08161 was drilled in 1974 with a category 2 well barrier design. This well had shallow surface casing set at 640 ft and TOC of production cement of 7,000 ft. In 2010, thermogenic gas was detected in an offset water well that was 1,600 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. This area was also detected by Li and Carlson in 2014 for the presence of thermogenic gas. The oil and gas well failed a MIT test of the production casing due to holes or leaks in the production casing at shallow depths. Isotopic gas analysis of the annular
gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-001-08161 was remediated in 2010 and later plugged and abandoned in 2012.

05-123-12383 was drilled in 1985 with a category 2 well barrier design. This well had shallow surface casing set at 302 ft and TOC of production cement of 6,100 ft. In 2004, thermogenic gas was detected in an offset water well that was drilled into the unconsolidated Pierre shale at a depth of 675 ft. The water well was 320 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. This oil and gas well is located north in the Wattenberg Field where the Fox-Hills aquifer pinches out. The oil and gas well failed a MIT test due to holes or leaks in the production casing detected at 761 – 1,250 ft subsurface. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-12383 was remediated in 2004 and later plugged and abandoned in 2014.

05-123-16027 was drilled in 1992 with a category 3 well barrier design. This well had shallow surface casing set at 761 ft and TOC of production cement of 4,010 ft. In 2006, thermogenic gas was detected in an offset water well that was 320 ft radial distance from the oil and gas well and high SAP was observed on the oil and gas well. The oil and gas well failed a MIT test on the production casing due to holes or leaks in the production casing at shallow depths. Isotopic gas analysis of the annular gas and the gas sample from the water well matched and the COGCC determined that the oil and gas well violated rule 324A for contamination of fresh water aquifers related to hydrocarbon migration. 05-123-16027 was remediated in 2006 and is currently a category 6 well.

05-013-06096 was drilled in 1982 with a category 5 well barrier design. It had deep surface casing set at 200 ft and TOC of production cement of 6,190 ft. In 2006, benzene was detected in the soil samples surrounding the well and no documented SAP was observed on the oil and gas well. It is unclear if this wellbore had direct causation of elevated benzene levels in the surrounding soil or if the benzene came
from an alternate source, like a leak in a production tank or surface flowline. It was classified as a catastrophic barrier failure in this analysis. The operator was ordered to alleviate the elevated benzene levels on the pad. This well was later recompleted in 2010 to produce from the Codell Formation.

Ten of 17,801 of the originally producing oil and gas wells experienced a catastrophic barrier failure related to hydrocarbon migration to fresh water aquifers or surface soil in the Wattenberg Field. This small percentage of catastrophic barrier failures, 0.06%, proves the low risk of aquifer contamination but conversely, displays that there is a possibility of contamination related to hydrocarbon migration in the Wattenberg Field if wellbores are designed poorly. Due to a defined geologic barrier, the Pierre Shale, below the base of the aquifer system, water wells are protected from natural hydrocarbon migration as long as they are drilled to depths less than the base depth of the Fox-Hills Sandstone. Higher risk wellbore barrier designs more commonly fail due to the lack of redundant barriers and their older age.

However, no evidence of fracturing fluid migration was detected in the dataset, even in wells that had higher risk wellbore barrier designs. This also establishes that adding pressure monitoring equipment to the fracturing fluid string and casing annulus during hydraulic fracturing operations reduces the overall risk of aquifer contamination. In addition, the geologic barrier of the Pierre Shale, validates that fracture height growth is limited to within the targeted formations and doesn’t extend thousands of feet to surface aquifers.

4.10 Wattenberg Field Existing Conditions

There are 15,723 of the original 16,828 vertical or deviated wells currently producing or shut-in in the Wattenberg Field (Table 4.5). Of which, 15,361 wells currently have deep surface casing and 362 wells have shallow surface casing in relation to the base depth of the Fox-Hills aquifer. There are 970 of the original 973 horizontal wells in the field presently producing or shut-in (Table 4.6). All horizontal wells have deep surface casing and lower risk category 6 and 7 wellbore barrier designs. Figure 4.28 displays all currently producing vertical and deviated wells with their current wellbore category designations.
Of the 362 wells that have been defined as having shallow surface casing in relation to the depths of the Fox-Hills aquifer, the majority are located in the southern area of the Wattenberg Field where the Fox-Hills base depths are structurally lower (Figure 4.29). 89% of the wells that currently have shallow surface casing were completed prior to 1995 when surface casing regulations were less robust than current regulations.

Table 4.5 Current vertical and deviated well counts for wellbore barrier categories in the Wattenberg Field

<table>
<thead>
<tr>
<th>VERTICAL WELLS</th>
<th>CURRENT WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>15</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>301</td>
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<tr>
<td>CATEGORY 3</td>
<td>31</td>
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<tr>
<td>CATEGORY 4</td>
<td>15</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>6,140</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>7,181</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>2,040</td>
</tr>
<tr>
<td>TOTAL</td>
<td>15,723</td>
</tr>
</tbody>
</table>

Table 4.6 Current horizontal well counts for wellbore barrier categories in the Wattenberg Field

<table>
<thead>
<tr>
<th>HORIZONTAL WELLS</th>
<th>CURRENT WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>268</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>702</td>
</tr>
<tr>
<td>TOTAL</td>
<td>970</td>
</tr>
</tbody>
</table>
Figure 4.28  Map of existing producing or shut-in vertical or deviated wells color coded by their current wellbore barrier category in the Wattenberg Field.
Figure 4.29 Map of existing vertical or deviated wells with surface casing set below the base of the Fox-Hills aquifer in the Wattenberg Field (ArcGIS 2016).
All 970 currently producing or shut-in horizontal wells have deep surface casing in relation to the base depth of the Fox-Hills aquifer (Figure 4.30). The horizontal wells often are designed with deep surface casing, an intermediate casing string at the landing point of the curve in the target formation, which is cemented either above the top of the Sussex Formation or cemented into the surface casing shoe, and an un-cemented production liner that extends from the shoe of the intermediate casing to total depth. Under this tapered casing string design, the intermediate casing is considered part of the production casing. Horizontal wells are the current standard in the Wattenberg Field and their lower risk barrier designs represent improvements in regulations and engineering advances based on previous wellbore designs in the field since 1970.

Figure 4.30  Map of existing horizontal wells with the locations and depths of water wells in the Wattenberg Field.
The Piceance Basin in Garfield County, Colorado, began exploratory drilling operations in 1935. The basin is located in the western half of Colorado and extends into the Unita Basin in Utah (Figure 5.1). Concentrated oil and gas exploration of the field didn’t begin until 2000. Wells are drilled to depths of 6,000 ft – 8,000 ft subsurface, targeting the Williams Fork Formation, Iles Formation, Mesaverde Group, and deeper Mancos Shale and Niobrara Formations. The majority of wells are deviated and drilled from single pads with multiple wells per pad. Horizontal wells began around 2008, but horizontal drilling activity is negligible compared to the vertical and deviated well counts due to the complexity of drilling a horizontal well at increased depths of 10,000 ft – 12,500 ft TVD, targeting either the Mancos Shale and Niobrara Formation. Wells in the Piceance Basin are subject to higher corrosion rates due to elevated TDS of the produced water and the presence of corrosive gas. In addition, cementing wells can be problematic due to fracturing in the Wasatch Group which is above the Williams Fork Formation target zone.

Figure 5.1 Geographic location of the Piceance Basin, Garfield County, Colorado.
The Piceance Basin encompasses Garfield, Rio Blanco, Mesa, Delta, Montrose, Moffat and Gunnison Counties. Garfield County comprises the core of oil and gas exploration for the Piceance Basin in Colorado and will be the focus for this study. The main oil and gas fields in Garfield County are Mamm Creek, Rulison, Parachute, and Grand Valley, which are all in close proximity to Interstate 70 between Grand Junction and Glenwood Springs.

5.1 Piceance Basin Geology

The Piceance Basin is a large sedimentary basin formed during the Late Cretaceous and Eocene geologic time periods (Johnson and Flores 2003). The principle producing reservoir in the Piceance Basin, Garfield County, Colorado is the Mesaverde Group, which includes the Williams Fork Formation and the Iles Formation. Structurally deeper formations include the Mancos Shale and Niobrara Formations, which are targets for exploratory horizontal drilling (Figure 5.2).

Figure 5.2 Geologic stratigraphic units of the Piceance Basin (Johnson and Flores 2003).
The source rocks in the basin are from coal and carbonaceous shale, which were deposited in mires, swamps and marshes. The most important coal zone is the Cameo-Wheeler Coal Group. Gas migration from these coals migrated upward to sandstone beds in the upper Mesaverde Group. These gas accumulations started the expansion of basin-centered gas in the Piceance Basin (Johnson and Flores 2003).

The Wasatch Group, above the Williams Fork Formation, is composed of interbedded shale and sandstone and is highly fractured due to the structural alterations and thermogenic gas migration from the underlying Williams Fork Formation (URS 2006). Operators designate the top of gas in the field above the Williams Fork Formation. However, trace gas shows are evident in the Wasatch Group, which extends from the top of the Williams Fork to the unconsolidated alluvial sediments which are around 60 ft subsurface near stream channels (URS 2006). The Wasatch Group is not a defined geologic barrier between deeper hydrocarbon deposits and shallower fresh water aquifers.

5.2 Piceance Basin Population Density

Garfield County contains seven major townships or cities: Glenwood Springs, Carbondale, Rifle, New Castle, Battlement Mesa, Silt and Parachute. Glenwood Springs is the largest city in Garfield County had is considered outside the limits of oil and gas development. Rifle has 17% of the county’s population and is the largest city in proximity to oil and gas development, which is located near the Mamm Creek Field. The county is 2,956 square-miles and has a 2013 population density of 19 persons per square-mile (US Census 2013). The population of Garfield County has seen significant growth of 282% since 1970 and has a 2013 population estimate of 57,302 persons. As populations have increased in the county, water sourcing has increased from surface, alluvial aquifers and deeper bedrock aquifers in the upper Wasatch Group.

5.3 Piceance Basin Water Sourcing

A defined geologic boundary between fresh water aquifers and deeper hydrocarbon formations, similar to the Denver Basin aquifer system in the Wattenberg Field, is not present in Garfield County. Water is sourced from surface water,
unconsolidated alluvial aquifers that are shallower than 60 ft subsurface and deeper water wells that source fresh water from bedrock in the Wasatch Group at maximum depths of 600 ft (Figure 5.3). A study performed by Papadopulos in 2011, found that the water quality of the aquifer system in the Mamm Creek Field, near the towns of Rifle and Silt, had high concentrations of TDS for 95% of the groundwater samples that were tested between 2005 and 2011 (Papadopulos 2011). In addition, the study concluded that the water quality in the field didn’t change in the six year period during high oil and gas development. Only six samples from water wells tested positive for the presence of methane above the one mg/L threshold. However, the study determined that the methane was present prior to any oil and gas drilling operations in the testing area.

Figure 5.3 Map of water well locations and depths in the Piceance Basin – Garfield County.

The Wasatch Group, which is primarily shale and sandstone, has evidence of natural fractures that can act as a conduit to shallower depths from deeper and more mature hydrocarbon deposits. The deepest water wells in Garfield County are drilled to
600 ft, sourcing water from the Wasatch Group. Ninety percent of the water wells in the Mamm Creek Field are drilled into this formation (URS 2006). Water wells that are drilled into the bedrock of the Wasatch Group have the potential of testing positive for thermogenic gas without any offset oil and gas wells contributing to the thermogenic gas migration to the aquifer. It is challenging to ascertain the origin of thermogenic gas that appears in water wells due to the complexity of the underlying strata in Garfield County.

5.4 Piceance Basin Data Sourcing and Assumptions

Oil and gas well data was collected from the COGCC facilities database for 10,998 wells completed between 1935 to mid-2014 in Garfield County. Shallow surface casing was defined as less than the deepest water well in the field at 600 ft due to the majority of the water wells in the COGCC database in the Piceance Basin lacking depths to correlate shallow or deep surface casing setting depths for off-set oil and gas wells. Therefore, shallow surface casing is defined as less than the deepest water well in the field at 600 ft. The top of production cement depth was supplied by the individual scout cards on the COGCC database and confirmed by cement bond logs. If a top of cement was unreported or appeared inaccurate, the quantity of cement, uniform wellbore geometry and a yield of 1.18 ft³/sack of cement were used to estimate the top of cement. Due to the very small sample set of horizontal wells in the field, all horizontal wells will be grouped with the vertical and deviated wells for categorization.

Potential barrier failures were defined as any cement remediation performed on the production casing, intermediate casing or surface casing or presence of SAP. Additional data was collected from a previous study performed by URS which identified 148 wells within the Mamm Creek Field that had high SAP that exceeded 150 psi between 2004 and 2005 (URS 2006). These wells were additionally designated potential barrier failures.

Catastrophic barrier failures were defined as wells that had barrier failures that directly caused a conduit for hydrocarbon migration to fresh water aquifers of the upper Wasatch Group or alluvial aquifers at shallow depths, which was corroborated by isotopic and compositional analysis from an offset water well. Violations were issued by
the COGCC to the operator of the well which violated rule 324A, for unlawful discharge of hydrocarbons to fresh water sources.

5.5 Piceance Basin Historical Wellbore Barrier Designs

All wells were categorized based on their original casing and cement designs in the Piceance Basin, Garfield County, Colorado. 156 wells were drilled and abandoned. There are ten common original wellbore barrier designs in the field with no category 1 or 10 wells present in the dataset (Table 5.1). Well designs in the Piceance Basin are different than the common Wattenberg Field designs and can include three string casing designs. This additional casing string, known as intermediate casing, which is set at deeper depths relative to the surface casing string, adds additional barriers to the overall nested barrier system. The highest risk well barrier designs in the field are category 2 wells. 6.4% of the oil and gas wells originally had shallow surface casing set below 600 ft subsurface and 93.6% of the wells had deep surface casing setting depths. The core area of development is between Rifle and Parachute, straddling Interstate 70 (Figure 5.4).

Table 5.1 Original well counts by wellbore barrier category in the Piceance Basin – Garfield County

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ORIGINAL WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>48</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>145</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>509</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>1,789</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>6,233</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>1,862</td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>60</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>90</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>105</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>1</td>
</tr>
<tr>
<td>TOTAL</td>
<td>10,842</td>
</tr>
</tbody>
</table>

| DRILLED AND ABANDONED WELL COUNT | 156 |
| TOTAL WELL COUNT | 10,998 |
Figure 5.4 Map of original wells color coded by their original wellbore barrier designs in the Piceance Basin – Garfield County.
Average surface casing setting depths have increased throughout the development of the Piceance Basin in Garfield County. Infill development began in 2000 and continued to 2013 (Figure 5.5). During this infill development, average surface casing depths increased to 1,600 – 1,800 ft subsurface (Figure 5.6). However, due to the new average deeper setting depths of the surface casing beginning in 2000, the average production casing cement top was lower subsurface than historical trends, 3,000 – 4,000 ft (Figure 5.7, see page 69). Many wells drilled prior to 2000 had production cement to surface with shallower surface casing. 57% of the new designs have deep surface casing and the top of production cement above the top of the Williams Fork Formation.

Figure 5.5 Histogram of originally completed wells color coded by their wellbore barrier category in the Piceance Basin – Garfield County.
Figure 5.6  Chronologic original surface casing setting depths in the Piceance Basin – Garfield County.
Figure 5.7 Chronologic original top of production cement depths in the Piceance Basin – Garfield County.

5.6 Piceance Basin Wellbore Barrier Categories

Higher risk category 2 wells have shallow surface casing set above 600 ft subsurface and the TOC of production cement below the top of the Williams Fork Formation, which is considered the top of gas for this study (Figure 5.8). 48 wells were originally completed with this design and were primarily completed around 1994. The most probable hydrocarbon flow path for this design is in the production casing annulus. These wells have only a single annular hydrostatic pressure barrier preventing hydrocarbon migration to fresh water aquifers.

Moderate risk wellbore barrier designs include categories 3 and 4. Each of these designs have shallow surface casing in relation to the deepest water well in the study area. Category 3 wells have the TOC production cement above the Williams Fork
Formation (Figure 5.9). However, trace gas shows are evident in the Wasatch Group above the Williams Fork Formation (URS 2006). The Wasatch Group is highly fractured and contains small quantities of thermogenic and biogenic gas near the surface. Many deeper water wells that penetrate the Wasatch Group can contain thermogenic gas without the presence of oil and gas wells in the vicinity of the deep water well. 145 wells were originally completed with this design and they have an average completion date of 1995. The most probable hydrocarbon migration flow path is in the production casing for this design. These wells have two barriers: production casing and annular hydrostatic pressure.

Figure 5.8 Wellbore diagram of a category 2 wellbore barrier design in the Piceance Basin – Garfield County.
Figure 5.9 Wellbore diagram of a category 3 wellbore barrier design in the Piceance Basin – Garfield County.
Category 4 well barrier designs have deep surface casing and the TOC of production cement above the surface casing shoe (Figure 5.10). 509 wells were originally completed with this design with an average completion date of 1989. The most probable hydrocarbon flow path for this design is also in the production casing. These wells have two barriers: production casing and production cement.

Figure 5.10  Wellbore diagram of a category 4 wellbore barrier design in the Piceance Basin – Garfield County.
Lower risk dual string well barrier designs include categories 5, 6 and 7. All of these well barrier designs have deep surface casing set below 600 ft subsurface. Category 5 well barrier designs have the TOC of production casing cement below the top of the Williams Fork Formation (Figure 5.11). 1,789 wells were originally completed as category 5 wells, which have an average completion date of 2007. This well design has three barriers: annular hydrostatic pressure, surface casing and surface cement. The most probable hydrocarbon migration flow path is in the production casing annulus for these designs.

Figure 5.11 Wellbore diagram of a category 5 wellbore barrier design in the Piceance Basin – Garfield County.
Category 6 wells have deep surface casing and the TOC of the production cement above the top of the Williams Fork Formation (Figure 5.12). This well barrier design is the most abundant original design in the field. 6,233 wells were originally completed as category 6 wells, which have an average completion date of 2008. The most probable hydrocarbon migration flow path is in the production casing. This design has three barriers: production casing, surface casing and surface cement.

Figure 5.12 Wellbore diagram of a category 6 wellbore barrier design in the Piceance Basin – Garfield County.
Category 7 well barrier designs have deep surface casing and the TOC of production cement above the surface casing shoe (Figure 5.13). 1,862 wells were originally completed as category 7 wells, which have an average completion date of 2004. The most probable hydrocarbon migration flow path is in the production casing. This design has four barriers: production casing, production cement, surface casing and surface cement.

Figure 5.13 Wellbore diagram of a category 7 wellbore barrier design in the Piceance Basin – Garfield County.
Lower risk barrier designs incorporate three string casing designs, which include categories 8 – 12. Category 8 well barrier designs have deep surface casing, intermediate casing that has the TOC of intermediate cement above the top of the Williams Fork Formation and a TOC of production casing cement below the top of the Williams Fork Formation (Figure 5.14). Sixty wells were originally completed as category 8 wells, which have an average completion date of 2007. The most probable hydrocarbon migration flow path is in the production casing annulus. This design has five barriers: hydrostatic pressure in the production casing annulus, intermediate casing, hydrostatic pressure in the intermediate casing annulus, surface casing and surface cement.

Figure 5.14 Wellbore diagram of a category 8 wellbore barrier design in the Piceance Basin – Garfield County.
Category 9 well barrier designs have shallow surface casing, an intermediate casing string with the TOC of intermediate cement above the top of the Williams Fork Formation and the TOC of production cement above the intermediate casing shoe (Figure 5.15). Ninety wells were originally completed as category 9 wells, which have an average completion date of 1984. The most probable hydrocarbon migration flow path is in the production casing. This design has four barriers: production casing, production cement, intermediate casing and intermediate cement.

Figure 5.15 Wellbore diagram of a category 9 wellbore barrier design in the Piceance Basin – Garfield County.
Category 11 wells have deep surface casing, an intermediate casing string with TOC of intermediate cement above the surface casing shoe and the TOC of production cement above the top of the intermediate casing shoe (Figure 5.16). 105 wells were originally completed with a category 11 design, which have an average completion date of 2004. The most probable hydrocarbon migration flow path is in the production casing. This design has six barriers: production casing, production cement, intermediate casing, intermediate cement, surface casing and surface cement.

Figure 5.16 Wellbore diagram of a category 11 wellbore barrier design in the Piceance Basin – Garfield County.
Only one well was drilled with a category 12 designation, which was subsequently plugged and abandoned (P&A). This well barrier design has deep surface casing, two intermediate casing strings with the TOC of intermediate cement above the previous casing shoe and the TOC of production cement above the previous intermediate casing shoe. No figure will be provided for category 12 well barrier designs due to its immaterial well count and subsequent plug and abandonment.

5.7 Piceance Basin Potential Barrier Failures

Potential barrier failures were identified by any cement remediation of any casing string or evidence of SAP. Potential barrier failures were identified in 377 of 10,842 originally producing wells in Garfield County (Table 5.2). Category 8 wells had the highest potential barrier failure rate of 30.00%, occurring on 18 of 60 wells. Even though this design has deep surface casing and an intermediate casing string, the top of the production cement was not above the top of gas. Higher risk category 2 wells had an 8.33% potential barrier failure rate, occurring on four of 48 wells followed by category 5 wells which had a 6.99% potential barrier failure rate, occurring on 125 of 1,789 wells. This design has deep surface casing but the top of the production cement was not above the top of gas.

Table 5.2 Potential barrier failures in the Piceance Basin – Garfield County

<table>
<thead>
<tr>
<th>PICEANCE GARFIELD COUNTY WELLS</th>
<th>ORIGINAL WELL COUNT</th>
<th>POTENTIAL BARRIER FAILURES</th>
<th>POTENTIAL BARRIER FAILURE %</th>
<th>ORIGINAL AVG AGE OF WELL</th>
<th>P&amp;A WELL COUNT</th>
<th>CURRENT WELL COUNT</th>
<th>ORIGINAL AVG SURFACE DEPTH (FT)</th>
<th>ORIGINAL AVG INT 1 DEPTH (FT)</th>
<th>ORIGINAL AVG INT 1 TOP OF CEMENT (FT)</th>
<th>ORIGINAL AVG TOP OF PRODUCTION CEMENT (FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 2</td>
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<td>4</td>
<td>8.33%</td>
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<td>10</td>
<td>35</td>
<td>341</td>
<td></td>
<td>4,425</td>
<td></td>
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<tr>
<td>CATEGORY 3</td>
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<td>10</td>
<td>6.90%</td>
<td>1995</td>
<td>35</td>
<td>108</td>
<td>333</td>
<td></td>
<td>2,671</td>
<td></td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>509</td>
<td>10</td>
<td>1.96%</td>
<td>1989</td>
<td>55</td>
<td>459</td>
<td>363</td>
<td></td>
<td>3</td>
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</tr>
<tr>
<td>CATEGORY 5</td>
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<td>125</td>
<td>6.99%</td>
<td>2007</td>
<td>50</td>
<td>1,664</td>
<td>1,504</td>
<td></td>
<td>4,799</td>
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<tr>
<td>CATEGORY 6</td>
<td>6,233</td>
<td>145</td>
<td>2.33%</td>
<td>2008</td>
<td>63</td>
<td>6,205</td>
<td>1483</td>
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<tr>
<td>CATEGORY 7</td>
<td>1,862</td>
<td>56</td>
<td>3.01%</td>
<td>2004</td>
<td>74</td>
<td>1,827</td>
<td>1807</td>
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<td>1,048</td>
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<tr>
<td>CATEGORY 8</td>
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<td>18</td>
<td>30.00%</td>
<td>2007</td>
<td>8</td>
<td>43</td>
<td>1929</td>
<td>6487</td>
<td>3159</td>
<td>7,323</td>
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<tr>
<td>CATEGORY 9</td>
<td>90</td>
<td>2</td>
<td>2.22%</td>
<td>1984</td>
<td>30</td>
<td>58</td>
<td>383</td>
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<td>0</td>
<td>0.00%</td>
<td></td>
<td>0</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 11</td>
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<td>7</td>
<td>6.67%</td>
<td>2004</td>
<td>9</td>
<td>106</td>
<td>1716</td>
<td>6767</td>
<td>2463</td>
<td>4,721</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>1</td>
<td>0</td>
<td>0.00%</td>
<td>1992</td>
<td>1</td>
<td>981</td>
<td>7293</td>
<td>0</td>
<td>13,507</td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>10,842</td>
<td>377</td>
<td>3.48%</td>
<td></td>
<td>335</td>
<td>10,507</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D&amp;A</td>
<td>156</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL WELLS</td>
<td>10,998</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>
Lower risk categories 6 and 7 had lower potential barrier failure rates, 2.33% and 3.01% respectively. Even though these wells had production casing cement tops above the top of gas, they demonstrate the challenging geologic conditions that are present in the Wasatch Group that confirms the difficulty in creating effective production cement isolation and challenges preventing SAP from shallow hydrocarbon deposits.

Higher concentrations of potential barrier failures occurred in the Mamm Creek Field near the towns of Rifle and Silt, where the core of oil and gas exploration is centered (Figure 5.17). 18% of wells that were originally completed in 2003 had potential barrier failures, which represents the most potential barrier failures for wells completed in a calendar year (Figure 5.18).

Figure 5.17  Map of potential barrier failures color coded by the well’s original wellbore barrier category with locations and depths of water wells in the Piceance Basin – Garfield County.
Figure 5.18 Histogram of potential barrier failures color coded by their original wellbore barrier category in the Piceance Basin – Garfield County.

The higher potential barrier failure rates experienced for lower risk wellbore barrier designs in the field are due to corrosion or ineffective cement coverage behind the casing strings. Due to the high salinity of the produced water in the Piceance Basin and the average elevated mole fraction of CO$_2$ in the production gas stream, many wells in Garfield County have a higher risk of carbon-steel corrosion. Gas analyses were supplied by an independent operator from 205 comingled wells in Mamm Creek Field, Piceance Basin. The average CO$_2$ mole percentage in these wells was high, averaging 3.291% of the produced gas stream (Figure 5.19). This high CO$_2$ mole fraction and higher relative TDS from the produced water can lead to corrosion of the carbon-steel pipe wall if untreated. Many cement remediation jobs occur due to holes and pitting developing in the carbon-steel casing due to anodic deterioration of the pipe wall.
Proper treatment of this corrosion potential is paramount in order to prevent casing leaks and deterioration of the pipe wall. Chemical batch treatments are in place for many operators in the field to combat the effects of corrosion. Many potential barrier failures were a direct result of this elevated corrosive environment.

![Figure 5.19 Average comingled gas composition for 205 wells in the Mamm Creek Field, Piceance Basin – Garfield County.](image)

The Wasatch Group contains localized fracture systems and can contain trace amounts of thermogenic gas which naturally seeped up from the Williams Fork Formation through geologic time. Gas shows during drilling at shallow depths demonstrate the presence of hydrocarbons in the Wasatch Group. SAP is common in the field due to these shallow gas shows above the top of the production cement in the annulus. In addition, effective cement isolation is challenging due to lost circulation in
the Wasatch Group, which ultimately leads to the observance of SAP. Cement remediation is common in response to this observed high SAP in the basin due to these shallow gas accumulations above the designated top of gas. In 2004, the COGCC issued requirements for regular bradenhead pressure monitoring in the Piceance Basin. Under this new regulation, any SAP above 150 psi requires operators to remediate the annular pressure buildup.

5.8 Piceance Basin Catastrophic Barrier Failure Overview

Nine of 10,842 originally producing wells were identified as having catastrophic barrier failures related to hydrocarbon migration to fresh water aquifers in the Piceance Basin, Garfield County (Table 5.3). All nine wells had observed high SAP prior to thermogenic gas detection in offset water wells. No evidence of hydraulic fracturing fluid migration to fresh water aquifers or surface soil was found in this study in the Piceance Basin.

Table 5.3 Catastrophic barrier failures in the Piceance Basin – Garfield County

<table>
<thead>
<tr>
<th>PICEANCE GARFIELD COUNTY WELLS</th>
<th>ORIGINAL WELL COUNT</th>
<th>CATASTROPHIC BARRIER FAILURES</th>
<th>CATASTROPHIC FAILURE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>48</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>145</td>
<td>2</td>
<td>1.38%</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>509</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>1,789</td>
<td>2</td>
<td>0.11%</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>6,233</td>
<td>4</td>
<td>0.06%</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>1,862</td>
<td>1</td>
<td>0.05%</td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>60</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>90</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>105</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>1</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>10,842</td>
<td>9</td>
<td>0.08%</td>
</tr>
<tr>
<td>D&amp;A</td>
<td>156</td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL WELLS</td>
<td>10,998</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Catastrophic barrier failures occurred on two category 3 wells, two category 5 wells, four category 6 wells and one category 7 well (Figure 5.20). Seven catastrophic barrier failures occurred on wells that had the TOC of production cement above the top of gas in the basin. This demonstrates the challenges in effectively isolating shallow gas shows in the Wasatch Group, higher carbon-steel corrosion rates and the ineffectiveness of annular hydrostatic pressure barriers in the field.

Figure 5.20 Map of catastrophic barrier failures color coded by their original wellbore barrier category with locations and depths of water wells in the Piceance Basin – Garfield County.

5.9 Piceance Basin Catastrophic Barrier Failures

Four oil and gas wells were drilled on the same pad in 2001 that were identified as catastrophic barrier failures: 05-045-07651 was an original category 6 well, 05-045-07652 was an original category 5 well, 05-045-07654 was an original category 3 well and 05-045-07653 was an original category 3 well. All four wells on the pad had SAP prior to being hydraulically fractured. However, the original production TOC of these wells was above the Williams Fork Formation. In 2001, an offset water well, 800 ft radial distance from the center of the pad, tested positive for thermogenic gas based on isotopic and compositional analysis. The presence of thermogenic gas detected in the
offset water well appeared to be from the Wasatch Group, and a conduit pathway for hydrocarbon migration was coming from one or all four oil and gas wells based on high SAP observations. Bradenhead gas samples were obtained from all wells. However, due to bacterial degradation of the water well gas samples, no definitive match existed between the gas samples taken from the bradenhead and water well. Due to the proximity of the water well and the adjacent four oil and gas wells, the COGCC issued a violation to the operator for violating rule 209 for not properly isolating gas from water strata and rule 324A for unauthorized discharge of gas to fresh water sources. 05-045-07651 didn’t receive cement remediation and is still a category 6 well but was determined to be a catastrophic barrier failure. The remaining three wells received cement remediation. 05-045-07654 and 05-045-07653 are now category 4 wells and 05-045-07652 is now a category 7 well.

Four wells were drilled on the same pad between 2003 and 2004 that were identified as catastrophic barrier failures: 05-045-09118, 05-045-09465, and 05-045-09462 were originally category 6 wells and 05-045-09463 was an original category 7 well. The 05-045-09118 well began its initial hydraulic fracture treatment in 2004 while the remaining wells had not commenced hydraulic fracturing treatments. Thermogenic gas was detected in an offset water well 860 ft radial distance from the center of the pad based on isotopic and compositional analysis. The thermogenic gas detected in the water well had similar isotopic and compositional characteristics as Williams Fork gas which was similar to the bradenhead gas samples from all four oil and gas wells. High SAP was observed on all four wells and subsequent cement remediation was performed below the surface casing shoe on these wells. The COGCC issued a violation to the operator for violating rule 209 for not properly isolating gas from water strata, rule 324A for unauthorized discharge of gas to fresh water sources and rule 327 for allowing uncontrolled blowing of gas. All four wells were remediated and are now category 7 wells.

The 05-045-09306 well was drilled in 2004 as an original a category 5 well. The operator of the oil and gas well initially reported the TOC of production cement at surface to the COGCC which was later corrected. While drilling the well, the operator encountered lost circulation at a depth of 1,543 ft and had observed a subsequent gas
influx coming from the Wasatch Group. The well also experienced lost circulation prior to performing the production cement job. Production cement was pumped on the well and 25 bbls of cement was originally witnessed at surface by the operator and cementing company. The operator ran a CBL prior to completion operations and interpreted the effective top of cement had dropped to 3,500 ft. The operator had subsequently hydraulically fractured the well without any prior cement remediation. The well had SAP of 500 psi after the well was on production.

The COGCC required a temperature survey to determine the effective TOC of production cement. This temperature survey indicated that the effective TOC of production cement was below the top of the Williams Fork Formation at 4,328 ft. Thermogenic gas migration originated in the oil and gas well’s production casing annulus due to ineffective cement isolation and gas bubbles were observed in the West Divide Creek, which was adjacent to the oil and gas well. Isotopic and compositional analysis was performed on adjacent water wells and the West Divide Creek seep. The COGCC determined that the source of the thermogenic gas was coming from the 05-045-09306 well. The operator was issued a violation for violating rule 317i for failure to pump cement 200 ft above the shallowest producing horizon, rule 301 for not reporting the incident to the COGCC, and rule 324A for failure to prevent adverse environmental impacts to air, water, soil or biological resources. The well was later remediated and is currently a category 7 well.

It was observed that catastrophic barrier failure rates were common in moderate to low risk wellbore barrier designs due to the challenges of combating corrosion of the production casing, effectively isolating hydrocarbon migration with cement in the casing annulus and ineffective annular hydrostatic barriers at shallow depths. 0.08% of the wells in the dataset experienced a complete wellbore barrier failure. This validates that the risk of hydrocarbon migration related to oil and gas operations to fresh water aquifers is low. No evidence of fracturing fluid migration to fresh water aquifers was detected in the study. Formations that are hydraulically stimulated are at depths in excess of 4,000 ft subsurface. Even with the highly fractured nature of the Wasatch Group above the top of the Williams Fork Formation, it still acts a solid geologic barrier preventing height growth of artificially stimulated fractures to fresh water strata.
However, the higher rate of catastrophic barrier failures related to hydrocarbon migration to fresh water aquifers or surface soil, compared to the Wattenberg Field, reveals the different and challenging geologic conditions in the Piceance Basin. A defined geologic barrier is not present that separates shallow fresh water sources from lower hydrocarbon bearing formations. The top of gas designation in the field is determined by commercial quantities of oil and gas, which is generally below the top of the Williams Fork Formation. The COGCC issued mandatory bradenhead testing in the Rulison and Mamm Creek Field after the catastrophic barrier failure related to the West Divide Creek seep in 2004. SAP is commonly observed in the field due to shallow gas shows in the Wasatch Group and high rates of carbon-steel corrosion due to the corrosive nature of the produced gas.

The Wasatch Group is considered a fresh water aquifer at shallow depths and it also contains thermogenic gas that naturally migrated upwards in the natural fractures from the lower Mesaverde Group. There were four catastrophic barrier failures that were related to thermogenic gas migration from deeper horizons in the Wasatch Group to shallower fresh water bearing strata in the same formation.

5.10 Piceance Basin Existing Conditions

Six percent, or 602 of the 10,507 existing producing or shut-in wells in Garfield County, currently have shallow surface casing in relation to the deepest water well drilled in the county. Of these 602 wells, 143 wells currently have higher risk category 2 and 3 well barrier designs. These designs don’t have the TOC of production cement above the surface casing shoe. 132 of these wells are currently in the vicinity of a water well (Figure 5.21).

3.48% of the wells in the sample set experienced SAP, had a cement remediation or a combination of both. This higher potential failure rate relative to the Wattenberg Field is explained by the shallow gas shows from the Wasatch Group, difficulty eliminating shallow gas shows with effective cement coverage and higher rates of corrosion of the production casing due to the relatively higher TDS from the produced water and over three mole percent CO\(_2\) in the produced gas. In order to isolate annular migration, it is recommended that the operators extend production cement above the
previous casing shoe, potentially with cement stage-tools in order to combat lost circulation zones, and routinely chemically batch treat the wells to reduce the effects of corrosion of the pipe walls. Although, current state orders to monitor bradenhead pressure in the Rulison and Mamm Creek Fields prevent operators from extending production cement to surface in order to monitor pressure buildup.

Figure 5.21 Map of existing higher risk wells with shallow surface casing in the Piceance Basin – Garfield County.

94% of the wells in the Piceance Basin, Garfield County, have surface casing set below 600 ft, the deepest water well in the field (Figure 5.23). The Wasatch Group is geologically different than the Wattenberg Field’s Pierre Shale, which underlies the Fox-Hills fresh water aquifer and acts as an impermeable geologic barrier protecting the aquifer system. On the other hand, the Wasatch Group has the presence of shallow gas and is naturally fractured, which can cause natural thermogenic gas migration to shallower depths. A key finding is that fresh water is sourced from a formation that naturally contains thermogenic gas in Garfield County.
Figure 5.22  Map of existing producing or shut-in wells color coded by their current wellbore barrier category in the Piceance Basin – Garfield County.
The Raton Basin, in Huerfano and Las Animas Counties, Colorado, is located in the south-east area of the state, and extends into New Mexico (Figure 6.1). The basin has a long history of coal mining due to the shallow coal deposits in the Raton Formation and close proximity of local steel plants in Pueblo. Significant oil and gas development commenced in the early 1990s, mostly from coalbed methane (CBM) wells that targeted the Vermejo and Raton Formations. Deeper wells are also drilled that target the Niobrara Formation and Dakota Group in Huerfano County. Overall, the Raton Basin in Colorado is sparsely populated region.

Figure 6.1 Geographic location of the Raton Basin, Colorado.
6.1 Raton Basin Geology

The Western Interior Seaway submerged the Raton Basin during the Cretaceous period, with sea levels transgressing and regressing throughout time. The Upper Cretaceous Trinidad Sandstone and Vermejo Formation, which contains coal deposits, are two hydrocarbon bearing sandstones above the Pierre Shale. The Raton Formation, which is Paleocene in age, includes two coal deposits which are the primary target intervals for CBM wells in the basin (Flores and Bader 1999). Above the Raton Formation is the Poison Canyon Formation, which is 0 – 500 ft thick and is a part of the aquifer system in the basin (Figure 6.2). Deeper exploration also targets the Lower Cretaceous Dakota Group and Upper Cretaceous Niobrara Formation in Huerfano County. The Raton Basin in Colorado, is bounded by the Sangre de Cristo Mountains on the west. Overall, the basin is structurally shallower than previous basins presented.

Figure 6.2  Geologic stratigraphic column and apparent formation thickness in the Raton Basin (Flores and Bader 1999).
6.2 Raton Basin Population Density

The Raton Basin in Colorado encompasses Las Animas and Huerfano Counties, which are sparsely populated areas in the state. Trinidad is the only major city located in Las Animas County; 63% of the population resides within the city limits, which is east of the core area of oil and gas exploration in the basin. The county is 4,775 square-miles in size and has a 2013 population density of 3.2 persons per square-mile (US Census 2013). The population of Las Animas County has remained relatively flat since 1970 (Figure 6.3).

Huerfano County is located north-west of Las Animas County and encompasses one major city, Walsenburg. 64% of the county’s population resides in Walsenburg. The county is 1,593 square-miles in size and has a 2013 population density of 2.2 persons per square-mile (US Census 2013). The population of Huerfano County has also remained relatively flat since 1970 (Figure 6.4).

Figure 6.3 Population of Las Animas County, Colorado from 1970 to 2013 (US Census 2013).
Figure 6.4  Population of Huerfano County, Colorado from 1970 to 2013 (US Census 2013).

6.3  Raton Basin Water Sourcing

Water wells in the Raton Basin are drilled into either coalbeds from the Raton or Vermejo Formations or into sandstones from the Cuchara-Poison Canyon Formation, which can contain both fresh water and naturally occurring methane. These water wells pump water off of the surface of the coal deposits, known as dewatering, which causes the methane to desorb from the surface of the coal and dissolve into the water stream. Since oil and gas development and local water sourcing are generally from the same formations, it can be problematic determining the origin of increased methane concentrations in water wells resulting from oil and gas development. There are two main aquifer systems in the Raton Basin: the Cuchara-Poison Canyon and the Raton-Vermejo-Trinidad (Watts 2006).
Data from 527 water wells from the COGCC water well database in the Raton Basin, Colorado, were collected. However, 295 water wells didn’t have a reported depth in the database. The deepest reported depth of a water well in the field is 960 ft. 66% of the water wells with reported depths were less than 300 ft and many shallow water wells are in close proximity to deeper water wells (Figure 6.5). Therefore, the average reported water well depth in the study area is 188 ft subsurface and was used as the depth marker for shallow and deep surface casing designations in the basin.

Figure 6.5 Map of water well locations and depths in the Raton Basin, Colorado.

6.4 Raton Basin Data Sourcing and Assumptions

Oil and gas well data was acquired from COGCC database. Potential barrier failures were identified by evidence of remedial cement on any casing string with the assumption that the oil and gas well experienced SAP as reason for remediation. However, a root cause for cement remediation in the Raton Basin is often due to COGCC rule 303F, which requires the production cement top to be above the previous casing shoe in the basin. Many operators were required to remedially cement wells in
accordance to this rule and not necessarily due to the observation of SAP. However, for this study the assumption is any cement remediation on any casing string in the Raton Basin is identified as a potential barrier failure.

Catastrophic barrier failures were identified by thermogenic gas detected in offset water wells or surface soil and evidence of a well barrier failure(s) in an off-set oil and gas well which contributed to thermogenic gas migration to a fresh water aquifer or surface. Shallow surface casing in the Raton Basin is defined as being set above any total depth of a water well within a 0.5-mile radius of an oil and gas well or less than 188 ft subsurface, due to the average water well depth in the field, for oil and gas wells that are not within a 0.5-mile radius of a water well. No defined fresh aquifer base depths were apparent.

The TOC of production cement was supplied by the individual well scout cards in the COGCC database. However, if the depth of the cement top was not supplied or appeared inaccurate, the quantity of cement was used to calculate the estimated top of cement based on a uniform wellbore geometry and typical yields for class H cement, 1.18 ft$^3$/sack of cement. Many wells in the field have un-cemented production liners that extend from the intermediate casing shoe. In these instances, the intermediate casing was defined as the production casing for categorization. Tubing and packers are neglected in this study as an additional barrier.

The top of gas in the Raton Basin, Colorado was defined as the top of the Raton Formation. Any cement top that didn’t exceed the top of the Raton Formation was properly categorized. If the top of the Raton Formation was not supplied by the individual well’s scout card in the COGCC database, then an average depth of the Raton Formation was used and corrected for an oil and gas well’s topographic elevation.

6.5 Raton Basin Historical Wellbore Designs

3,547 oil and gas wells were identified that were drilled and completed from 1920 until December 2013 in the Raton Basin, Colorado. Of which, 3,359 wells were originally producing or shut-in and 188 wells were drilled and subsequently plugged and abandoned. There are nine common original wellbore barrier designs in the basin.
(Table 6.1). No wells in the basin were identified as having the highest risk category 1 or lower risk category 9 or 12 well barrier designs. The highest risk barrier designs in the basin are wells with shallow surface casing, which include categories 2 - 4.

Table 6.1 Original well count by wellbore barrier category in the Raton Basin, Colorado

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ORIGINAL WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>23</td>
</tr>
<tr>
<td>3</td>
<td>4</td>
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<tr>
<td>4</td>
<td>45</td>
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<td>5</td>
<td>399</td>
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<tr>
<td>6</td>
<td>32</td>
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<tr>
<td>7</td>
<td>2,800</td>
</tr>
<tr>
<td>8</td>
<td>7</td>
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<td>9</td>
<td>0</td>
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<td>10</td>
<td>20</td>
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<tr>
<td>11</td>
<td>29</td>
</tr>
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<td>12</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,359</td>
</tr>
<tr>
<td>DRILLED AND ABANDONED WELL COUNT</td>
<td>188</td>
</tr>
<tr>
<td>TOTAL WELL COUNT</td>
<td>3,547</td>
</tr>
</tbody>
</table>

The exploration phase of development in the Raton Basin, Colorado, occurred prior to 1995, with only 173 wells drilled prior to that year in the data sample set. 3,186 wells were drilled between 1995 and 2014 (Figure 6.6). However, there has been a significant drop in well counts since 2009 after the collapse in gas prices due to the global financial crises. The low volume of dry methane gas produced from the CBM wells is considered uneconomic for operators in the current pricing environment since 2009.

The most common wellbore barrier design in the Raton Basin is category 7. 2,800 category 7 wells were completed out of 3,547 wells. The second most common
design was category 5 wells. 399 category 5 wells were completed in the field. However, this design had many cement remediation jobs due to the TOC of the production cement below the top of the Raton Formation, which is designated the top of gas in the basin. The highest well density is west of Trinidad and south of Walsenburg (Figure 6.7).

![Histogram of originally completed wells color coded by their original wellbore barrier category in the Raton Basin, Colorado.](image)

Figure 6.6 Histogram of originally completed wells color coded by their original wellbore barrier category in the Raton Basin, Colorado.

Average surface casing setting depths have increased since 1996 to 500 – 600 ft subsurface (Figure 6.8). However, the original average top of production cement has decreased since 2004 to 800 ft subsurface, due to the deeper surface casing setting depths (Figure 6.9, see page 100). Due to the COGCC rule 303F, which requires that the production cement top to be above the previous casing shoe, many cement remediation jobs were performed in accordance to this rule (Figure 6.10, see page 101). After cement remediation, the current average production cement top is now less than 400 ft subsurface.
Figure 6.7 Map of originally completed wells color coded by their original wellbore barrier category in the Raton Basin, Colorado.
Figure 6.8  Chronologic original surface casing setting depths in the Raton Basin, Colorado.
Figure 6.9  Chronologic original top of production cement depths in the Raton Basin, Colorado.
Figure 6.10  Chronologic current top of production cement depths after cement remediation in the Raton Basin, Colorado.

6.6  Raton Basin Wellbore Barrier Categories

Category 2 well barrier designs have shallow surface casing and the TOC of production cement below the top of the Raton Formation (Figure 6.11). These wells only have a single annular hydrostatic barrier preventing hydrocarbon migration to the fresh water aquifer. Twenty-three wells existed with this design and they had an average original completion date of 1983. The most probable hydrocarbon migration flow path is in the production casing annulus for this design.

Category 3 well barrier designs have shallow surface casing and the TOC of production cement above the top of the Raton Formation (Figure 6.12). These wells only have a single annular hydrostatic barrier preventing hydrocarbon migration to the fresh water aquifer. Only four wells existed with this design and they had an average
The original completion date of 1993. The most probable hydrocarbon migration flow path is in the production casing for this design.

Figure 6.11 Wellbore diagram of a category 2 wellbore barrier design in the Raton Basin, Colorado.
Figure 6.12 Wellbore diagram of a category 3 wellbore barrier design in the Raton Basin, Colorado.

Category 4 well barrier designs have shallow surface casing and the TOC of the production cement above the surface casing shoe (Figure 6.13). These wells only have two barriers preventing hydrocarbon migration to the fresh water aquifer: production casing and production cement. Forty-five wells existed with this design and they had an
average original completion date of 1995. The most probable hydrocarbon migration flow path is in the production casing for this design.

Figure 6.13 Wellbore diagram of a category 4 wellbore barrier design in the Raton Basin, Colorado.

Lower risk dual string barrier designs have deep surface casing. These designs include categories 5 – 7. Category 5 well barrier designs have deep surface casing and
the TOC of production cement below the top of the Raton Formation (Figure 6.14). These wells have three barriers preventing hydrocarbon migration to the fresh water aquifer: annular hydrostatic pressure, surface casing and surface cement. 399 wells existed with this design and they had an average original completion date of 2003. The most probable hydrocarbon migration flow path is in the production casing annulus for this design.

![Wellbore diagram of a category 5 wellbore barrier design in the Raton Basin, Colorado.](image)

Figure 6.14 Wellbore diagram of a category 5 wellbore barrier design in the Raton Basin, Colorado.
Category 6 well barrier designs have deep surface casing and the TOC of the production cement above the top of the Raton Formation (Figure 6.15). These wells have three barriers preventing hydrocarbon migration to the fresh water aquifer: production casing, surface casing and surface cement. Thirty-two wells existed with this design and they had an average original completion date of 2004. The most probable hydrocarbon migration flow path is in the production casing for this design.

Figure 6.15 Wellbore diagram of a category 6 wellbore barrier design in the Raton Basin, Colorado.
Category 7 well barrier designs have deep surface casing and the TOC of production cement above the surface casing shoe (Figure 6.16). This design is the most common in the basin. These wells have four barriers preventing hydrocarbon migration to the fresh water aquifer: production casing, production cement, surface casing and surface cement. 2,800 wells existed with this design and they had an average original completion date of 2003. The most probable hydrocarbon migration flow path is in the production casing for this design.

Figure 6.16  Wellbore diagram of a category 7 wellbore barrier design in the Raton Basin, Colorado.
Categories 8 – 12 are three string casing designs that incorporate an additional intermediate casing string. Category 8 well barrier designs have deep surface casing, a deep intermediate casing with the TOC of intermediate casing cement above the surface casing shoe and the TOC of the production cement below the top of the gas (Figure 6.17). This design is not very common in the field; only seven wells existed with this design and which had average original completion date of 2001. These wells have five barriers preventing hydrocarbon migration to the fresh water aquifer: annular hydrostatic pressure, intermediate casing, intermediate cement, surface casing and surface cement. The most probable hydrocarbon migration flow path is in the production casing annulus for this design.

![Wellbore Diagram of Raton Category 8 Wellbore Barrier Design](Figure 6.17)

Figure 6.17 Wellbore diagram of a category 8 wellbore barrier design in the Raton Basin, Colorado.
No category 9 well barrier designs exist in the field. Category 10 and 11 wells are the lowest risk barrier designs in the field and were intended for deeper wells targeting the Niobrara Formation and Dakota Group. Category 10 well barrier designs have deep surface casing, deep intermediate casing with the TOC of intermediate cement above the surface casing shoe, and the TOC of production cement above the top of gas (Figure 6.18). Twenty wells existed with this design which had an average original completion date of 1996. These wells have six barriers preventing hydrocarbon migration to the fresh water aquifer: production casing, annular hydrostatic pressure, intermediate casing, intermediate cement, surface casing and surface cement. The most probable hydrocarbon migration flow path is in the production casing for this design.

Figure 6.18 Wellbore diagram of a category 10 wellbore barrier design in the Raton Basin, Colorado.
Category 11 well barrier designs have similar surface and intermediate casing and cement depths and tops as category 10 wells. However, this design also has the TOC of production cement above the intermediate casing shoe (Figure 6.19). 29 wells existed with this design and they had an average original completion date of 2002. These wells have six barriers preventing hydrocarbon migration to the fresh water aquifer: production casing, production cement, intermediate casing, intermediate cement, surface casing and surface cement. The most probable hydrocarbon migration flow path is in the production casing for this design. No category 12 well barrier designs occur in the field.

Figure 6.19 Wellbore diagram of a category 11 wellbore barrier design in the Raton Basin, Colorado.
6.7 Raton Basin Potential Barrier Failures

Potential barrier failures were identified by remedial cement jobs performed on the surface casing, intermediate casing or production casing in the Raton Basin, Colorado. 363 of 3,359 originally producing or shut-in wells in the basin experienced a potential barrier failure, which correlates to a 10.81% potential barrier failure rate (Table 6.2). This rate of potential barrier failure is much higher than previously presented basins primarily due to COGCC rule 303F, which requires that production casing cement tops must be above the previous casing shoe. The majority of the cement remediation jobs were in agreement with this rule and not necessarily due to the presence of SAP. However, this study defines any cement remediation on wells in the Raton Basin as a potential barrier failure.

Table 6.2 Potential barrier failures in the Raton Basin, Colorado

<table>
<thead>
<tr>
<th>CATG.</th>
<th>WELL COUNT</th>
<th>BARRIERS</th>
<th>BARRIERS %</th>
<th>AVG WEL AGE</th>
<th>P&amp;A WEL</th>
<th>CURRENT WEL</th>
<th>SURFACE DEPTH</th>
<th>INT 1 TOC</th>
<th>TOP CEMENT</th>
<th>TOP PROD</th>
<th>AVG TGT DEPTH</th>
<th>AVG TGT TOC</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
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<td>0</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>23</td>
<td>2</td>
<td>8.70%</td>
<td>1983</td>
<td>20</td>
<td>3</td>
<td>98</td>
<td>1,828</td>
<td>1,828</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>4</td>
<td>1</td>
<td>25.00%</td>
<td>1993</td>
<td>3</td>
<td>1</td>
<td>23</td>
<td>403</td>
<td>403</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>45</td>
<td>1</td>
<td>2.22%</td>
<td>1995</td>
<td>10</td>
<td>35</td>
<td>102</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>399</td>
<td>322</td>
<td>80.70%</td>
<td>2003</td>
<td>63</td>
<td>45</td>
<td>516</td>
<td>1,433</td>
<td>1,433</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>6</td>
<td>32</td>
<td>19</td>
<td>59.38%</td>
<td>2004</td>
<td>1</td>
<td>15</td>
<td>845</td>
<td>1,454</td>
<td>1,454</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>2,800</td>
<td>12</td>
<td>0.43%</td>
<td>2003</td>
<td>234</td>
<td>2,873</td>
<td>494</td>
<td>62</td>
<td>62</td>
<td></td>
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</tr>
<tr>
<td>8</td>
<td>7</td>
<td>3</td>
<td>42.86%</td>
<td>2001</td>
<td>0</td>
<td>4</td>
<td>555</td>
<td>2,128</td>
<td>99</td>
<td>3,569</td>
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</tr>
<tr>
<td>9</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>20</td>
<td>2</td>
<td>10.00%</td>
<td>1996</td>
<td>11</td>
<td>9</td>
<td>570</td>
<td>2,785</td>
<td>432</td>
<td>3,673</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>29</td>
<td>1</td>
<td>3.45%</td>
<td>2002</td>
<td>10</td>
<td>22</td>
<td>677</td>
<td>2,965</td>
<td>244</td>
<td>2,379</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,359</td>
<td>363</td>
<td>10.81%</td>
<td>352</td>
<td>3,007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

D&A 188
TOTAL WELLS 3,547

The highest potential barrier failure rate occurred on category 5 and 6 wells. 80.70% of the category 5 wells and 59.38% of the category 6 wells had cement remediation jobs due to the TOC of production cement below the surface casing shoe. However, the most common original barrier design is category 7, which had the lowest potential barrier failure rate, 0.43%, due to its redundant barrier designs and TOC of production cement above the surface casing shoe. The highest concentration of
potential barrier failures occurred west of Trinidad, where the highest density of oil and gas wells exist (Figure 6.20).

![Map of potential barrier failures color coded by their original wellbore barrier category with locations and depths of water wells in the Raton Basin, Colorado.](image)

Figure 6.20 Map of potential barrier failures color coded by their original wellbore barrier category with locations and depths of water wells in the Raton Basin, Colorado.

265 of 1,341 wells that were completed between 2005 and 2008, experienced remedial cement jobs and were identified as potential barrier failures (Figure 6.21). 80.70% of category 5 wells received cement remediation in the basin due to the TOC of the production cement which was below the top of gas. Category 7 wells are the most common in the basin, which have deep surface casing and the TOC of production cement above the surface casing shoe. 0.43% of category 7 wells received cement remediation due to cement contamination, the presence of a micro-annulus or cement cracking.
6.8 Raton Basin Catastrophic Barrier Failure Overview

The catastrophic barrier failure rate in the Raton Basin is higher than the findings for the Wattenberg Field and Piceance Basin (Garfield County, Colorado). 0.09% of wells experienced a catastrophic barrier failure, or three of 3,359 original producing or shut-in wells (Table 6.3). The basin’s geology is an important factor for wellbore barrier designs. Coal deposits are evident on the eastern area of the field at surface. The coal deposits naturally contain methane and fresh water. Water wells drilled into the Poison Canyon Formation, Raton-Vermejo-Trinidad Formations can produce both water and methane from the coals.

CBM wells in the Raton Basin are typically hydraulically fractured with fresh water, additives, nitrogen, and silica sand in order to create higher conductivity. One complaint was filed with the COGCC regarding the hydraulic fracturing of a single gas well. However, the findings of the COGCC were conclusive that the hydraulically
fractured gas well didn’t cause alteration in the water quality of the adjacent water well. The owner of the water well complained of turbidity in the quality of the water produced from the water well. The COGCC determined that the turbidity of the water produced from the water well was related to a shock chlorination treatment performed by the owner of the water well prior to the hydraulic fracture treatment of the gas well. Chemical composition of the hydraulic fracturing fluid didn’t comply with the water test results from the water well. No direct evidence exists that any of the hydraulic fracturing operations contaminated the fresh water sources in the basin. All catastrophic barrier failures were related to hydrocarbon migration and not hydraulic fracturing fluid.

Table 6.3 Catastrophic barrier failures in the Raton Basin, Colorado

<table>
<thead>
<tr>
<th>RATON BASIN WELLS</th>
<th>ORIGINAL WELL COUNT</th>
<th>CATASTROPHIC BARRIER FAILURES</th>
<th>CATASTROPHIC FAILURE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>23</td>
<td>1</td>
<td>4.35%</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>4</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>45</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>399</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>32</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>2,800</td>
<td>2</td>
<td>0.07%</td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>7</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>20</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>29</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,359</td>
<td>3</td>
<td>0.09%</td>
</tr>
<tr>
<td>D&amp;A</td>
<td>188</td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL WELLS</td>
<td>3,547</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Three catastrophic barrier failures were identified in this study: one category 2 well and two category 7 wells (Figure 6.22). However, the catastrophic barrier failures related to the category 2 well and one category 7 well, were due to ineffective plugging and abandonment of the wellbores. Thermogenic gas migration was not observed on these wells prior to being plugged. This reveals the complications in monitoring and
effectively plugging and abandoning older wellbores in the basin. Due to the shallow nature of the producing formations and the presence of methane in coal deposits near the surface, it is often difficult to determine if methane is naturally present in the aquifer system or if it naturally migrated from deeper sources.

![Figure 6.22 Map of catastrophic barrier failures with locations and depths of water wells in the Raton Basin, Colorado.](image)

6.9 Raton Basin Catastrophic Barrier Failures

Well 05-071-06045 was originally completed as a category 2 well in 1980 and subsequently plugged and abandoned in 1984. A residential structure was under construction in 2007 above the old plugged and abandoned location of the wellbore. On April 17, 2007, the residential structure, under construction, exploded but was unoccupied at the time of the explosion. High methane levels were detected in the soil samples surrounding the incident site and it was determined that the source was from the original plugged and abandoned wellbore, which had been improperly plugged in
1984. The well was originally drilled by the City of Trinidad and funded by the U.S. Department of Energy to the American Public Gas Association as part of a program to test coalbed methane. The City of Trinidad denied operatorship of the well according to subsequent hearings. However, the COGCC issued a violation to the City of Trinidad for violating rule 319A, which requires all wells to be plugged to permanently prevent migration of gas to surface or alternate formations. The 05-071-06045 wellbore was subsequently re-plugged to prevent further hydrocarbon migration.

In June 2007, a water well pump house exploded in Huerfano County. The methane source of the explosion was determined to be thermogenic in nature. Well 05-055-06292 and well 05-055-06148, which were originally completed with category 7 well barrier designs in 2005 and 1998, respectively, were adjacent to the explosion site. The 05-055-06148 well was plugged and abandoned by the operator in 1998, but according to the NAOV report, the operator had difficulties effectively plugging the wellbore. Well 05-055-06292 experienced SAP prior to the explosion. Water well testing and soil samples were collected in the vicinity of the 05-055-06148 well, which all indicated high levels of methane which is characteristic of the Raton Formation. The operator acknowledged the existence of the methane migration and voluntarily shut-in fifty-two adjacent gas wells in 2007, in the vicinity of the incident (Figure 6.23). No violations were issued to the operator due to inconclusive evidence of the methane migration source. The operator subsequently plugged and abandoned all fifty-two wells in the field that were next to the explosion site (Norwest Applied Hydrology 2008). Due to the proximity of the two gas wells aforementioned, they have been determined to be catastrophic barrier failures.

The Raton Basin, Colorado, contains several orphaned plugged and abandoned wells that were drilled in the early 20th century. One such well is the Florence Oil and Refining Company #1 (05-043-40078). Soil gas samples were collected in 2009, near the site of the Florence Oil and Refining Company #1 wellbore. These samples showed high methane levels. The COGCC sets aside funding for old orphaned wells in order to remediate any environmental damages associated with hydrocarbon migration to fresh water aquifers or surface soils. This well was not included in the data set due to its age and lack of complete wellbore construction data. This study is limited to wells that have
complete data associated with well construction. Orphaned wells that were drilled nearly 100 years ago can be a concern in legacy fields due to incomplete data associated with their initial development and potential ineffective plugging and abandoning methodologies.

Figure 6.23  Map of 52 gas wells that were plugged and abandoned related to the catastrophic barrier failures of the well 05-055-06292 and well 05-055-06148 in the Raton Basin, Colorado.

In 2009, the COGCC initiated rule 608 for Coalbed Methane development. This rule required operators to identify all plugged and abandoned wells within 0.25-mile of a proposed CBM well and ascertain the quality of the plugged and abandoned wells. Soil gas surveys are to be collected near any plugged and abandoned well. Additionally, baseline water well testing must be accomplished within 0.5-mile radius of the CBM well. Bradenhead testing is required on a biennial basis for all CBM wells.

Three originally producing oil and gas wells experienced a catastrophic barrier failure related to hydrocarbon migration to fresh water aquifers or surface soil in the
Raton Basin, Colorado, representing a 0.09% catastrophic barrier failure rate. This low catastrophic barrier failure rate is due to 83.36% of wells with lower risk category 7 well barrier designs. No conclusive evidence of fracturing fluid migration to fresh water aquifers was detected in the dataset.

Two category 7 wells were identified that had catastrophic barrier failures. However, one of the category 7 well failures was related to improperly plugging and abandoning the wellbore and was not related to the initial wellbore design. The second category 7 well failure was inconclusive of direct causation according to COGCC NAOV filings but was determined to be a catastrophic barrier failure for this analysis.

It was observed that catastrophic barrier failures occurred in high risk and low risk wellbore barrier designs due to the shallow depths of the Raton Formation’s coal deposits. Many water wells are also drilled into the Raton Formation. The higher catastrophic barrier failure rate in the Raton Basin, compared to the previous basins presented, is due to the shallow hydrocarbon bearing formations, which are often the same formations that fresh water is sourced. In addition, problems exist with identifying orphaned plugged and abandoned wells in the basin and ascertaining the effectiveness of their original plugging and abandonments.

6.10 Raton Basin Existing Conditions

98.7% of the existing producing or shut-in wells, or 2,968 of 3,007, in the Raton Basin, Colorado, currently have deep surface casing. 1.3% of the existing producing or shut-in wells, or 39 of 3,007, presently have shallow surface casing. The highest risk existing wells are category 2. There exist three wells that are currently producing or shut-in that have this categorization (Figure 6.24). Two of these wells are within a high concentration of water wells and one well is not located near any water well locations reported by the COGCC water well database. Overall, the Raton Basin in Colorado, has 98.7% of remaining wells with lower risk well barrier designs primarily due to COGCC rule 303F and predominantly shallow aquifer base depths (Figure 6.25).
Figure 6.24  Map of existing high risk wellbore barrier designs that have shallow surface casing and the TOC of production cement below the top of gas in the Raton Basin, Colorado.
Figure 6.25  Map of existing wells color coded by their current wellbore barrier category in the Raton Basin, Colorado.
The San Juan Basin, Colorado is located in the south-east region of the state in La Plata and Archuleta Counties, near the Four Corners area (Figure 7.1). The basin extends into New Mexico, encompassing 6,500 square miles (Fassett 2013). Oil and gas exploration in the field primarily began around 1950, targeting the deeper Dakota Group, Mesaverde Group, and the Pictured Cliffs Sandstone. Beginning in the 1970s, CBM wells were drilled targeting coal deposits in the Fruitland Formation (Fassett 2013). 4,189 oil and gas wells were analyzed and categorized based on wellbore barrier construction from 1901 to 2014.

Figure 7.1 Geographic location of the San Juan Basin, Colorado.
7.1 San Juan Basin Geology

The San Juan Basin is a large sedimentary, asymmetric basin that was deposited during the Tertiary geologic time period. The Upper Cretaceous formations were deposited during transgression and regression of the Western Interior Seaway. The deepest target formation is the Dakota Sandstone (Dakota Group), followed by the Mancos Shale. Overlying the Mancos Shale, is the Late Cretaceous Mesaverde Group which was deposited during a regression of the Western Interior Seaway, followed by a transgressional period and the depositing of the Lewis Shale (Figure 7.2) (Fassett 2013).

![Geologic stratigraphic units of the San Juan Basin (Fassett 2013).](image-url)
The Pictured Cliffs Sandstone, which overlies the Lewis Shale, represented another regression of sea levels. The Fruitland Formation was deposited during further regression of the Western Interior Seaway. Above the lower Fruitland Sandstone is the Fruitland Coal, which was deposited in inland marshes, and is the main target for CBM exploration in the basin. The Kirtland Shale lies above the Fruitland Formation, and acts as a geologic seal preventing hydrocarbon migration from the Fruitland Formation below to sedimentary formations near surface. The Tertiary Ojo Alamo Sandstone and Animas Formation were deposited above the Kirtland Shale during the final regression of the Western Interior Seaway (Fassett 2013).

7.2 San Juan Basin Population Density

The San Juan Basin encompasses La Plata and Archuleta Counties, in Colorado. The area is sparsely populated with the main land use for agriculture and coal mining. La Plata County is 1,700 square miles and has a 2013 population density of 30 persons per square mile (US Census 2013). The largest city in proximity to oil and gas development is Durango, which contains 33% of the county’s population. The county has seen significant population growth of 166% since 1970 (Figure 7.3). 95% of the oil and gas wells within the data sample set are located in La Plata County.

![Figure 7.3 Population of La Plata County, Colorado from 1970 to 2013 (US Census 2013).](image)
Archuleta County is 1,356 square miles and has a 2013 population density of 8.9 persons per square mile (US Census 2013). The main city in the county is Pagosa Springs, which has a 2013 population of 1,727 persons. The county is sparsely populated, but has seen significant relative population growth of 355% since 1970 (Figure 7.4). Only five percent of the oil and gas wells in the San Juan Basin, Colorado, are located in Archuleta County.

Figure 7.4  Population of Archuleta County, Colorado from 1970 to 2013 (US Census 2013).

7.3  San Juan Basin Water Sourcing

The aquifer system in the San Juan Basin, Colorado, consists of alluvial aquifers at shallow depths and bedrock aquifers at deeper depths, primarily in the Animas Formation and outcrops of deeper Dakota Sandstone and Pictured Cliffs Sandstone. The principle aquifer system is part of the Animas Formation, above the Ojo Alamo Sandstone. The aquifer is recharged at surface from precipitation and irrigation water. Below the aquifer system is the Kirtland Shale, an impermeable mudrock that acts as a geologic barrier from lower hydrocarbon deposits in the Fruitland Formation (Robson and Wright 1995). The average water well depth in the study area is 169 ft subsurface. 1,808 water wells depths and locations were acquired from the COGCC water well database. The depths of the water wells range between less than 100 ft subsurface to
640 ft in the same geographic area (Figure 7.5). 94.36% of water wells in the San Juan Basin, Colorado, are less than 300 ft subsurface.

Figure 7.5 Map of water well locations and depths in the San Juan Basin, Colorado.

7.4 San Juan Basin Data Sourcing and Assumptions

Oil and Gas well data was acquired from COGCC database. Potential barrier failures were identified by evidence of remedial cement on the surface casing, intermediate casing or production casing with the assumption that the oil and gas well experienced sustained annulus pressure (SAP) as reason for remediation.

Catastrophic barrier failures were identified by thermogenic gas detected in offset water wells or surface and evidence of a well barrier failure(s) in an off-set oil and gas well which contributed to thermogenic gas migration to a fresh water aquifer. The
The deepest fresh water well is 640 ft subsurface in the San Juan Basin, Colorado. The average water well depth in the field is 169 ft subsurface. Shallow surface casing was defined as being set above the average water well depth of 169 ft subsurface for wells that were not within a 0.5-mile radius of an oil and gas well or shallower than an offset water well within a 0.5-mile radius of a water well.

The top of production cement was supplied by the individual well scout cards in the COGCC database. If the depth of the cement top was not supplied, the quantity of cement was used to calculate the estimated top of cement based on wellbore geometry and typical yields for class H cement, 1.18 ft³/sack of cement. Tubing and packers are neglected in this study as an additional barrier.

890 wells were identified as having un-cemented or cemented production liners. For categorization of these wells, the top of intermediate cement was used as the equivalent top of the production cement since the design of the casing is a tapered string.

In addition, if the Fruitland Formation top was not supplied within an individual well scout card, then the average depth of the Fruitland Formation was used with the topographic surface elevation of a well to estimate the top of the Fruitland Formation. This formation is assumed to be the top of gas in the San Juan Basin, Colorado.

### 7.5 San Juan Basin Historical Wellbore Designs

4,189 wells were identified that were drilled and completed in the San Juan Basin, Colorado between 1901 and January 2014. The wellbore barrier designs in the San Juan Basin, Colorado, vary depending on the target formation, local geology and depth of the well. There are two main types of wells: wells that target the Dakota Group, Mancos Shale, Mesaverde Group or Pictured Cliffs Sandstone and CBM wells that target the Fruitland Formation. 358 wells in the dataset were drilled and subsequently plugged and abandoned without being completed. Overall, there are ten common wellbore barrier designs that exist in the San Juan Basin, Colorado (Table 7.1).

Higher risk barrier designs in the San Juan Basin, Colorado are categories 1 – 4; all have shallow surface casing in relation to the depths of water wells within a 0.5-mile radius.
radius of an oil and gas well or deeper than 169 ft for oil and gas wells that are not within a 0.5-mile radius of a water well. No category 1 wells exist in the San Juan Basin data sample set.

Table 7.1 Original well count by wellbore barrier category in the San Juan Basin, Colorado

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ORIGINAL WELL COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>12</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>13</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>71</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>54</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>348</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>2,677</td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>64</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>17</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>148</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>427</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>0</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>3,831</strong></td>
</tr>
</tbody>
</table>

| DRILLED AND ABANDONED WELL COUNT | 358 |
| TOTAL WELL COUNT                 | 4,189 |

The San Juan Basin experienced three time periods of significant drilling and completion activity: 1950 – 1966, 1977 – 1991, and 1997 – 2011 (Figure 7.6). 70% of the completed wells in the San Juan Basin, Colorado, had an original wellbore barrier design of category 7. In 1988, during low commodity prices, a significant uptick in higher relative risk category 4 wells were completed, representing 10% of the wells completed in that calendar year. The highest concentration of wells are located south-east of Durango and west of Pagosa Springs, near the New Mexico border (Figure 7.7).
The average surface casing setting depths has remained relatively flat since 1950, at around 400 ft subsurface (Figure 7.8). The average original top of production cement was elevated near surface beginning in 1983 and subsequently trended lower to 300 – 500 ft beginning in 1995 until 2003 (Figure 7.9, see page 131). Many wells that were originally completed in deeper formations were recompleted to produce from the Fruitland coal. Therefore, it can be determined that not all cement remediation jobs were due to the presence of SAP. After cement remediation on a number of wells that had lower subsurface original production cement tops, the current average production cement top is now near surface (Figure 7.10, see page 132).
Figure 7.7 Map of originally completed wells color coded by their original wellbore barrier category in the San Juan Basin, Colorado.
Figure 7.8 Chronologic original surface casing setting depths in the San Juan Basin, Colorado.
Figure 7.9  Chronologic original top of production cement depths in the San Juan Basin, Colorado.
Figure 7.10 Chronologic current top of production cement depths after cement remediation in the San Juan Basin, Colorado.

7.6 San Juan Basin Wellbore Barrier Categories

Category 2 well barrier designs have shallow surface casing and the TOC of production cement below the top of gas (Figure 7.11). This design is not common in the San Juan Basin and was generally utilized for wells that targeted the Dakota Group at much structurally shallower depths in the basin near the New Mexico border. Only twelve wells existed with this original design and they had an average completion date of 1978. The most probable hydrocarbon flow path exists in the production casing annulus. Only a single hydrostatic barrier exist preventing hydrocarbon migration to the aquifer.
Figure 7.11  Wellbore diagram of a category 2 wellbore barrier design in the San Juan Basin, Colorado.

Category 3 well barrier designs have shallow surface casing and the TOC of production cement above the top of gas (Figure 7.12). Only thirteen wells existed with this original design and they had an average completion date of 1977. The most probable hydrocarbon migration flow path exists in the production casing. These barrier designs have two barriers preventing hydrocarbon migration: production casing and annular hydrostatic pressure.
Category 4 well barrier designs have shallow surface casing and the top of production cement above the surface casing shoe (Figure 7.13). Seventy-one wells existed with this original design and they had an average completion date of 1980. This design is similar to category 3 wells, with the most probable hydrocarbon migration flow...
path in the production casing. These wells have two barriers: production casing and production cement.

Figure 7.13 Wellbore diagram of a category 4 wellbore barrier design in the San Juan Basin, Colorado.

Moderate risk wellbore barrier designs include categories 5 – 6. These barrier designs all have deep surface casing in relation to the depths of water wells within a
0.5-mile radius of an oil and gas well or deeper than 169 ft for oil and gas wells that are not within a 0.5-mile radius of a water well.

Category 5 well barrier designs have deep surface casing and the TOC of the production cement below the top of gas (Figure 7.14). These wells generally target deeper hydrocarbon zones from the Dakota Group, Mancos Shale, Cliff House Formation or Mesaverde Group. Fifty-four wells existed with this original design and they had an average completion date of 1987. The most likely migration flow path exists in the production casing annulus. Three barriers are present to prevent hydrocarbon migration: annular hydrostatic pressure, surface casing and surface cement.

Figure 7.14 Wellbore diagram of a category 5 wellbore barrier design in the San Juan Basin, Colorado.
Category 6 well barrier designs have deep surface casing and the TOC of production cement above the top of gas (Figure 7.15). 348 wells existed with this original design and they had an average completion date of 1989. The most probable migration flow path is in the production casing. These wells have three barriers preventing hydrocarbon migration: production casing, surface casing and surface cement.

Figure 7.15 Wellbore diagram of a category 6 wellbore barrier design in the San Juan Basin, Colorado.
A lower risk dual casing string wellbore barrier design is category 7. This well barrier design has deep surface casing and the TOC of production cement above the surface casing shoe (Figure 7.16). This well design is the most common in the San Juan Basin, Colorado, and represents 70% of the originally completed wells in the data sample set. 2,677 wells existed with this original design and they had an average completion date of 1994. The most probable hydrocarbon migration flow path is in the production casing. These wells have four barriers: production casing, production cement, surface casing and surface cement.

Figure 7.16 Wellbore diagram of a category 7 wellbore barrier design in the San Juan Basin, Colorado.
Lower risk well barrier designs include an additional intermediate casing string. These three string casing designs include categories 8 – 12. Category 8 well barrier designs have deep surface casing, deep intermediate casing with the TOC of intermediate cement above the surface casing shoe and the TOC of production casing cement below the top of gas (Figure 7.17). Sixty-four wells existed with this original design and they had an average completion date of 1984. The most probable hydrocarbon migration flow path is in the production casing annulus for these wells. This well design has five barriers: hydrostatic annular pressure, intermediate casing, intermediate cement, surface casing and surface cement.

Figure 7.17  Wellbore diagram of a category 8 wellbore barrier design in the San Juan Basin, Colorado.
Category 9 well barrier designs have shallow surface casing, an intermediate casing string with the TOC of intermediate cement above the surface casing shoe and the TOC of production casing cement above the intermediate casing shoe (Figure 7.18). Seventeen wells existed with this original design and they had an average completion date of 1981. The most probable hydrocarbon migration flow path is in the production casing. These wells have four barriers: production casing, production cement, intermediate casing, and intermediate cement.

![Figure 7.18 Wellbore diagram of a category 9 wellbore barrier design in the San Juan Basin, Colorado.](image-url)

140
Category 10 well barrier designs have deep surface casing, an intermediate casing string with the TOC of intermediate cement above the top of gas, and the TOC of production cement above the top of gas (Figure 7.19). 148 wells existed with this original design and they had an average completion date of 1974. The most probable hydrocarbon migration flow path is in the production casing for this design. These wells have six barriers to prevent hydrocarbon migration: production casing, annular hydrostatic pressure, intermediate casing, intermediate cement, surface casing and surface cement.

Figure 7.19 Wellbore diagram of a category 10 wellbore barrier design in the San Juan Basin, Colorado.
Category 11 well barrier designs have deep surface casing, an intermediate casing string with the TOC of intermediate cement above the top of gas, and the TOC of production cement above the top of the intermediate casing shoe (Figure 7.20). 427 wells existed with this original design and they had an average completion date of 1977. The most probable hydrocarbon migration flow path is in the production casing for this design. These wells have six barriers to prevent hydrocarbon migration: production casing, production cement, intermediate casing, intermediate cement, surface casing and surface cement.

Figure 7.20  Wellbore diagram of a category 11 wellbore barrier design in the San Juan Basin, Colorado.
7.7 San Juan Basin Potential Barrier Failures

Potential barrier failures in the San Juan Basin were identified by any remedial cement work performed on any casing string. 3.32%, or 127 of 3,831 originally producing wells, were identified as potential barrier failures (Table 7.2). This lower potential barrier failure rate, compared with the three previous basins or fields under this study, was a result of the predominantly more robust barrier designs implemented in the basin throughout its development.

Table 7.2 Potential barrier failures in the San Juan Basin, Colorado

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>WELL COUNT</th>
<th>POTENTIAL BARRIER FAILURES</th>
<th>POTENTIAL BARRIER FAILURE %</th>
<th>ORIGINAL AVG AGE OF WELL</th>
<th>P&amp;A WELL COUNT</th>
<th>CURRENT WELL COUNT</th>
<th>ORIGINAL AVG SURFACE DEPTH (FT)</th>
<th>ORIGINAL AVG INT 1 TOP OF CEMENT (FT)</th>
<th>ORIGINAL AVG INT 1 DEPTH (FT)</th>
<th>ORIGINAL AVG TOP OF PRODUCTION CEMENT (FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>12</td>
<td>0</td>
<td>0.00%</td>
<td>1978</td>
<td>6</td>
<td>6</td>
<td>88</td>
<td>1,900</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>13</td>
<td>0</td>
<td>0.00%</td>
<td>1977</td>
<td>9</td>
<td>4</td>
<td>118</td>
<td>2,471</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>71</td>
<td>0</td>
<td>0.00%</td>
<td>1980</td>
<td>17</td>
<td>54</td>
<td>110</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>54</td>
<td>30</td>
<td>55.56%</td>
<td>1987</td>
<td>18</td>
<td>11</td>
<td>1021</td>
<td>3,578</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>348</td>
<td>84</td>
<td>24.14%</td>
<td>1989</td>
<td>74</td>
<td>201</td>
<td>633</td>
<td>1,575</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>2,677</td>
<td>4</td>
<td>0.15%</td>
<td>1994</td>
<td>172</td>
<td>2,603</td>
<td>414</td>
<td>18</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>64</td>
<td>5</td>
<td>7.81%</td>
<td>1984</td>
<td>9</td>
<td>51</td>
<td>395</td>
<td>3774</td>
<td>235</td>
<td>6,762</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>17</td>
<td>0</td>
<td>0.00%</td>
<td>1981</td>
<td>5</td>
<td>12</td>
<td>120</td>
<td>1443</td>
<td>118</td>
<td>723</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>148</td>
<td>4</td>
<td>2.70%</td>
<td>1974</td>
<td>18</td>
<td>127</td>
<td>362</td>
<td>3266</td>
<td>800</td>
<td>4,137</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>427</td>
<td>0</td>
<td>0.00%</td>
<td>1977</td>
<td>59</td>
<td>375</td>
<td>326</td>
<td>3230</td>
<td>367</td>
<td>1,033</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,831</td>
<td>127</td>
<td>3.32%</td>
<td></td>
<td>387</td>
<td>3,444</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D&amp;A</td>
<td>358</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL WELL COUNT</td>
<td>4,189</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Category 5 well barrier designs had a 55.56% potential failure rate due to its top of production cement below the top of gas. Category 6 well barrier designs had the second highest potential barrier failure rate of 24.14%. This well design had deep surface casing and the top of production cement above the top of gas. The higher potential failure rate could be caused by challenges in effectively creating a cement seal in the production casing annulus due to shallow geologic conditions. Category 7 well barrier designs, which represent 70% of the original wells in the basin, had a relatively low potential barrier failure rate of 0.15%. This well barrier design is low risk with four independent barriers preventing hydrocarbon migration: production casing, production cement, surface casing and surface cement.

Categories 2 – 4 represent higher risk well barrier designs. However, no potential barrier failures were found on these designs. Potential barrier failures were
distributed across the area of dense oil and gas development and no noticeable patterns exist related to the spatial distribution (Figure 7.21). 54% of all potential barrier failures occurred on wells that were originally completed between 1999 and 2004 (Figure 7.22).

Figure 7.21 Map of potential barrier failures color coded by their original wellbore barrier category with locations and depths of water wells in the San Juan Basin, Colorado.

Gas produced from the Fruitland Coal is considered dry, with a mole fraction of methane of 93.855% (Figure 7.23). Low average CO$_2$ mole fractions of 0.012% from these CBM wells, reduce the risk of corrosion of the carbon-steel casing. The low potential barrier failure rate is a combination of more robust barrier designs in the basin and the low percentage of corrosive gas in the produced gas stream from CBM wells targeting the Fruitland Coal.
Figure 7.22  Histogram of potential barrier failures color coded by their original wellbore barrier category in the San Juan Basin, Colorado.
7.8 San Juan Basin Catastrophic Barrier Failure Overview

Catastrophic barrier failure is the breakdown of the combination of various wellbore barriers (casing, cement and hydrostatic pressure of annular fluids) protecting fresh water aquifers during stimulation and production operations resulting in the contamination of the aquifers. Contamination can be characterized by comparing the surrounding water well chemistry to the produced fluids of adjacent oil and gas wells through analytic and isotopic analysis. Wells in the field that were eventually turned to production are commonly artificially stimulated with some form of hydraulic fracturing technology. Typical hydraulic fracturing treatments designs in the field utilize fresh water, gelling agents, nitrogen, various fluid additives and silica sand proppant. No evidence was found in this study that hydraulic fracturing operations directly contaminated fresh water aquifers in the San Juan Basin, Colorado. All catastrophic
Two catastrophic barrier failures related to hydrocarbon migration to fresh water aquifers or surface soil were identified out of 3,831 originally producing oil and gas wells in the San Juan Basin, Colorado (Table 7.3). The catastrophic barrier failure rate of 0.05% in the San Juan Basin, is lower than the findings for the Wattenberg Field, the Piceance Basin (Garfield County, Colorado), and the Raton Basin, Colorado. The most common well barrier designs in the San Juan Basin are lower risk nested barrier designs with deep surface casing. These designs were implemented due to the basin’s geology containing shallow coal deposits in the Fruitland Formation or structurally shallower depths of the lower Dakota Group, Mancos Shale, Pictured Cliffs and Mesaverde Groups near the New Mexico border.

Table 7.3 Catastrophic barrier failures in the San Juan Basin, Colorado

<table>
<thead>
<tr>
<th>SAN JUAN BASIN WELLS</th>
<th>ORIGINAL WELL COUNT</th>
<th>CATASTROPHIC BARRIER FAILURES</th>
<th>CATASTROPHIC BARRIER FAILURE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CATEGORY 1</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 2</td>
<td>12</td>
<td>1</td>
<td>8.33%</td>
</tr>
<tr>
<td>CATEGORY 3</td>
<td>13</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 4</td>
<td>71</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 5</td>
<td>54</td>
<td>1</td>
<td>1.85%</td>
</tr>
<tr>
<td>CATEGORY 6</td>
<td>348</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 7</td>
<td>2,677</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 8</td>
<td>64</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 9</td>
<td>17</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 10</td>
<td>148</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 11</td>
<td>427</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>CATEGORY 12</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3,831</td>
<td>2</td>
<td>0.05%</td>
</tr>
</tbody>
</table>

Both catastrophic barrier failures were drilled prior to 1961. The category 2 well that experienced a catastrophic failure was improperly plugged and abandoned in the
1960s and had evidence of thermogenic gas leaking to the surface from the existing wellbore. The category 5 well had improper cement coverage in the annulus of the intermediate casing, which acted as a conduit for thermogenic gas migration to the fresh water aquifer. A water well that was 1,129 feet radial distance away from the surface location of the well detected thermogenic gas which was tested and confirmed to be directly from the oil and gas well that experienced a catastrophic barrier failure (Figure 7.24).

Figure 7.24 Map of catastrophic barrier failures with locations and depths of water wells in the San Juan Basin, Colorado.

7.9 San Juan Basin Catastrophic Barrier Failures

On February 12, 2005, a double wide trailer exploded and a resident sustained burns and was transported to a hospital in Denver. The site of the explosion was near an old plugged and abandoned well 05-067-05211. This well was drilled in 1938 as an original category 2 well barrier design and later plugged and abandoned in 1966. The original well design had shallow surface casing and an un-cemented production casing
string set at 2,240 feet subsurface. Records indicate that the well was improperly plugged and abandoned and gas was flared from the surface marker of the original wellbore in the 1960s. In 1994, the COGCC voluntarily re-plugged the wellbore. Isotopic and compositional analysis of from the surface soil, near the site of the explosion was indicative of the Fruitland Formation. Since this oil and gas well was an orphaned wellbore, the COGCC didn’t issue violations to a specific operator but determined that the oil and gas well was the source of the thermogenic gas migration to surface. In 2009, the COGCC issued rule 608 for Coalbed Methane development to prevent instances of improper plugging and abandonment of orphaned oil and gas wells. Additionally, the COGCC set aside funding for reclamation of the surrounding area and terminate the leak source from the 05-067-05211 well.

Well 05-007-05004 was drilled in 1961 with an original category 5 well barrier design. This well had shallow surface casing set at 205 ft, an intermediate casing set at 3,507 ft and a top of intermediate cement of 2,705 ft and a cemented production liner extending from the base of the intermediate casing shoe. A water well, 1,129 ft from the 05-007-05004 well, detected thermogenic gas based on isotopic and compositional analysis in 2002. The source of the thermogenic gas was determined to be from the 05-007-05004 well’s intermediate casing annulus, due to improper cement coverage of the Fruitland Formation behind the intermediate casing string. The COGCC issued a violation to the operator for violating rule 317i, for inadequate cement behind the casing of the well to protect fresh water aquifers. The 05-007-05004 well was subsequently plugged and abandoned in 2008.

Two of 3,831 originally producing oil and gas wells experienced a catastrophic barrier failure related to hydrocarbon migration to fresh water aquifers of surface soil in the San Juan Basin, Colorado. The catastrophic barrier failure rate of 0.052% is the lowest of all the basins under investigation. It was observed that catastrophic barrier failures occurred on one high risk wellbore barrier design due to improperly plugging abandoning its wellbore and one moderate risk wellbore barrier design due to ineffective cement isolation of hydrocarbon zones in the intermediate casing annulus. Similar to the Raton Basin, complications exist with locating orphaned plugged and abandoned wells and assuring the quality of the plugging in the basin.
The lower catastrophic barrier failure rate in the basin is due to the 97.49% of wells with deep surface casing, an effective geologic barrier, the Kirtland Shale, separating deeper hydrocarbon bearing formations from surface aquifers and lower molecular percentages of corrosive gas in the produced gas stream. No evidence of fracturing fluid migration to fresh water aquifers was detected in the dataset for the San Juan Basin, Colorado.

7.10 San Juan Basin Existing Conditions

64 of 3,444 existing wells that are currently producing or shut-in in the San Juan Basin have shallow surface casing. This represents 2.21% of the existing producing or shut-in wells in the basin. There are ten higher risk category 2 and 3 wells remaining in the field (Figure 7.25). Two category 3 wells are within close proximity of water wells and the remaining eight wells are in rural areas devoid of water wells according to data acquired from the COGCC water well database.

Figure 7.25 Map of existing higher risk wellbore barrier designs with shallow surface casing and locations and depths of water wells in the San Juan Basin, Colorado.
Overall, the San Juan Basin, Colorado wells are designed with lower risk well barrier designs. 98.1% of the existing producing or shut-in wells in the field have deep surface casing or deep intermediate casing (Figure 7.26). Due to shallow hydrocarbon deposits, wells have been designed with lower risk well barrier designs throughout the development of the basin.

Figure 7.26 Map of existing wells color coded by their current wellbore barrier categories in the San Juan Basin, Colorado.
CHAPTER 8
CONCLUSIONS

1. No evidence of fresh water aquifer or surface soil contamination by hydraulic fracturing operations through wellbores was discovered in all four basins under investigation in the State of Colorado.

2. No catastrophic barrier failures were detected for all horizontal wells nor any wells with intermediate casing.

3. A total of 24 of the 35,833 originally producing vertical wells (0.067%) in the four basins exhibited signs of hydrocarbon migration to fresh water aquifers or surface soil through a complete barrier failure of the wellbore (Table 8.1). This low statistical number of system failures is due to the redundancy of multiple, independent, barriers to migration.

Table 8.1 Summary of catastrophic barrier failures related to hydrocarbon migration to surface soil or fresh water aquifers in the State of Colorado

<table>
<thead>
<tr>
<th>BASIN/FIELD</th>
<th>ORIGINAL PRODUCING WELL COUNT</th>
<th>EXISTING WELLS</th>
<th>CATASTROPHIC BARRIER FAILURES RELATED TO THERMOGENIC GAS MIGRATION</th>
<th>CATASTROPHIC BARRIER FAILURE RATE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>WATTENBERG FIELD</td>
<td>17,801</td>
<td>16,693</td>
<td>10</td>
<td>0.056%</td>
</tr>
<tr>
<td>PICEANCE BASIN - GARFIELD COUNTY, COLORADO</td>
<td>10,842</td>
<td>10,507</td>
<td>9</td>
<td>0.083%</td>
</tr>
<tr>
<td>RATON BASIN - COLORADO</td>
<td>3,359</td>
<td>3,007</td>
<td>3</td>
<td>0.089%</td>
</tr>
<tr>
<td>SAN JUAN BASIN - COLORADO</td>
<td>3,831</td>
<td>3,448</td>
<td>2</td>
<td>0.052%</td>
</tr>
<tr>
<td>TOTAL PRODUCING WELLS</td>
<td>35,833</td>
<td>33,655</td>
<td>24</td>
<td>0.067%</td>
</tr>
</tbody>
</table>

4. 90% of the catastrophic barrier failures in the Wattenberg Field had commonality of shallow surface casing and the TOC of production cement below the top of gas (Sussex Formation) (Table 8.2). One catastrophic barrier failure had deep surface casing but didn’t exhibit signs of contamination of the aquifer system, but had elevated benzene levels detected at surface.
5. 78% of the catastrophic barrier failures in the Piceance Basin, Garfield County, had deep surface casing and the TOC of production cement above the top of gas (Williams Fork Formation) (Table 8.2). This validates the presence of hydrocarbons in the Wasatch Group at shallow depths. In addition, high corrosion rates are experienced in the field that can lead to elevated barrier failure rates of the production casing.

6. Two of three catastrophic barrier failures in the Raton Basin were related to improperly plugging and abandoning old wellbores. One catastrophic barrier failure had deep surface casing and the TOC of production cement above the surface casing shoe and still experienced SAP prior to the hydrocarbon migration discovery at surface. This well was in close proximity of one of the catastrophic barrier failures that was plugged and abandoned. This area of the basin was under investigation by the COGCC for natural hydrocarbon seeps near the town of Walsenburg in proximity of abandoned coal mines.

7. One of two catastrophic barrier failures in the San Juan Basin was due to improperly plugging and abandoning an old wellbore. However, both original wellbores had commonality with the TOC of production cement below the top of gas (Fruitland Formation).

8. The higher catastrophic barrier failure rates in the Raton and Piceance Basins are related to the shallow presence of hydrocarbons within these basins and an insufficient geologic barrier separating the aquifer systems from hydrocarbon bearing formations below. In addition, water wells are commonly drilled into shallow formations which naturally contain hydrocarbons, the Raton Formation and the Wasatch Group.

9. A total of 1,285 of the 35,833 originally producing wells (3.586%) in the four basins under investigation had a potential barrier failure without hydrocarbon migration to fresh water aquifers or surface soil (Table 8.3).

10. The Raton Basin had the highest potential barrier failure rate (10.807%). This could be more related to COGCC rule 303F, which stipulates that the TOC of the production cement must be above the previous casing shoe in the Raton Basin and not necessarily due to the observance of SAP.
Table 8.2 Percentage of catastrophic barrier failures by basin that are related to casing setting depths and production cement tops

<table>
<thead>
<tr>
<th>BASIN/FIELD</th>
<th>SHALLOW SURFACE CASING</th>
<th>DEEP SURFACE CASING</th>
<th>PRODUCTION TOC BELOW TOP OF GAS</th>
<th>PRODUCTION TOC ABOVE TOP OF GAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>WATENBERG FIELD</td>
<td>90%</td>
<td>10%</td>
<td>90%</td>
<td>10%</td>
</tr>
<tr>
<td>PICEANCE BASIN - GARFIELD COUNTY, COLORADO</td>
<td>22%</td>
<td>78%</td>
<td>22%</td>
<td>78%</td>
</tr>
<tr>
<td>RATON BASIN - COLORADO</td>
<td>33%</td>
<td>67%</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>SAN JUAN BASIN - COLORADO</td>
<td>50%</td>
<td>50%</td>
<td>100%</td>
<td>0%</td>
</tr>
</tbody>
</table>

Table 8.3 Summary of potential barrier failures without hydrocarbon migration to surface soil or fresh water aquifers in the State of Colorado

<table>
<thead>
<tr>
<th>BASIN/FIELD</th>
<th>ORIGINAL PRODUCING WELL COUNT</th>
<th>EXISTING WELLS</th>
<th>POTENTIAL BARRIER FAILURES</th>
<th>POTENTIAL BARRIER FAILURE RATE %</th>
</tr>
</thead>
<tbody>
<tr>
<td>WATENBERG FIELD</td>
<td>17,801</td>
<td>16,693</td>
<td>418</td>
<td>2.348%</td>
</tr>
<tr>
<td>PICEANCE BASIN - GARFIELD COUNTY, COLORADO</td>
<td>10,842</td>
<td>10,507</td>
<td>377</td>
<td>3.477%</td>
</tr>
<tr>
<td>RATON BASIN - COLORADO</td>
<td>3,359</td>
<td>3,007</td>
<td>363</td>
<td>10.807%</td>
</tr>
<tr>
<td>SAN JUAN BASIN - COLORADO</td>
<td>3,831</td>
<td>3,448</td>
<td>127</td>
<td>3.315%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>35,833</td>
<td>33,655</td>
<td>1,285</td>
<td>3.586%</td>
</tr>
</tbody>
</table>

11. 80% of the potential barrier failures in the Wattenberg Field had shallow surface casing and 95% had the TOC of production cement below the top of gas. The low percentage of potential barrier failures for wells with deep surface casing and the TOC of production cement above the top of gas validates the effectiveness of more robust nested barrier designs in the field and demonstrates the strength of the geologic barrier (Pierre Shale) separating the aquifer system from hydrocarbon deposits below.

12. Potential barrier failures were common in wells that had deep surface casing and the TOC of production cement above the designated top of gas in the Piceance Basin and San Juan Basin. Both basins have challenges in effectively creating a cement seal in the production casing annulus due to shallow geologic conditions.
13. 89% of the potential barrier failures in the Raton Basin had the TOC of production cement below the top of gas (Raton Formation). 99% of the potential barrier failures had deep surface casing. Although, these potential barrier failures could be more correlated to rule 303F in the Raton Basin.

Table 8.4 Percentage of potential barrier failures by basin that are related to casing setting depths and production cement tops

<table>
<thead>
<tr>
<th>BASIN/FIELD</th>
<th>SHALLOW SURFACE CASING</th>
<th>DEEP SURFACE CASING</th>
<th>PRODUCTION TOC BELOW TOP OF GAS</th>
<th>PRODUCTION TOC ABOVE TOP OF GAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>WATTENBERG FIELD</td>
<td>80%</td>
<td>20%</td>
<td>95%</td>
<td>5%</td>
</tr>
<tr>
<td>PICEANCE BASIN - GARFIELD COUNTY, COLORADO</td>
<td>7%</td>
<td>93%</td>
<td>39%</td>
<td>61%</td>
</tr>
<tr>
<td>RATON BASIN - COLORADO</td>
<td>1%</td>
<td>99%</td>
<td>89%</td>
<td>11%</td>
</tr>
<tr>
<td>SAN JUAN BASIN - COLORADO</td>
<td>0%</td>
<td>100%</td>
<td>24%</td>
<td>76%</td>
</tr>
</tbody>
</table>

14. Migration of hydrocarbons into fresh water aquifers or surface soil was found to be associated with wells completed prior to 1961 in the San Juan Basin, Colorado, 1992 in the Wattenberg Field, 2004 in the Piceance Basin, Garfield County, and 2005 in the Raton Basin, Colorado.

15. The higher risk of hydrocarbon migration related to complete wellbore barrier system failures correlated to the older age of the wells in the Wattenberg Field and the San Juan Basin. These older wells had less robust construction designs; the barriers preventing migration were not as redundant compared to more recently completed wells. However, catastrophic barrier failures were common for more recently completed wells in the Piceance Basin and Raton Basin due to the shallow presence of hydrocarbons in the Wasatch Group and Raton Formation, respectively.

16. The risk of barrier failure of one or more barriers in all wells without hydrocarbon migration was determined to be 3.586% or one in 28 wells in the State of Colorado.

17. The risk of hydrocarbon migration due to one or more barrier failures in all wells was determined to be 0.067% or one in 1,493 wells in the State of Colorado.
8.1 Further Research Recommendations

The assessment of risk of hydrocarbon or fracturing fluid migration to fresh water aquifers or surface soil can be applied to any state that has oil and gas development. This assessment is a snapshot in time and represents what has occurred prior to 2014 in the State of Colorado. As more oil and gas wells are drilled, the assessment can be taken further.

Due to the complete quality of data from the state database, it is recommended that operators supply more precise cement and casing data in order to ascertain the true wellbore barrier categories for each individual well and reasons for cement remediation. However, challenges exist with obtaining accurate data from older inherited wells by current operators due to lack of comprehensive drilling and completion reports from the original operators.

Additionally, probabilities of individual barrier failures can be estimated based on the statistical data presented. However, under the current state of the data analysis, it is challenging to estimate individual barrier failure probabilities without making broad assumptions.
REFERENCES


URS. 2006. Phase I Hydrogeologic Characterization of the Mamm Creek Field Area in Garfield County., URS Corporation, Denver, Colorado.


