Fracking, Photons, and the Grid: The future of Energy Production in Montana

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Forward

At the core of every process in the world is energy. The extraction, transfer, and consumption of energy are essential tasks that all life forms carry out in some form or another. Often the energy needs of a species are limited to that which is necessary to sustain life. However, humans have developed a much larger energy demand to support a technologically advanced way of life. As a global society the human race has become reliant on fossil fuels as our main energy source. From heating homes and powering vehicles, to making plastics and the ink on this paper, fossil fuels are the cornerstone on which modern day civilization is built.

Prior to any of our modern amenities becoming a reality, fossil fuels must be extracted from the ground and processed. This is where energy becomes a relevant topic for Montana residents, where horizontal drilling and hydraulic fracturing has given us access to a rich supply of gas and oil reserves. As with any industrial process, hydraulic fracturing has its pros and cons, all of which must be weighed and considered carefully. A portion of this paper will objectively do just that, particularly surrounding environmental implications. Over the centuries the focus and form of fossil fuel use has changed, but there are two main things that have not changed: 1) fossil fuels are consumed at a rate that is exponentially greater than the rate they are created, and 2) the consumption of fossil fuels adversely affects the global environment.

The former of these facts was first predicted in 1956 by Dr. M.K. Hubbert, a geoscientist working for the Shell Oil Company (hubbertpeak.com/hubbert/). Dr. Hubbert realized that while oil was an energy source that seemed to be in endless abundance, it must be a finite resource that would eventually be depleted. This "Hubbert Peak Theory" was made at a time when new oil discoveries were being made every day, and no one in the oil-production world took him seriously. Things changed drastically during the oil crisis of the 1970's, when it became apparent that Dr. Hubbert's model for peak oil production was plausibly correct. Dr. Hubbert eventually became a senior research geophysicist for the U.S. Geological Survey, where he continued to be a visionary of the energy industry. In 1975, Dr. Hubbert concluded that solar power and other renewable resources would be the way of the future. He wasn't wrong.

A steadily growing movement in the energy world is the use of renewable energy sources. A renewable energy source is 'any naturally occurring, theoretically inexhaustible source of energy' (dictionary.com). All of the renewable energies listed above are ultimately solar energies. Plant biomass is produced as a result of photosynthesis using sunlight. Tidal patterns and waves form as a result of the gravitational effect of the sun and the moon in conjunction with warming by the sun. Wind, weather, and the entire hydrologic cycle are fueled by the energy of sunlight. Another energy source that is considered renewable is geothermal energy, which is arguably a solar energy and harnesses the warmth of the earth's core. As long as there is a sun shining on Earth, there will be energy sources.

The challenge being faced today is weaning a fossil fuel society off of the use of non-renewable resources, a feat that can be made easier by making the feasibility of renewable energy sources more widely known. This is an initiative that, if embraced now, could lead to a major paradigm shift in the way the next generation thinks about energy sources. In addition to highlighting a way ahead with renewable energy sources, it is equally important to look at the impact that the current use of non-renewable energy resources is having, particularly from hydraulic fracturing in Montana. With an environmentally conscious approach, the objective of this paper is to make an informative analysis of the social and environmental impacts surrounding hydraulic fracturing, the challenges of site remediation, alternative energy options using renewable sources, and the implications incurred by renewable energy sources. Through the tool of information, this review will hopefully serve to make Montanans more energy conscientious, and help prevent energy visionaries like Dr. Hubbert from not being heard until it's too late.

Hydraulic Fracturing

Oil and natural gas are important contributors to our world energy use. Over the past few years, new developments in the extraction process, along with clean, alternative energy options are transforming our energy profile.

Natural gas burns cleaner than any other fossil fuel but it is not cleaner in its extraction lifecycle (Lustgarten, 2012). The lifecycle costs of methane and carbon dioxide emission from development of unconventional sources such as shale, along with the volume of chemical waste in flowback and remnants of toxins deep within the earth after extraction, all represent a significant threat to our air, soil, and water quality.

Hydraulic fracturing, or "fracking", is a method to access oil and natural gas by creating fractures in deeper pockets of horizontally drilled wells, allowing for more production capacity by increasing a wells exposure to the geologic formation. Fracking was first used in the United States in 1947 and entered commercial use after 1949(Halliburton, 2012). Shale gas extraction has taken center stage within the past few years through the advances in new technologies by allowing us to both visualize these layers of methane rich shale with the aid of computer modeling in fracture design, and gain greater access by using horizontal drilling techniques with new rotary steerable tools that allow operators to drill with more accuracy (Hill, 2010). These new developments in extraction have allowed us to maximize the surface contact with horizontal shale or "tight gas" formations, essentially catapulting us into this Gas Rush.

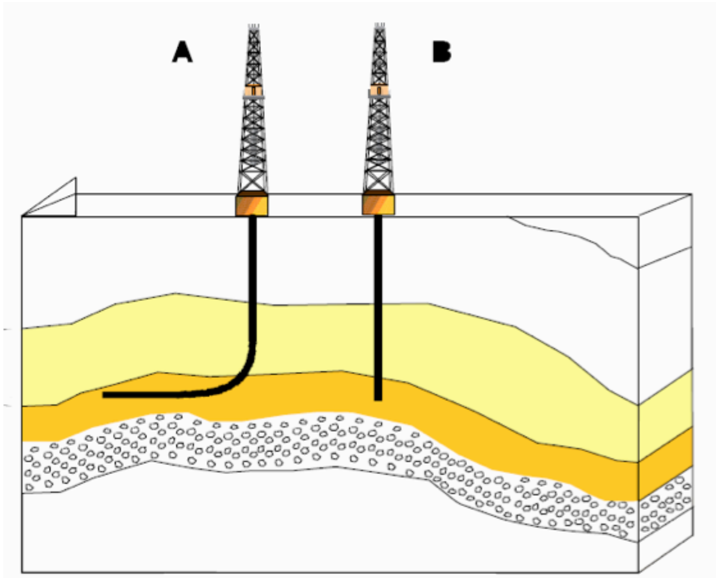


Figure 0: Schematic of a horizontal (A) and a vertical (B) well. Image: http://www.popularmechanics.com/science/energy/coal-oil-gas/4318390

With onshore methods of extracting oil and natural gas, a distinction can be made between the drilling stage and the fracking stage at a well site. Vertical drill depths lie anywhere between 1000-8000 feet deep, and in combination with horizontal drilling, wells can reach thousands of feet away from the surface production pad (EPA, 2010). Horizontal wells give rise to maximum exposure within a formation, compared to conventional vertical wells (Figure 1).

Many potential shale formations overlie developed conventional gas reserves, leading to easier access of core sampling and shale tapping potential. Although, with shale gas deposits spread over much wider areas than conventional reserves, and the overall shorter lifespans of these tight shale wellbores, more wells will need to be drilled (IEA, 2009). Successful wells must produce a large amount of gas resources in order to justify expense, time, and effort associated with the drilling, fracking, and maintenance of these wells.

How Does Fracking Work?

Once the well site permits have been obtained, and the site cleared, the drilling process commences. The well is first drilled down past the aquifer layer, where it is then cased with steel and cement grout to minimize potential for damaging groundwater resources. Technological advances allow operators to use angle building processes through precise control of a drill bit to extend a well horizontally, providing greater access to gas bearing layers. Casing the well with cement permanently secures the well bore, and prevents hydrocarbons and other fluids from seeping out of the formations. A single drilling pad can play host to several horizontal wells (or legs), oriented in different directions. This drilling process can take up to a month.

The next process is the fracturing itself, which is controlled mainly by reservoir and rock parameters. A 'perf-gun' is lowered into the bore, and is used to perforate the casing by sending an electrical current that shoots holes through the cement and into the shale formation. To open the cracks to more efficiently extract oil and gas, a mixture of water, sand, and chemicals is injected at high pressure, causing the shale formation to fracture. The fracturing fluid is then drained, and proppants, usually sand or ceramic beads, are left behind to hold open the fissures in the formation during the pressure release (Fig 2). The type of well bore used will affect how many times and at what location the formation is fractured. Sequential fracturing occurs when frac plugs close off the first stage of extraction, and the process is repeated in the adjacent section, down the entire length of the well bore. The individual processes of fracking and plugging in a horizontal bore can total 40-60 individual stages (Meek, 2012).

Once the fracturing fluid, or flowback has been returned to the production pad, the extraction process begins as natural gas flows out from these fissures and is collected at the surface. The yield during the first month of a well's operation will reveal how valuable that well will be over time. Furthermore, it is common to see a sharper peak of gas production (during the first two years of a well's production) followed by a rapid decline, thus leading to a shorter overall lifespan for a wells recovery with new shale and tight gas extraction methods (King, 2012).

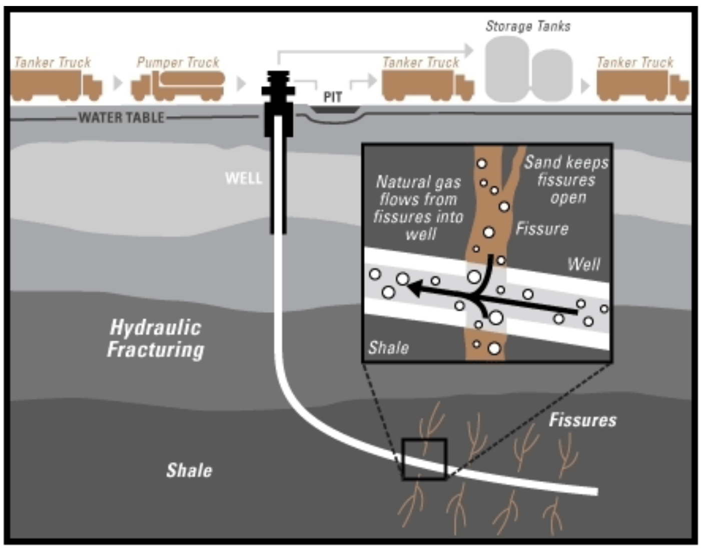


Figure 1. Hydraulically fracked shale formation. (http://legalplanet.wordpress.com/2012/09/13/golden-rules-for-fracking/, Sept 13 2012)

With the lure of a new domestic energy source and the promise of jobs in regions starved of investment, many of the potential risks are being swept aside as large-scale extraction expands to new areas around the country. There is increasing concern about the amount of water used during fracking, the gas migration and groundwater contamination risks due to faulty well construction or blowouts, the hazards in transporting and storing toxic chemicals, and the risks associated with damaging critical infrastructure. In addition to the certainty of playing these high stakes in unlocking vast stores of natural gas, there are many unknowns associated with long-term impacts. Do the costs of: high water use, thousands of acres of site clearing, new road networks fragmenting habitat, increasing traffic/noise with construction and fracking equipment, along with the inherent risks for potential catastrophic contamination of our resources, all balance out in the end? With this explosion in exploration of the gas sector, the issue remains on how to best regulate and monitor these sites in order to minimize these high consequence risks.

The Water Resource

With the rising use of hydraulic fracturing technology to produce oil and natural gas, there are growing concerns about environmental impacts, in particular the potential for fracking to affect water quality and water usage. The amount of water necessary for each individual well, can be anywhere between 2 to 9 million gallons, with each well site having the ability to support up to twenty individual well bores (Keer, 2012).

The concerns are shared among a diverse set of stakeholders, such as farmers, local residents, environmentalists, and governmental or non-governmental organizations; each posing a common set of questions including: how much water is being used? whose water is being used? Where is this water coming from? And, what are the implications of the water use with respect to my surroundings and livelihood? The regularity of these questions is often magnified with respect to experiences concerning pre-existing water scarcities and respective beliefs surrounding water rights, and concerns surrounding environmental issues when important natural resources are potentially threatened. There are concerns that the water used for the hydraulic fracturing process could lead to depleted water resources throughout communities that rely on this water for agriculture or urban needs, and also that the water use may lead to the inadequate regeneration of natural water sources such as groundwater aquifers, lakes and streams. Changes in water use relevant to hydraulic fracturing will be examined in this paper, through both a direct sense towards water use for the fracturing process onsite, and briefly on indirect use, with respect to water needs for local infrastructure development or the needs for supplying water to workers.

Onsite water use: The fracturing fluid and Sources of water

Water usage estimates for a hydraulic fracturing well operation are on average around 2 to 9 million gallons [P4], however, this figure varies with well location, the local geology, the fracturing fluids being used, and the size and type of well (EPA, 2011; API, 2010). The sources of this water include groundwater, surface water, municipal water supplies, and recycled fluids (flowback) from previous hydraulic fractures. (EPA, 2011; API, 2010; Arthur et al. 2010). Water use from shale gas development, which includes the process of hydraulic fracturing accounts for less than 1% of water use when considering agriculture, livestock raising, industrial use, and public water use activities (MIT, 2011).

Offsite Water Use

Offsite water usage includes changes in local infrastructure within townships and worker camps as the result of population increases through energy extraction jobs and other professions needed to support the employee population (food service, police enforcement etc.). These local population increases raise water consumption through individual and commercial needs. The increase in water consumption could put a strain on municipal water supplies and the respective sources from which that water is taken (surface, ground, etc.). The overall influence of offsite water use is hard to quantify due to differences in the localities of the working environments and respectively the relevant variation in water resource pressures as the result of changing populations.

Water Contamination & Chemical Usage

The potential for chemicals used in fracturing fluids to contaminate water resources, is a current and significant water quality issue (EPA, 2011). The State of Montana, and some other states, requires disclosure of the chemical content of fracking fluids, with exceptions for trade secret protection. This information, if properly understood, has the potential to inform the public discussion of fracking.

THE FRACK FLUID

On average, the fracturing fluids injected into the ground contain 90% water, 9.5% sand, and 0.5% chemical additives (Fig. 3). A survey of fourteen oil and gas companies revealed that 2,500 products containing up to 750 different chemicals were used between 2005 to 2009 to aid in the fracturing process (United States House of Representatives Committee on Energy and Commerce Minority Staff, 2011). There are potential public health effects because of the chemical usage. But, some chemicals are not hazardous, whereas others may have direct risks to public health (United States House of Representatives Committee on Energy and Commerce Minority Staff, 2011).

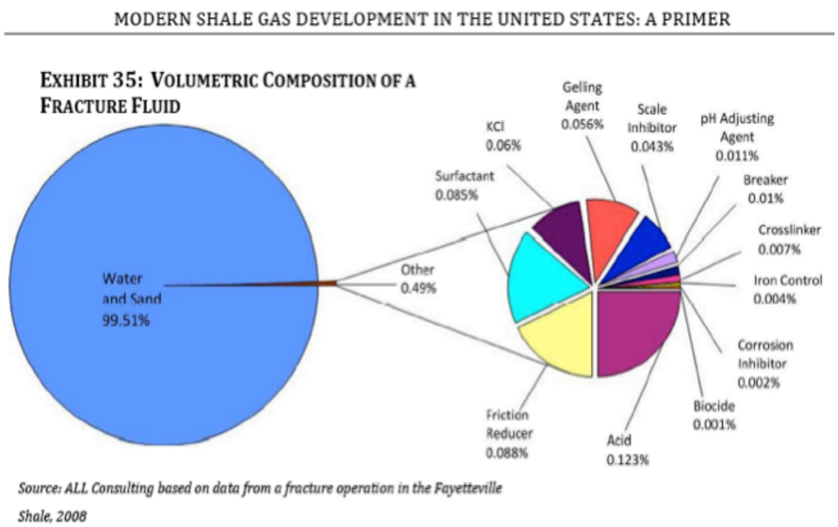


Figure 3. Diagram representing the composition of the hydraulic fracturing fluids. Source: http://www.libous.campaignoffice.com/vertical/Sites/{7FEEB937-AACE-4B99-9AAE-A9445EABBCBC}/uploads/fracking-fluid-composition.png

Chemicals are added to the fracking fluid to make the extraction process more efficient. There is extreme variability in the chemical composition of the frack fluid and different companies use different mixtures. The disparity can be attributed to variation in the geologic formations and company trade secrets. The additives are used belong to nine major functional groups: (1) the gelling agents (2) friction reducers, (3) biocides, (4) surfactants, (5) clay control, (6) scale inhibitors, (7) acids, (8) breakers, and (9) acid control inhibitors, and pH Control, and others (Colburn, 2010).

(1) The Gelling Agent

The gelling agent is used to make the water more viscous, to carry the proppant from the surface to the fissures without it settling out. The common chemicals used are “guar gum” and diesel. Guar gum is regularly used in processed foods like ice cream and salad dressing; it is also in toothpaste. Diesel is added to the mixture because guar gum reacts with diesel more effectively than water.

(2) The Friction Reducer
When water is pumped through the well bore piping, it interacts with walls of the pipe, slowing water flow in response to the high friction surface. With a friction reducer, water can flow with a higher velocity and more directly, allowing for a more forceful impact with the shale formations. The typical fracking fluid uses polyacrylamides as the friction reducing agent. Polyacrylamides are non-toxic and used to precipitate undesirable chemicals from drinking water at water treatment facilities and are also used in childrens’ toys because of their ability to absorb water.

(3) The Biocides
Microbes can use many chemicals in the fracking fluid as a growth medium and are capable of growing on the walls of the pipes. For example, microbes may “consume” polyacrylamides (Smith, *et al.*, 1996). By doing so, they change the chemical composition, potentially causing a neurotoxin “acrylamide” to form. For reasons like these, the fracking fluid uses biocides. Glutaraldehyde is one of the most common biocides used in the fracking process. It is used in the medical field to sterilize equipment and in hand soap as disinfectant.

(4) Surfactants
Surfactants decrease the surface tension of water by binding to the water molecules so that the frack fluid can flow through the pipes more easily in both directions (Colbon, 2010). Surfactants also have properties that suspend insoluble compounds in solution, making the extraction of the flowback more efficient (McCurdy, 2012). Surfactants are a detergent, so the surfactants used in fracking can also be found in household soaps.

(5) Clay Control
Shale is dominantly clay. When clay comes in contact with water, it absorbs more water than other mineral particles (i.e. sand or silt). When the water is sorbed to the clay the volume of the clay increases, causing it to “swell.” If the shale formation is hydraulically fractured, the clay particles may swell with the contact to such high volumes of water. Any swelling would cause the newly formed fractures to seal shut. Choline chloride is used to inhibit the swelling properties of clay (McCurdy, 2012). Choline chloride is an ingredient in most chicken feed.

(6) The Scale Inhibitor
The scale inhibitor keeps salts dissolved in the fracking fluid. As the chemicals interact with each other and with the geologic formation, salts precipitate, decreasing the functionality of the fracking fluid and leaving a residue. Chemicals like carboxylic or acrylic acid are used to keep the salts dissolved in solution (McCurdy, 2012). These chemicals are not likely to alter the pH of the buffered frack fluid given their low concentration in the total fluid. The way they react with other

molecules in the solution is, however, pH sensitive. This suggests that monitoring the presence pH of the frack fluid is important. Carboxylic acids are present in citric beverages, food preservatives, and vinegar.

(7) Acids
Similarly to the scale inhibitor, hydrochloric acid keeps acid-soluble contaminants that are present in the shale formation and in the pipes in solution. By keeping compounds in solution, there is less likelihood that the fractures will get clogged. This makes the extraction process and flow of natural gas more efficient.

(8) Breakers
Once the shale has been fracked and the proppants are lodged into the fissures, the fracking fluid has to be extracted to allow oil and/or gas to flow. Breakers are pumped into the well and react with the gelling agent, decreasing the viscosity of the fracking fluid. By making the solution less viscous, the fluid can be extracted while leaving the proppant in place. A common breaker is the hemicellulose enzyme, which is used in washing powders and the food industry (Straterra).

(9) Acid Corrosion Inhibitor and pH Control
Acids like hydrochloric acid (HCl) that are used in the fracking fluid can have a corrosive effect on the well bore casing. To protect the pipes, an acid corrosion inhibitor is used to protect the well casing (McCurdy, 2012). Furthermore, the addition of acids can cause the pH to plummet below neutral, which might make some of the other functional reactions less effective. To account for this concern, "pH buffers" are used to stabilize the pH. These chemicals are usually assorted compounds that can be found naturally and synthetically (Colbon, 2010).

Flowback Fluids

The flowback fluid is the water that was pumped down only the breaker has been applied to thin the water, leaving the sand or ceramic proppants behind. The flowback fluid can include chemicals that were not a part of the original frack fluid mixture, but were extracted from the shale. These compounds which originate in the shale may include brine, sands and some trace minerals; such elements can be a cause for public health concerns [2].

Risk assessment through chemical analysis

Comprehensive chemical information is available for some, but not all chemicals used in fracking. Some chemical disclosures contain ambiguous information, and incomplete Material Safety Data Sheet (MSDS) records (Samson Resources Corp, Riva Ridge well). Even when MSDSs can be found, they do not always contain toxicological or ecological information (LoSurf MSDS, Halliburton, 2009). Some compounds identified in fracking fluids are not specific chemicals, but are rather classified by a product name (e.g LoSurf) or chemical class (e.g light hydrotreated petroleum distillates), creating uncertainty about the exact composition or toxicity. Additionally, the chemical composition of fracking fluids is continuously changing, reflecting advances in technology as well as regulated or voluntary changes which may affect the environmental impact. This, combined with the fast pace of fracking development, introduces further uncertainty into any analysis of chemical impacts. Efforts to simplify and classify the potential mobility of fracking chemicals have been confused by the nature of fracking fluids, which contain surfactants to suspend otherwise insoluble compounds. Because of the function of surfactants, any compound present in fracking fluid is potentially mobile in aqueous solutions.

The complexity of fracking compound chemistry is emphasized by our research considering polyacrylamide. Polyacrylamide is commonly used as a gelling agent and friction reducer in fracking fluids. Although polyacrylamide itself is not toxic, it can degrade into acrylamide subunits, which have much greater toxicity than the polymerized form. Manufacturing processes often result in some (0.05 - 5%) acrylamide residue within polyacrylamide products. Acrylamide is a known neurotoxin, is water soluble, and is readily absorbed through multiple pathways into humans and animals (Smith et al., 1997). The use of polyacrylamide therefore presents a possibility of contributing a dangerous toxin to any area exposed to fracking fluids. However, polyacrylamide has many other uses as well. It is used as an amendment to reduce erosion and compaction in soils, it is used in ionic form to increase precipitation rates of solids during water treatment, and it is even used in children's toys (e.g. Test-Tube Aliens). Additionally, acrylamides can directly form in carbohydrate rich foods cooked at high temperatures, such as french fries (ATSDR, 2009). Because of the uncertain processes of degradation, which may act on fracking fluids, and the multitude of other potential sources, it is difficult to assess the risk which polyacrylamides in fracking fluids pose to water quality and human health.

The exploration of polyacrylamide emphasizes the difficulty in determining the potential impacts of fracking fluids with certainty. Efforts to qualify the risk or potential for water contamination based on the chemicals used have revealed an unexpected level of toxicological uncertainty, and a multitude of contamination sources and pathways. Additionally, the natural origin of the toxic chemicals used in fracking reveals an interesting paradox. In some cases, these chemicals are products distilled or isolated from petroleum products, and occur naturally in the same formations in which fracking occurs. Because of the uncertainty associated with the identity, toxicity, and mobility of chemicals in fracking fluids, and the natural toxicity contained in oil and gas containing formations, it is difficult to estimate the potential for fracking-derived water contamination by considering only fracking chemicals.

The potential pathways for water quality contamination and degradation are: (1) direct underground contamination, (2) local surface contamination and (3) non-local contamination. Direct underground contamination into groundwater aquifers could occur during the hydraulic fracturing process. Local surface contamination could occur due to blowouts, the intentional removal of flowback fluids, and above ground infrastructural incidents. Non-local contamination may arise during the transportation of contaminated flowback and chemicals, to and from the fracturing site for use, storage or treatment [1,4,6].

Direct Underground Contamination

Direct contamination of underground sources of drinking water (USDWs) due to mobility of water or contaminants from between deep, petroleum containing formations has the potential to catastrophically affect drinking water quality. However, the probability of such a connection is unclear. It is commonly assumed that impermeable geologic layers between deep petroleum-producing formations and shallow USDWs prevent significant vertical movement. However, this isolation is dependent on the thickness and porosity of material separating the formations. The natural presence of toxic compounds in deep petroleum containing formations provides a way to understand connections between oil shale formations and USDWs. In areas where USDWs show existing water quality issues, there may be natural exchange between petroleum containing formations and USDWs. This is illustrated in the Pavillion, Wyoming area, which has historically had poor drinking water quality (Thomas E Doll, 2012), coinciding with a very shallow gas containing formation (the lower Wind River Formation, and the Fort Union Formation, occurring as shallow as 372 meters) (EPA, 2011).

Historical data can clarify natural groundwater connections, but not changes in geohydrological connectivity due to drilling or fracking. In areas with significant separation between producing formations and USDWs, studies suggest that even the largest disturbances created by hydraulic fracking still do not significantly reduce the isolation of producing formations (Fisher, 2010 ; MIT 2011 chapter 2 page 41). However, it is possible that hydraulic fracturing could have a more significant effect on connectivity in areas with less depth between producing formations and USDWs.

The borehole created in the process of installing a fracking well creates a possible pathway for the contamination of USDWs. For this reason, much attention is placed on sealing boreholes against vertical fluid movement by cementing the area between the well itself and the larger borehole. However, this cementing process is not perfect, and issues with cement bonding are not uncommon (EPA 2011, Bellabarba et al., 2008). For this reason, there are ongoing regulatory and technological developments concerning cementing practices.

New developments in cementing technology include better practices for removing drilling fluids before cementing (enabling better bonding between the cement, well casing, and bedrock), developments of hydrocarbon-activated self-healing cements, and developments in acoustic logging technology that assesses the quality of cement bonding. Although these advances in technology can potentially reduce the possibility of new wells providing pathways for contamination, existing wells which were cemented or tested using inferior practices will remain a potential issue.

Minimal separation between producing formations and USDWs, oil and gas production since 1960, and cement bonding failures make Pavillion, Wyoming a 'worst-case' example for consideration of the impacts of fracking on USDWs. Since

2008, area residents have reported a decrease in drinking water quality following nearby fracking activities. The US EPA is currently investigating these complaints, with a draft report recently released (EPA, 2011). This report has not undergone final peer review, yet it provides insight into the potential for USDW contamination. The report relies on extensive water sampling at multiple locations and depths (Wright et al., 2012), identifies the same pathways for contamination which are discussed here, and discusses documented cases of USDW contamination in Ohio and Pennsylvania due to incomplete cementing of the well. The study suggests that (1) waste fluid storage pits are responsible for contaminated groundwater plumes, and that (2) there is enhanced gas migration into USDWs due to the fracking process. Energy industry groups hotly contest the second suggestion, and final conclusions await the input of the peer review process. Despite some remaining uncertainty, the EPA study of water contamination issues in Pavillion establishes probable connections between methane concentrations in water and subsurface fracking processes, and between chemical contamination of water and fracking-related surface processes. However, separation between oil and gas containing formations and USDWs in Pavillion are much thinner than typical oil and gas producing areas. It is therefore reasonable to conclude that the thickness and form of geological separation is relevant to the issues of USDW contamination.

In addition to the draft report concerning fracking impacts in Pavillion, the EPA is conducting a broader study of the issue. This study, which is motivated by citizen concern and congressional mandate, will focus on water quality issues, and will consider existing data from relevant studies, as well as case studies spanning diverse geological formations. A final report is expected to be released in late 2014. Because of the high economic and environmental stakes of fracking, and the diversity of opinion regarding fracking, the current EPA study faces intense and ongoing scrutiny from congress as well as industry and public groups. Recent hearings illustrate the contentious environment surrounding this current study, and the diversity of perspective among the congressional representatives (US House Committee on Science, Space, and Technology, 2011). Because of the independence of the EPA, the intent to synthesize existing studies with new research, the close scrutiny of methodology, and the upcoming peer review process, the 2014 EPA study will provide a reliable analysis of the impacts of fracking on groundwater quality.

Local Surface Contamination

Above ground there is an abundant and diverse set of incidences that have resulted in groundwater and surface water contamination (Riverkeeper, 2012; The Cadmus Group, Inc, 2009). Local surface contamination may result from infrastructural failures on site due poor maintenance, chemical storage failure, human error, and blowouts. The scope of environmental implications that are caused by such incidents are not well known due to the diversity of chemicals being used, although there have been recorded instances that have resulted in fish and aquatic life kills. On October 6th, 2009 approximately 250 barrels of diluted hydraulic fracturing fluids were spilt onsite due to a transmission line failure on a well pad near the Hopewell Township in Pennsylvania (Riverkeeper, 2012). The fluids entered a tributary of the nearby Brush Run River, a high quality warm water fishery. The spill resulted in the deaths of more than 168 fish and other aquatic life.

On June 3rd, 2010 a blowout occurred, spilling wastewater and natural gas into two nearby streams in the Clearfield County of Pennsylvania, 100 miles from Pittsburgh (Riverkeeper, 2012). Up to 35,000 gallons was retrieved from the streams; however, investigators believed that a possible 1 million gallons of wastewater had been released. The incident was caused by failure to use proper well control procedures. Onsite accidents that contaminate water resources occur regularly, on different scales, with a variety of chemicals. Unfortunately, it is difficult to quantify the effects of such incidences due to the current lack of knowledge concerning many of the chemicals involved.

Non-local Surface Contamination: Transportation

The movement of equipment, chemicals, produced water, solid wastes, and flowback fluids to and from well pads is an intensive process that requires significant amounts of transport on a regular basis. On average each well pad requires 890-1340 truck journeys over its lifecycle (MIT, 2011. With large-scale operations countrywide, the possibility for human error, such as vehicle crashes, and storage failure, such as tank ruptures, are inevitable. The possibility of trucking accidents resulting in spills is further enhanced when poor working conditions may be prevalent, perhaps under circumstances with highly fatiguing working routines, inexperienced drivers that are hired to fill the growing transportation sector, and transportation across poorly developed roads in rural areas that are often not suitable for intensive traffic pressure. Transportation accidents have the potential to contaminate surface and groundwater supplies in areas far from the initial well pads location. An example of a significant contaminating incident occurred when a truck transporting treated fracturing fluid crashed near Watson, Pennsylvania, resulting in the spilling of a 3600 gallon mixture of brine, salt, and chemicals (Lockhaven, 2011). The accident occurred near Pine Creek. Officials were not sure on the value of fluids that entered the waterway. Not every accident will result in a significant level of contamination of water resources, however many have the potential to end that way. A truck carrying fracking lubricant (a mixture of clay and mineral oil) crashed directly into a creek in the West Liberty county of Ohio. An unknown amount of the lubricant was spilled into the creek (Hanson, 2012). The spill was said to have been effectively cleaned up within a few days. There have been several cases where offsite contamination accidents have occurred, however uncertainty surrounding the implications of the contamination is still prevalent due to the inadequate understanding of the chemicals involved and the potential water contamination pathways at the diverse spill sites.

WASTEWATER TREATMENT

Flowback is the chemical laden mixture that is returned to the surface. Anywhere between 15-80% of the volume of injected fluids are pumped back up to the surface (EPA, 2010), the exact amount of which varies with the site-specific nature of the geology and the company-specific procedures. In addition to the fracking fluids, heavy metals, radioactive materials and salts from the geologic layer are brought to the surface and stored in these impoundments. Since a well can be fracked multiple times, some companies reuse this flowback to conserve water and recycle the fracking compounds. Treatment systems for flowback include injection wells, settlement ponds, wastewater treatment plants, mobile integrated treatment systems, and membrane brine concentrators.

Injection wells

The primary disposal method for flowback is to re-inject the fluids into a deep well. Injection wells have been used since the 1930's to dispose of "brine," or salt water, that results from drilling. The EPA has created regulations and classes of injection wells, and because of these regulations, injecting wastewater in a well near the active drill site is not always possible. When injection into local wells is impossible, companies are allowed to send wastewater out-of-state to other injection wells. In any case, the disposal of wastewater in injection wells must meet the applicable Safe Drinking Water Act (SDWA) requirements in section 1422 or 1425 to ensure that below ground sources of drinking water are not contaminated.

Settlement/Evaporation Ponds

Before, or instead of re-injecting flowback fluids, the fluids can be treated by allowing the insoluble portion to settle out. This process can reduce the expense of treating or disposing of the remaining fluid. However, the resulting sediment can be toxic, and the time required for complete settlement introduces the possibility of significant contamination of soils or shallow groundwater due to leaks in the settlement pond liners.

Purestream Technology offers a system that sits at the well-head and treats the fracking fluid as it is returned to the surface. The treatment process scrubs out hydrocarbons, toxic organic compounds, heavy metals, excess oil and gas, and naturally occurring radioactive materials. This 'cleaned' water is more pure than the standard EPA approved drinking water (americanprogress.com). This cleaning method can be done more easily and cheaply than trucking it to a treatment plant. This purified water can be evaporated back into the environment or used again in additional fracking processes. These such settlement ponds are regulated by Montana Board of Oil and Gas.

Evporation ponds are similar to settlement ponds, which are also regulated by Montana Board of Oil and Gas. The flowback fluid is put into settling ponds, but then misters are used to evaporate some of the water. However, there is the possibility of evaporating some chemicals that can become volatile when exposed to air, as well as evaporating the water, which is the main target (americanprogress.com). This evaporation of water allows the amount of fluid that is transported to injection wells to decrease.

Wastewater Treatment Plants

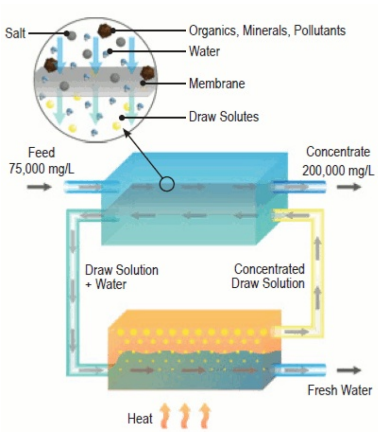
Fracking wastewater contains high levels of total dissolved solids (TDS), which can be corrosive, harming sewage treatment facilities and interfering with industrial equipment. Usually the wastewater treatment plants are privately owned, and the treatment of flowback water results in dilution rather than removal of pollutants found in fracking waste. Treatment is energy intensive and generates concentrated residual byproducts that have to be disposed of.

Mobile Integrated Treatment Systems

Ecologix Environmental Systems designed a mobile treatment system that includes a mobile chemical treatment unit and a mobile Dissolved Air Floatation (DAF) unit. These units remove up to 99% of all the suspended solids, emulsified oil and dissolved metals from the water, allowing it to be used in the next series of wells. Mobile treatment systems process up to 10 times more water than most comparable filters, so they have the largest water treatment capacity of any comparable filtration system in the Oil and Gas industry.

The mobile integrated treatment system consists of a mobile chemical feed (MCF), a mobile chemical treatment (MCT) and a dissolved air floatation (DAF). The mobile chemical feed (MCF) is an insulated, air-conditioned trailer, containing chemical feed pumps and programmable controls to treat flowback water based on the flow rate and impurity levels in the water. The treatment chemicals are fed into chambers of the mobile chemical treatment (MCT) where they are mixed to attain the desired precipitation reaction. The solids that result are removed in the dissolved air flotation (DAF) system. The dewatering unit (DW) receives sludge from the DAF and drys it for safe disposal at a landfill. The mobile polishing system (MPS) is capable of treating water to the highest and most demanding effluent discharge levels to keep in compliance.

Membrane Brine Concentrator



Oasys' Membrane Brine Concentrator (MBC) Process

Figure 4. The processes of a membrane brine concentrator. Source: http://www.desalination.com/wdr/48/10/fo-takes-big-step-

Another approach to water treatment, designed by Oasys Water Inc., is the Membrane Brine Concentrator (MBC) for water treatment. The membrane is used in forward osmosis for up to 24 months to treat high saline water from fracking activities. Figure 4 shows how the water is being managed by treating the water through evaporation. The membrane works by relying on osmotic pressure gradient rather than pressure or heat energy to drive the water from the feed solution through a semipermeable membrane to dilute a concentrated ‘draw solution’. The product water can then be separated from the draw solution by heating to 70 °C using a diesel-driven heat pump.

SOCIAL IMPACTS

Community Concerns

When most environmental scientists think about hydraulic fracturing they consider the processes involved, worry about the permitting and environmental laws, or think about the reclamation needed for the area after the site has been left; but few consider the impacts that these processes have on the local community. These community members have the best understanding of how these processes affect their local environment. They have seen their towns go from zero impact to having large amounts of wells installed with the accompanying traffic and population increases. Few to none of these community members have degrees in an environmental science, but they all have seen the heavy equipment tear up their roads, the pipelines scar their hillsides, and worry about the water that comes out of their faucet.

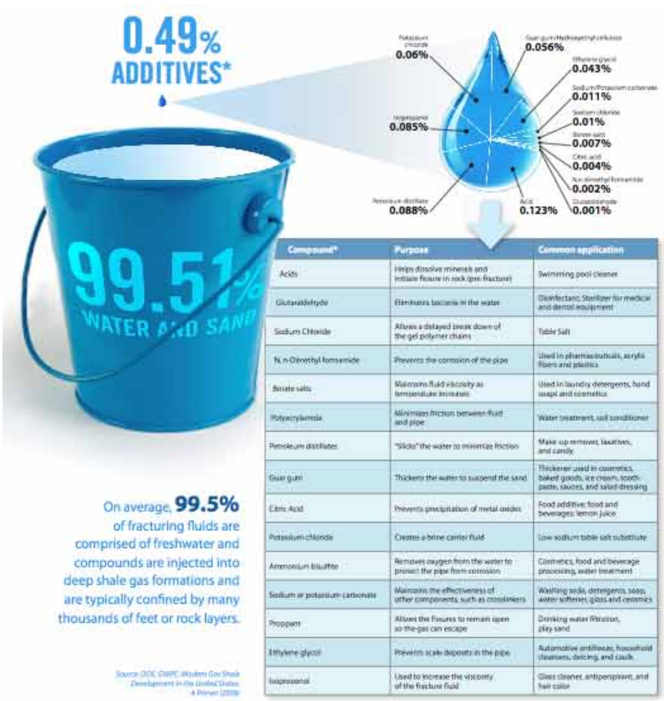


Figure 5. Industry group figure of the chemical composition of an average fracking solution. Source: http://theautomaticearth.com/Energy/fracking-our-future.html

One of the biggest issues of concern between the community members and the natural gas industry is communication. The industry wants the members to believe that there is nothing to worry about in terms of their health and safety. Energy In Depth, a public relations company for the oil and gas industry recently published a report stating that a "typical" fracking solution is 95.51% water and sand, with only a few harmless chemicals thrown in (for example, citric acid and table salt) (Meyers 2012). This masking of the truth can also be seen in figure 5 (Energy In Depth 2012), which lists some of the chemicals used in a fracking solution and its common household use. This drastically skews ones perception of what dangers are involved if this solution enters the local water source and is consumed by community members. According to Robert Meyers, the director of environmental studies of Lock Haven University located in North Central Pennsylvania, hydro-fracturing is the single biggest environmental threat to Pennsylvania that this generation faces (Meyers 2012).

The rumor that people can light their faucet water on fire is commonly discussed when considering hydraulic fracturing and its effects on water quality. It is only human to assume this rumor is true, but are we jumping to conclusions too quickly? In fact this and similar water quality issues are not uncommon in areas heavily used for hydraulic fracturing. Several months ago Janet and Fred Mcyntyre watched as the natural gas industry took over their town in Butler County, Pennsylvania. They put up with the noise, the traffic, and the increasing population but the turning point came when the water in their kitchen and bathroom turned soapy and foamy and their dog suddenly died. "I had good water before, but now everyone around here has an issue with their well or health. Something's clearly not right," says Janet. "Can I put my finger on it and prove the precise cause beyond a doubt? No, but the only thing that's changed around here is gas drilling"(Steinzor, 2012).

Another similar case, in a nearby county is in 2007, Angel and Wayne Smith knew very wrong when their well water turned brown and then water started bubbling up through their barn floor and an oily sheen and foam appeared on their pond. Also, a strong propane odor was later noticed and followed by headaches, nosebleeds, fatigue, sinus problems, throat and eye irritation, and shortness of breath. In the short space of several months, a horse and three cows died and twelve calves were either miscarried or stillborn (Steinzor 2012).

The last example is in Ohio; a distance away from Pennsylvania, but an area still greatly affected by the natural gas industry. (Ohio lies over the same gas formation that Pennsylvania does, the Marcellus shale). In December 2007, the basement of Richard and Thelma Payne's home in Bainbridge Township, Ohio exploded. Fortunately, neither Richard nor Thelma were harmed in the explosion. In addition, 19 area homes were evacuated because of natural gas. The report by the Ohio Department of Natural Resources done in 2008, concluded that the explosion and contamination was caused by "inadequate cementing of the production casing" by the drilling company, Ohio Valley Energy Systems, which led to migration of natural gas into natural fractures in the bedrock below the drilling casing. The gas entered the water supply that the Payne family uses and exploded within the pipes of their home (Meyers 2012).

Unfortunately hundreds of pages could be filled with similar stories such as these. It is important to not dwell on such horror stories but to learn from them. From these events, new policies can be made, and new environmental laws can be passed. Community members can be informed of what is happening around them and maybe want to become more involved with the testing of their town's ground water and air quality.

Economic Considerations

There are also many changes at the community level that are having an effect on local economics. The towns that have a high influx of drilling activity are known as "boom towns." In southern Texas, employment increased by 27% between 2010 and 2011. During the same time period, employment increased by 41% in Williston, ND (USHMC, 2012). Many of these jobs are not directly related to labor on fracking teams. Service jobs are created in restaurants and hotels to accommodate increasing needs resulting from larger population sizes. This job boom can be good for the national market, but it may only be temporary. Once the wells in the area become unproductive, the labor moves to a new drilling location and the towns may experience effects of decreases in population.

Why fracture shale formations if it may causes community and environmental stress? Why not put it on hold until we know more about the impacts and can design technology to protect the environment? The new developments in extraction have catapulted us into a Gas Rush. According to one estimate from Cambridge Energy Research Associates, shale provided 20% of US gas supply in 2009, compared to only 1% in 2000, and this is expected to rise to 50% by 2035 (Kefferputz, 2010).

Americans, in particular, live a high energy lifestyle. Since the mid-1980s our oil and gas consumption as a nation has been rising (FIG. X). The amount that we have been producing has changed too though. Oil has had a steady decline in barrels produced daily since the 1980s. But beginning around 2008, our oil production began to increase (Fig. 6). Natural gas has been increasing steadily since the 1980s, but has had dramatic rises in production since 2005. The United States has increased natural gas production by 4.8 million barrels per day since 2002 and in 2010 was the second leading natural gas producing country (Enerdata, 2011). The rise of natural gas and oil production in the United States has had many economic changes considering imports and exports of oil and natural gas, price, and the job market.

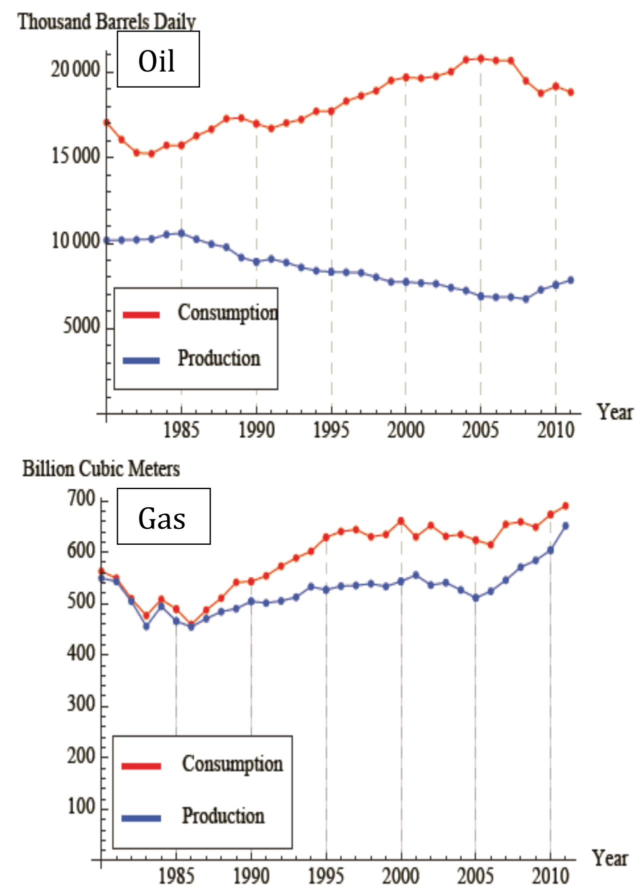


Figure 6. Consumption and Production levels of oil (top image) and natural gas (bottom image) by year (Fitzgerald, 2012).

U.S. dependency on foreign resources has been an issue for many years. Imports of natural gas reached a high in 2007. In 2011, the U.S was importing over 1 million cubic feet of natural gas less than 2007. Since 2007, consumption has slightly increased (EIA, 2012). Production has continued to have a steady increase, closing the gap between how much we consume and how much we produce (FIG X). There is a similar comparison with consumption and production of oil, although the changes are not as dramatic and the ratio between consumption and production is much greater. Today, most of our imports for natural gas come from Canada and Mexico (EIA, 2012), whereas Canada and the Persian Gulf are the leaders for oil imports (EIA, 2012).

Tim Fitzgerald at Montana State University states that "in rich countries, demand for oil has peaked, but supply continues to increase." This trend will have effects on the price of oil, which has decreased compared to the prices seen in 2007. Given that our demand for imported oil is greater than our demand for imported natural gas, it is sensible that oil prices are higher. Some economists imply that the price for oil will continue to decrease (Fig 7); but, projecting into the future is uncertain. If our technology allows the U.S. to produce more oil than we currently are (and the trends show that we are increasing oil production) then it is possible oil prices will continue to fall again.

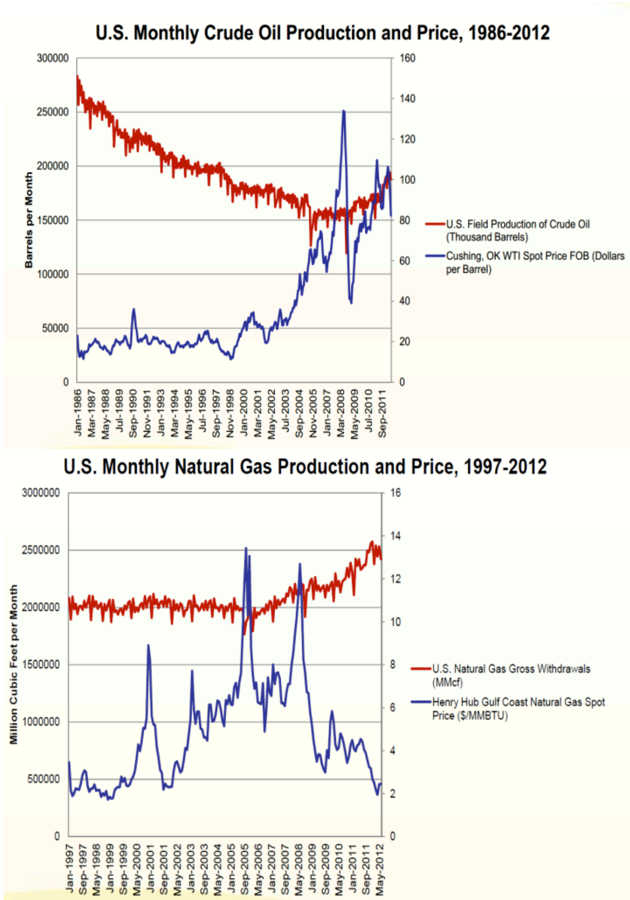


Figure 7. Trends with production and price of Oil and Natural Gas (Fitzgerald, 2012).

Some trends suggest the supply already outweighs the demand for natural gas. Figure X shows the recent changes in withdrawals and price. For natural gas, it is evident that the price is going down. This trend may or may not continue, and like science, economics is uncertain.

Montana Mineral Rights Pertaining to Oil and Gas Extraction

In Montana, lands deeded out in the 18th and 19th centuries included the mineral rights along with the surface estate. These mineral rights remain with the original land unless severed into a separate mineral right at a later date. Most land in Montana does not fall under this category, however, with about 11.7 million acres of private land being split estates with separate surface and subsurface rights, the latter of which are owned by the federal government (Bureau of Land Management, 2012). Under the Stock Raising Homestead Act (SRHA) of 1916, homesteaders could claim up to 640 acres of nonirrigable land as long as it had been previously dedicated as "stock raising" land by the Secretory of the Interior (Bureau of Land

Management, 2012). Due to the rising interest in mineral exploration, the homesteader could claim the surface rights, but subsurface rights would remain under federal ownership (Bureau of Land Management, 2012). The government allowed land owners personal use of minerals occurring on their land in minimal amounts in order to improve land usage within the boundaries of the estate. Landowners were not allowed to sell the mineral rights under their lands or benefit from a sales contract or permit (Bureau of Land Management, 2012).

Thus there are two main types of landowners in Montana, those who own the mineral rights and those whose mineral rights are owned by the Federal Government or a separate private party. Each type of landowner is affected in very different ways by prospective oil & gas exploration and extraction activities that target their land.

The minority of owners who have the mineral rights to their land are in a much more advantageous position than those who don't. As sole owners of the mineral rights, it is up to them whether or not to enter into business with energy companies that show an interest in extracting from their land. If the owner is willing to engage with these companies, they sign an Oil, Gas, & Mineral lease. This agreement allows the company to drill and extract on the owner's land in exchange for a lease bonus payment; an upfront cash consideration usually based on a per acre payment, and a royalties percentage based on the net or gross production of the extractions themselves (Services, 2011). The royalty percentage is the main source of revenue for landowners leasing out their mineral rights; in the 2011 fiscal year landowners reported $32,212,195.92 in royalty revenues due to oil extraction and sale (Revenue, 2011). In this type of agreement the power is with the landowner as he is in the position to negotiate on his own behalf and set his own price based on how badly the company wants to access his land. The owner also has the power to make stipulations as to how much the company must pay in return for damages to the land due to the setting up and maintaining the drilling sites as well as damages from the actual drilling process. The landowner can also specify if there are certain areas of his land that are off limits to drilling or development.

A landowner who does not own his mineral rights finds himself in a much more complicated situation, and one that is harder to benefit from personally. The majority of land owners in Montana fall under this category. The majority of mineral rights in Montana are owned by the Bureau of Land Management (BLM), the state government, or a private entity other than the owner of the surface rights. These parties maintain the right to sell the mineral rights or, more likely, lease them to an interested company. The most important part of split estate law is that the mineral rights holder, or leaser, has a legal right to access and extract his holdings regardless of whether or not the surface rights owner is willing to allow it (Council, 2007). There are many regulations in Montana state law that protect the landowner and his land from exploitation by oil & gas extraction companies.

Companies who want to explore the possibility of extracting oil or gas from an area of land under private ownership for which the company has the mineral rights must apply for a permit from the County Clerk and Recorder, notifying the landowner of their intent for exploration, establishing the dates exploration will occur, and providing the landowner with a copy of Title 82, chapter 1, part 1 and Title 82, chapter 10, part 5, Montana Code Annotated (MCA) and a current copy of the “A Guide to Split Estates in Oil and Gas Development” brochure (Council, 2007). If the company discovers wishes to proceed with drilling, they must apply for a drilling permit by proving that the area of drilling is suitable to provide a reservoir for the storage of gas or oil, the amount of oil or gas in the area is recoverable and that they have “in good faith” tried to obtain a written surface use agreement and a written waiver for access to the land from the landowner and agreed to pay for damages in an agreed amount with the landowner (Council, 2007)(MCA 2011). Once the company has received its drilling permit, they must present it to the landowner at least 20 but no more than 180 days prior to drilling, inform the owner of any activity that will cause a disturbance to the land, and again provide the landowner with the appropriate sections of the MCA (Council, 2007). The company is also required to inform the landowner of the extraction work plan in order to allow the landowner to make an assessment of potential damages to their surface holdings. The landowner and company are also encouraged to discuss the times and frequency of access to the land, the expected duration of drilling activities, and other concerns the landowner may have such as dust mitigation or the impact on seasonal agricultural operations (Council, 2007). Throughout the process it is in the landowner’s best interest to work with the company to coordinate all surface activities such as the placement of roads, wells, holding tanks, power lines, and impoundment ponds, in order to lessen the impact on agricultural and range operations. Once these requirements have been satisfied, the company may proceed with the drilling and extraction process as allowed by the restrictions of their permits.

Obviously not all of the lands that companies target for exploration and extraction are privately owned, many areas of interest are owned by the state or federal government and are controlled and regulated by government entities. The Bureau of Land Management (BLM) manages over 240 million acres of public land nationwide as well as 700 million acres of sub-surface mineral estates. Under the Mineral Leasing Act of 1920 and the Mineral Leasing Act for Acquired Lands of 1947, the BLM has responsibility for oil and gas leasing on over 564 million acres of BLM, national forest, and federal lands as well as some state and privately owned lands whose mineral rights have been retained by the federal government (U.S. Department of the Interior, 2012). According to the Federal Onshore Oil and Gas Leasing Reform Act of 1987 the BLM may issue two kinds of mineral leases on selected sections of the lands it administers to; competitive and non-competitive. Competitive leases are not to exceed 2,560 acres while non-competitive leases may be up to 10,240 acres (U.S. Department of the Interior, 2012). Non-competitive leases only become available if the land has been offered for competitive lease at an oral auction and not received a bid. Oral auctions are held at least once per yearly quarter and sometimes more often by state BLM offices. At these auctions companies can bid for the right to explore, drill, extract, and dispose of any oil and gas contained on the selected parcels of land up for auction. Once a company has acquired a lease for a parcel of land, it is up to the BLM to oversee the development of mineral resources on that land and make sure the company is proceeding in an "environmentally responsible manner" (U.S. Department of the Interior, 2012).

Oil and Gas Development Regulations: Montana

There are two agencies primarily responsible for overseeing the oil and gas development (OGD) in the state of Montana. The first, as previously mentioned, is the BLM, which administers and regulates the OGD occurring on federal lands or on lands where the federal government owns the mineral rights (Dept. of Interior, 2009). The second is the Montana Board of Oil and Gas Conservation (MBOGC), which administers and regulates OGD on private or state lands within the state. The BLM and the MBOGC have specific and slightly different regulations pertaining to the different aspects development ranging from initial exploration and discovery, to the setup of a well site and the requisite permits required for development, and finally the required reclamation of a well site before it is abandoned.

In order for OGD to proceed on lands administered by the BLM, the developer must complete an application for permit to drill (APD). This application must include: a completed permit to drill form, a well plat certified by a registered surveyor and accompanied with applicable geographical coordinates, a drilling plan, a surface use plan of operations, evidence of bond coverage, operator certification, any other information that might be pertinent to the operations of the well such as any directional or horizontal drilling that is anticipated, and an onsite inspection by technical staff of the BLM (Allred, 2007). A complete APD is then reviewed by technical specialists from the BLM and any other agencies the BLM might be coordinating with (2007). Contained within the drilling and the surface use plans of the APD are important safety, environmental mitigation measures, and the surface reclamation plans of the proposed project. If these aspects of the application do not sufficiently comply with important statutes such as NEPA or are not deemed satisfactory by the reviewing staff, the application will either, be denied, conditionally approved, or denied with recommendations by the review board as to how to correct the application (2007).

Currently if the operator of a well wants to complete "routine fracturing or acidizing jobs" they do not need prior approval; they only need to file a proposal beforehand in their APD if the operations are "nonroutine" or if additional surface disturbance is involved (43 CFR, 3162.3-2). Due to public concern, in May of 2012 the BLM proposed a rule that would update the rules applying to fracking. If adopted, a few of the major changes implemented would be: all fracking, acidizing, or other well stimulation jobs would require prior approval (this would be included in the APD process); it would require disclosure of specific information about the water source to be used in the fracturing operation, including the location of the water that would be used as the base fluid; it would increase the transparency with regard to the fluids used during the stimulation process; there would be "assurances that well bore integrity is maintained throughout the fracturing process"; and there would be a requirement that operators put in place appropriate plans for managing flowback waters from fracturing operations (Federal Register, 2012). These changes would only apply to those lands managed by the BLM so they would not affect the majority of the development occurring within Montana, which is regulated by the state; in 2011 the BLM approved 26 APD's within the state of Montana (Dept. of Interior, 2011) and the MBOGC approved 757 permits (488 re-issued, 118 vertical, and 151 horizontal)(DNRC, 2011).

The MBOGC has "primacy" in Montana over oil and gas development within Montana and must work closely with other agencies, including the BLM, to administer and regulate OGD. Being loosely attached to the Montana Department of Natural Resources and Conservation, the board was established in 1953 (Board, 1989) and in 1996 it took control of oil and gas well operations within Montana. The MBOGC has four primary purposes: "to prevent waste of oil & gas resources, to conserve oil & gas by encouraging maximum efficient recovery of the resource, to protect the correlative rights of the mineral owners so that each owner recovers its fair share of the oil & gas underlying their lands, and to prevent oil and gas operations from harming nearby land or underground resources" (Board, 2011). The board consists of seven members: three from the oil and gas industry, two landowners (one must have mineral rights) living in counties where there is oil and gas development, and two public members, one of which must be an attorney (Board, 2011).

The rules of the MBOGC that govern the oil and gas development are contained in chapter 36.22 of the Administrative Rules of Montana (ARM) and begin with a discussion of the regulations that pertain to the first phase of development, the exploration phase. If a company desires to drill an exploratory well they must first notify the state and obtain a permit (ARM, 36.22.503). During the exploration and discovery phase of a mining operation there are regulations pertaining to the prospecting operations, specifically drill holes. Furthermore, prospecting operations must be conducted to completely avoid the degradation or diminution of any existing or potential drinking water supply and to avoid any adverse impacts to existing or potential mining operations (17.24.1005). Once the prospecting phase of the development is complete, all exploratory drill holes must also be abandoned using appropriate techniques to ensure prevention of escapement of any water, oil, or gas from the drill holes (17.22.647). The prospector must also ensure prevention of contamination of all surface and ground water and prevent inter-aquifer mixing using proper techniques to ensure prevention of aquifer contamination by surface drainage (17.22.647). Finally, the prospector must reclaim all surface impacts and prevent settling that may result from prospecting related activities (17.22.647).

If the company decides to commence production, they must apply for a drilling permit through the MBOGC. In an effort to incorporate necessary environmental review into the permitting process and to come into compliance with the rules stipulated in the Montana Environmental Protection Act (MEPA) required by ARM 36.2.521, two environmental impact statements for oil and gas development within Montana have been done (1989, 2003). Upon the recommendations made within these documents, the MBOGC now completes a preliminary environmental assessment (EA) before approving the drilling application (ARM, 36.22.202). The oil and gas development EA's are checklists of potential environmental impacts (Appendix 1; Board 1989, 220-222). During this review process the MBOGC works with any other state or federal agencies that have specialized knowledge or insight into the potential environmental impacts (1989, 223-224). If there are questions about the potential impacts derived from insufficient information or other sources, the MBOGC determines whether a full Environmental Impact Statement (EIS) is necessary and from there whether the permit should be issued (1989, 219 and 223). The environmental impacts of the proposed well are public and the Board must publicize whenever there is a hearing to review an EA and EIS via a legal notice in a local newspaper (ARM, 36.2.543). If the potential environmental impacts are sufficiently addressed, the permit for drilling is issued. A flow chart illustrating the various routes the environmental review process can take is found in appendix 2 (Board 1989, 213).

Hydraulic fracturing, acidizing, and other well stimulation activities are considered permitted by the drilling permit if it includes an adequate description of the proposed well stimulation activities, which include "the processes, anticipated volumes, and types of materials planned to be used" as well as the "max anticipated treating pressure or a written description of the well construction specifications which demonstrate that the well is appropriately constructed for the proposed fracture stimulation" (36.22.608). The disclosure of the names and of the treatments to be used as well as the names and chemical makeup of the principle components or chemicals used during the drilling, fracturing, and cleanup processes are required by law if a fracking permit is to be approved (ARM, 36.22.1015). The disclosure of fluids and chemicals used which are deemed "trade secrets" is not required by law unless there is an emergency and then they must be released to either a doctor or the MBOGC who must sign non-disclosure agreements (36.22.1016). If the operator does not know if they are going to do any of the well stimulation activities at the time of the permit they must submit a notice of intent including the above information at least 48 hours ahead of scheduled activities (36.22.608).

Once the permit is approved and drilling commences the owner must post a bond with the state and, as previously mentioned, notify the landholder and inform them of the drilling schedule (36.22.601, 36.22.602). The MBOGC is responsible for establishing drilling spacing units and the developers are required to adhere to those units and the laws associated with them (36.22.701, 36.22.702, 36.22.703). The use of blowout prevention equipment, and the installation of safe surface casings to a depth below freshwater used for agriculture and domestic use are required in the establishment of the wells (36.22.1014). The casing must be tested to a compressive strength of 300 pounds per square inch. Hydraulic fracturing wells must test the casing with the maximum anticipated pressure for 30 min with no less than 10 percent pressure loss (36.22.1106). In the event of a spill, fire, blowout or any other emergency the owner must notify the Board and fill out a report within five days of the incident (36.22.1103). The operator is responsible for all damages to property either resulting from "lack of ordinary care" or "caused by drilling operations and production" and they are liable for cleanup and removal of the damaging wastes (MCA 82-10-505). Furthermore, the owner must also promptly clean up spills or leaks of any fluid or water that has more than 15,000 ppm total dissolved solids regardless of the amount. In the event of an emergency, hazardous substances can be stored for 48 hours in an earthen pit before they must be disposed of properly (ARM, 36.22.1103).

Regulation of Waste Management

During the drilling process, oil and gas wells can produce wastes ranging from solid waste to fluid waste. Solid waste includes containers of the products involved in the process, to earthen wastes produced by the act of drilling. Fluid wastes typically are water-based wastes that may include flowback fluids from the fracturing process or water returning to the surface carrying sediments from the drilling process. According to the ARM 36.22.1005, the operator of a drilling operation must contain and dispose of all solid waste and produced fluids that accumulate during drilling operations so as not to degrade surface water, groundwater, or cause harm to soils. Solid waste and fluids must be disposed of in accordance to all applicable local, state and federal regulations. When salt-based or oil-based fluids are used in the drilling process within a riparian area, flood plain or in an irrigated crop field, all drilling waste and produced fluids must be disposed of off-site in a manner that adheres to local, state and federal regulations. An exception can be made if a proposed disposal method has been suggested by the well operator and reviewed and approved by the Montana Oil and Gas Board administration. Often times the drilling operation wastes are placed in an earthen pit near the drill site. If salt or oil based fluids are used in the drilling operation, the earthen pit must be lined with a synthetic liner that has been approved by the Montana Oil and Gas Board administration.

If earthen pits are used as a waste disposal area for a drilling operation, the well operator must apply for and receive a permit to construct the pit pursuant to ARM 36.22.1227. For pits or ponds that receive produced water containing more than 15,000 parts per million (ppm) total dissolved solids (TDS) in volumes greater than five barrels per day on a monthly basis, the pits must be constructed in cut material or at least 50% percent below original ground level and must be lined with an impermeable synthetic liner. If the bottom of the pit is underlain with porous, permeable, sharp, or jagged material the pit must be lined with at least three inches of compacted betonite prior to installation of an approved impermeable synthetic liner. Earthen pits must be constructed above the high water table and not located in a flood plain, riparian area, or irrigated crop land. Pits must also be diked or bermed, and the fluid level must be kept at least three feet below the top of the dikes or berms. In addition, a Montana Board of Oil and Gas administrator may impose more restrictive requirements regarding the construction and operation of earthen pits necessary for the prevention of degradation of surface and/or ground waters and contamination of soils (36.22.1227, sub section 3). When the drilling party constructs earthen pits that are utilized as a waste storage venue, they must construct, close, and restore the pits in a manner that will prevent harm to the soil and will not degrade surface or ground waters (36.22.1226, 36.22.1005).

The applicable Montana regulations for the disposal of drilling waste that cannot be injected back into a well, disposed of on site without causing harm to the soils or degrading the ground or surface waters, and is classified as "non-hazardous" is regulated as "special waste" according to the Montana Department of Environmental Quality (MDEQ) (MDEQ, 2012). These wastes can be disposed of at any class II solid waste management facility if that facility has updated their Operation and Maintenance Plan and those updates have been submitted and approved by the MDEQ (MDEQ, 2012). These facilities must also document the initial characterization of the wastes before accepting them. The initial characterization must include: "generator information; identification of the waste source location, volume, physical state, and type; identification of the process producing the waste; method of receipt; and contaminant concentrations" (MDEQ, 2012). In order to appropriately identify the characteristics of the wastes, the waste generator must collect at least one sample composed of five sub-samples per 200 cubic yards of waste (MDEQ, 2012).

The MDEQ not only regulates the disposal of the solid waste that is generated and transported off-site, it also regulates the air emissions from the machinery at the well sites. ARM 17.8 of the MDEQ administrative rules applies specifically to air quality concerns pertaining to oil and gas well facilities. MDEQ requires any owner of oil and gas facilities to apply for a Montana Air Quality Permit. The owner must install and operate air pollution control equipment and comply with air pollution control practices. They are also required to promptly repair any leaks within five days and they must make records of the required monthly inspections.

In Montana another permit is required before OGD can proceed: a permit for water use of both surface and ground waters (MCA 2011; 85-2-302) and before this permit is issued the use must be deemed as a "beneficial use". Montana is a Prior Appropriation state in regards to water rights, meaning the permit applicant also has to abide by regulations stating that water quality and usage amounts of a prior appropriator will not be adversely affected (MCA 2011; 85-2-311). In addition to meeting the demands of the Montana Annotated Code for a water permit, the well operators are urged by the American Petroleum Institute (API) to talk to local water planning agencies to determine where their water source will come from and the amount of water that they can take without putting undue strain on local water resources (American Petroleum Institute 2010).

In an attempt to ease the strain of establishing a well and conducting fracturing processes, some well operators extract water from ground water sources that have are unsuitable for drinking water. Aquifers that are not suitable for drinking water sources are referred to as Exempt Aquifers by the Administrative Rules of Montana (ARM) under Title 36 Chapter 22 Section 1418. Under this portion of the ARM, the Montana Board of Oil and Gas may exempt an aquifer from classification as an underground source of drinking water provided the aquifer does not currently serve as a source of drinking water and is not reasonably expected to serve as a drinking water source because, the aquifer produces or is capable of producing mineral, hydrocarbon, or geothermal energy in commercial quantities. An aquifer may also be exempt because it is situated at a depth or locations or is contaminated to a level that would make recovery of water for drinking purposes economically or technologically impractical. Any aquifers that are exempted by the Montana Board of Oil and Gas must also be approved by the EPA. These exempt aquifers may also be used for Underground Injection Control (UIC) wells, regulations pertaining to UIC operations will be discussed later in this document (36.22.1418).

Once finished with the drilling they must give notice of abandonment and they must "plug" any wells dug on the site and restore the surface as near as practicable to its original condition before they are finished at the site (ARM, 36.22.1302, 36.22.1303). The owner must restore the surface to its previous grade and productive capability, and must make sure the wells do not adversely impact the local hydrology (36.22.1307). After the wells are filled the owner must record the nature and quantity of the materials used in the plugging, the locations and extent of the plugs made, and also the size and amount of the casing left in any of the wells (36.22.1309). Once completed the developer is liable for the damages to the property and will have to compensate the surface owners for the loss of agriculture production and income, loss of land value, and lost value of improvements (MCA, 82-10-504). The bond posted by the company must be held on file with the county for an additional five years after the drilling has occurred (36.22.1208).

Plug and Abandon

With the oil and gas industry blooming across Montana and North Dakota, oil and gas wells appear to be popping up overnight. The big question then becomes: what happens next? Advancements in drilling techniques and technology have enabled oil and gas companies to maximize production in both newly drilled wells and past wells, but in the end what are we left with? The recent developments in rules and regulations concerning oil and gas drilling have shed some light on what we will be left with when an oil or gas well reaches its end.

Though huge advancements have been made relating to drilling and extraction methods, little has been since developed concerning the closure of wells. Throughout oil and gas industry history, there has been little regulation as to the treatment of wells once they have been deemed no longer economically viable. In the earlier years of oil and gas drilling, wells were just vacated and left as gaping holes in the ground exposing the surrounding environment and water supplies to possible contamination. Later on cement was poured down the drill hole as to plug the well. Today measures are being taken to reduce the environmental impact caused by oil and gas wells. The plugging and abandoning (P&A) of wells is method used close of the wells in order to minimize environmental contamination. This method includes sealing the well using a plug (commonly made of cement), removing all drilling and pumping equipment and material, and either replanting the area with vegetation species similar to those found in the surround areas or letting the area be reclaimed by the surrounding vegetation (MBOGC, 2012).

In the past, the plugging and abandonment of wells were carried out as an afterthought. This was partially due to the fact that little was known about the impacts of leaving the well open. A second reason was the cost; the oil company would have to pay to have the well plugged. Being as this process required the expenditure of money and man power with no profitable return for the oil company, wells were plugged using the lowest cost method available that would meet the minimum requirements. The use of lower quality materials and limited time led to failures in the plugging process of earlier drilled wells. Today old wells are now being put back into production use with the advancements in drilling technology that allow companies to take advantage of oil or gas reservoirs that were not possible to reach using earlier methods or to be used as injection sites for C02 and drilling water. In order for this to happen, the drilling company must first file the proper paperwork before reopening a plugged well. Once a well has gone through the plug and abandon process it cannot be reopened without prior consent from regulatory agencies and or petroleum engineer (Montana regulation 36.22.1303).

Currently regulations concerning the closure of wells vary from state to state. These regulations have become more in depth with an increase in focus on environmental impact and reclamation of well drill sites. Standards with regard to the cement materials and methods used in the plugging process have been implemented by the American Petroleum Institute. Well plugs are commonly made of cement material. In the past, a lack of properly prepping the drill hole led to a faulted plug and eventually a full failure of the plug. After the passing of the Safe Water Drinking Act (SWDA) a new method of plugging wells was adopted. This method is known as the displacement method. With the advancement and use of hydraulic fracturing in oil and gas extraction, extra measures have been taken as to how many plugs put in place in the well hole along with the plug locations. The displacement method allows drilling operators to accurately place plugs in the drill hole.

As mentioned earlier, cement is that material of choice for plugging well holes. The displacement method uses a specialized concrete mixture with characteristics required for making a secure plug. Special agents are included in the cement mixture that allows the cement to clean the drill hole to minimize contamination of the plug. The cement mixture is also used to force excess drilling mud out of the drill hole.

To begin the plugging process, tubing is placed down the drill hole and dry cement components are pumped down the piping to the plug depth. The cement will flow out the bottom of the tubing and flow back up around the tubing. Water is then pumped in behind the cement down the tubing and the cement fills in the areas occupied by the tubing to form a strong-sealing plug.

With an increase in regulations pertaining to the treatment of out-of - commission wells, oil and gas companies are now required to pay a bond before drilling. To reclaim their bond, companies must have met the post plug and abandonment conditions, including establishing a surface condition similar in working value of the land before drilling and the plugging material used must maintain its structural integrity and continue to keep the well closed off from the environment. If the required conditions were not met, the drilling company would forfeit the bond and the money would be used to ensure that the earlier said conditions were met or act as compensation payment for damage to the land. Once the well is plugged, the oil company must then file a completion report with the state. This report includes the methods used for plugging, the specs of the closed well: materials used, casing information, location of plugs, test measurements, and a statement of mud used in the plugging process.

Today, thousands of oil wells are scattered across Montana and have become a common fixture in the landscape. With the help of rules and regulations, all past, current, and future wells will meet the same end leaving little evidence of the oil industry behind.

When a well is closed—assuming no extraordinary contamination has occurred—one final measure must be taken to ensure that the site does not detract from the health of the landscape: revegetation. This step, usually mandated by the well permit, is vital for keeping the site productive for agricultural or wildlife use but also for bolstering public palatability of mining projects. Leaving a site devoid of usable vegetation or allowing it to be overrun with invasive weeds is generally unacceptable by public standards, and it is expected that a mined site will be returned to a level of ecological function similar to that which was present before the site was developed. However, restoration projects are not a guaranteed success; even with substantial funding failure is an ever-looming possibility that can be brought about by any number of shortcomings, be them human-induced or inherent in the site. It must be acknowledged that some sites will not be restored to a satisfactory state: some may function to a limited degree, while others may be irreparably damaged. Even under ideal conditions, restoration cannot always be expected to return a disturbed site to a pristine state.

The semi-arid conditions of the Great Plains, where a large amount of fracking occurs, are not conducive to revegetation. Most disturbed sites, if left unrestored, will quickly become dominated by exotic annual weeds (Ross 2000). Such species are well-adapted to rapidly spread into disturbed ground and exclude more desirable perennial species. For this reason, non-native perennial grasses that establish readily are often used to revegetate a site (Simmers and Galatowitsch 2010). This may preserve agricultural use on a site, but the quality of wildlife habitat can be greatly affected when non-native species dominate. Utilizing a wholly native seed mix, however, can be much more expensive and establish less reliably. Regardless of which species are used, over the course of several decades species diversity on restored sites can become low without regular monitoring and maintenance (Simmers and Galatowitsch 2010).

The high degree of disturbance characteristic of mine sites and access roads presents yet another challenge. Soil compaction, loss of topsoil, and interrupted hydrology limit the establishment of desirable species and perpetuate conditions under which invasives thrive (Simmers and Galatowitsch 2010). In years past, restoration protocols did not generally call for soil amendments or routine maintenance to remove invasive species because of the high cost associated with these treatments. Consequently, mine restoration projects had a success rate of less than one percent (Ross 2000). Modern protocols call for these treatments and success rates have increased dramatically, but ideal treatments may remain prohibitively expensive to be used on very large scales.

The cost of restoration generally represents the most significant barrier to effective revegetation. The climate, price of seed, chemical treatments, mechanical treatments, transportation and labor vary greatly from site to site (Schirmer and Field 2000). Estimates can range from $160 to $43,000 per acre depending on the amount of work and ease of access (Boyd and Davies 2012). Wells tend to be remote, dry and subject to high disturbance, so restoration cannot be expected to be cheap. Farsighted site planning, however, can help reduce costs by taking advantage of seasonal cost reductions, making purchases in bulk, and confining disturbances to well-defined areas of the site (Schirmer and Field, 2000). To stay within budget generally only the restoration techniques which will yield the greatest benefit are implemented, the goal being to produce a functional but sub-ideal product. A perfect site, indistinguishable from an undisturbed native setting, is almost always unattainable under reasonable budgetary constraints (Boyd and Davies 2012).

Time is perhaps the most vital aspect of any revegetation procedure, and yet easily overlooked by the public. To have the assurance that a well site will be restored certainly provides a degree of comfort; however, it is often not understood that the site will not appear healthy and fully restored for years, if not decades. Particularly in arid climates, perennial vegetation establishes slowly and is usually overshadowed by weedy invasives for several years following restoration (Prodgers et al. 2000). On many sites, soil and hydrologic conditions may not favor the vegetation that was planted over long periods of time, rendering it a long-lived cover crop (Prodgers et al. 2000). Weeds that establish may persist for many years without significantly reducing in abundance, regardless of how well the desired species have established (Simmers and Galatowitsch 2010). It is not well know how these restored communities change over long periods of time because most monitoring programs do not persist beyond five years—coincidentally, the same amount of time a mining company must wait to retrieve their bond (Waitakere City Council). Making proactive, meaningful decisions early in the restoration process will carry more weight long-term than reactive decisions, simply because they have more opportunity to tip the balance in favor of desirable outcomes before problems arise (Waitakere City Council). It is important for the concerned citizen to understand that restoration offers no certainty; a site's apparent health can fluctuate over time, and undesirable states may have to be tolerated for prolonged periods.

Returning a site to an essentially undisturbed state is a near impossible task. There are many opportunities for failure, and success should not be expected unconditionally. Society simply must tolerate some degree of damage to the landscape if we expect to extract a resource from it; even when extraction is cheap and efficient, the difficulty and cost of returning the land to a functional state will remain largely unchanged.

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