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Social Costs*

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Abstract

The production of crude oil and natural gas from unconventional reservoirs has become a growth sector within the North American energy industry, and current projections indicate that the production of some of these unconventional fossil fuels will continue accelerating in the foreseeable future. This shift in the energy industry has been accompanied by rising concerns over potential impacts on water resources because producing these fuels is thought to require more water per unit of energy produced than conventional sources and may lead to greater degradation of water quality. In this paper, we address these emerging environmental issues by (a) providing a comprehensive overview of the existing literature on the water quantity and quality implications of producing the main unconventional fossil fuels in North America and (b) characterizing the differences in social costs that arise from the extraction and production of these fuels versus those from conventional fossil fuel production.

1 Introduction

In recent years, the production of crude oil and natural gas from unconventional sources has become a growth sector within the North American energy industry. Current projections indicate that the production of some of these unconventional fossil fuels will continue accelerating in the foreseeable future [33]. This shift in the energy industry has been accompanied by rising concerns over potential impacts on water resources because producing these fuels requires more water per unit of energy produced than conventional sources and may lead to greater degradation of water quality. Damages like these, which are imposed on society by energy production but not realized by those benefiting from that production, are known as *externalities*. In order to ensure net benefits to society from the development of new energy sources, it is important to understand how the externalities of

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unconventional fossil fuel production that affect water differ from those of conventional fossil fuel production, as well as how these differences will ultimately affect individuals and communities.

In this paper, we address these emerging environmental issues by (a) providing a comprehensive overview of the existing literature on the water quantity and quality implications of producing the main unconventional fossil fuels in North America, (b) characterizing differences in the externalities that arise from production of these fuels versus those from conventional fossil fuel production, and (c) applying principles from the environmental economics literature to discuss how these physical externalities may translate into social costs. Our review covers a diverse set of materials including articles published in academic journals and reports released by government agencies, academic institutions, think tanks, industry groups, and environmental organizations.

By focusing on the *extraction* and *processing* phases of four unconventional fossil fuels, this paper fits into the broader literature on the water-energy nexus that examines the many ways in which water and energy resources are linked in today's economy. Other studies in the water-energy nexus literature have analyzed the water resource impacts arising from the *consumption* of fossil fuels. Due to space constraints, we do not discuss consumption externalities in this paper.

The four unconventional fossil fuels covered in this study are shale gas, tight oil, oil sands, and oil shale, none of which can be produced using traditional techniques. For comparative purposes, we also briefly address coal, conventional oil, and conventional natural gas. Our study is geographically limited to the United States and Canada because data and information on water resource impacts are available for these regions. Our overview also omits growing and potentially significant offshore oil and gas sources, which are associated with a very different set of environmental externalities, such as impacts on coastal communities and marine life.

This paper makes two main contributions to the water-energy nexus literature. First, we compare the externalities between conventional and unconventional fuels. Second, this paper provides a synthesis of the various ways in which unconventional fossil fuels are different from their conventional counterparts in the environmental costs they impose on society through water use. As new energy sources continue to develop, identifying these differences can help firms and regulators understand how existing industry practices and energy and environmental policies can be reformulated to reduce the social costs of impacts on water while avoiding unnecessary burdens on fossil fuel producers.

2 Physical externalities

2.1 Unconventional fuels

In this section, we provide a brief description of each type of unconventional fossil fuel and the extraction and processing steps involved. For each fuel, this description is followed by a summary of the water quantity and quality implications of the extraction and processing steps as discussed in the existing literature. In describing impacts on water quantity, we will distinguish between water *withdrawals* and water *consumption*. According to the U.S. Geological Survey, water withdrawal refers to “water removed from the ground or diverted from a surface-water source for use” whereas water consumption refers to “the part of water withdrawn that is evaporated, transpired, incorporated into products or crops, consumed by humans or livestock, or otherwise removed from the immediate water environment” [66].

2.1.1 Shale gas

Shale gas is methane and potentially other gases (e.g. ethane, propane) that occur in fractures and pore spaces between individual mineral grains of shale formations, or can be adsorbed onto (i.e. adhered to the surface of) minerals or organic matter within shale rock. Currently, the most active U.S. shale plays are the Barnett (Texas), Haynesville/Bossier (Louisiana and Texas), Antrim (Michigan), Fayetteville (Arkansas), Marcellus (New York, Pennsylvania, and West Virginia), and New Albany (Illinois, Indiana, and Kentucky) shales. Shale gas production in the United States has grown from about 1 trillion cubic feet per year (Tcf/yr) in 2006 to about 10 Tcf/yr in 2013 [87, 33]. This domestic production is expected to grow to over 16 Tcf/yr in 2040, which would correspond to an increase in the share of shale gas within total U.S. dry gas production from 34 percent in 2011 to 50 percent [33].

The increase in production of shale gas has been spurred by two technological developments: hydraulic fracturing and horizontal drilling. Hydraulic fracturing helps overcome the naturally low permeability of shale formations to extract commercial amounts of gas. The process involves injecting fracturing fluid, usually a water-based fluid mixed with sand and other additives, into the shale formation under high pressure to fracture the rock. This action generates and props open higher permeability pathways in the shale, which improves the flow of trapped gas to a wellbore.

Horizontal drilling involves drilling a well that begins as vertical but is curved to follow the shale seam. This allows more exposure of the formation to the wellbore as these horizontal sections can extend 4,000 to 8,000 feet [51, 80].

Water quantity Much of the water consumed in shale gas production is used in hydraulic fracturing, in which the actual quantities of water involved depend on a number of factors including the geology of the shale, the amount of recoverable gas, and the number of times that fracturing fluid is injected into a given well. Not all of the freshwater use during fracturing is consumptive; estimates suggest that anywhere between 10 and 80 percent of original fracturing fluid volume returns, or “flows back,” to the surface, while the remaining water stays in the formation [4, 51, 126].¹ The flowback may be accompanied by “produced water” or “formation water” that was originally present in the formation. Some flowback and produced water can be recycled, but the eventual waste stream (recycled or not) can be injected in deep underground wells designed to store waste indefinitely (the most frequent approach), treated and discharged as wastewater, or shipped as solid waste to landfills.

In comparing the volume of water consumed in the production of different fossil fuels, it is useful to measure each fuel type’s water intensity, that is, the volume of fresh water consumed per unit of energy in the fuel produced. The minimum water intensity estimate in the literature for shale gas is less than 1 gal/MMBtu (gallons per million British thermal units of energy) while the maximum estimate is 28 gal/MMBtu, with an average across estimates of 7 gal/MMBtu [2, 8, 21, 47, 57, 75, 78, 80, 121].

Water quality The chemical additives in hydraulic fracturing fluid are tailored to particular applications, but tend to consist of proppants (usually sand, which allows fractures to remain open so that gas can escape from the formation), thickeners, friction reducers, biocides, and corrosion inhibitors [51, 126]. Some of these chemicals will return to the surface as part of flowback. In addition, the formation water itself may be millions of years old and include constituents such as salts, volatile organic compounds such as benzene, naturally occurring radioactive material, and heavy metals [74, 107]. One recent analysis of the characteristics of Marcellus shale wastewater found that

¹This range includes estimates provided by James Richenderfer, Deputy Executive Director and Director of Technical Programs, Susquehanna River Basin Commission (personal communication, November 2012).

when barium was detected in produced water before treatment, its median concentration exceeded 200 times the U.S. Environmental Protection Agency's maximum concentration limit of barium in drinking water and was more than 40 times Pennsylvania's wastewater effluent standard [106]. The same study found that concentrations of other pollutants such as bromide, radium-228, and strontium also exceeded federal and state benchmarks for wastewater treatment, suggesting that treatment is indeed necessary [106]. Even the more common constituents in this waste stream, such as salts, create a waste treatment challenge. Average total dissolved solids (TDS) concentrations in shale gas waste range from 800 to 300,000 milligrams per liter (mg/L); the typical ocean water concentration is 35,000 mg/L [95]. These challenges can get worse when these flowback and produced waters are recycled because concentrations of heavy metals and other constituents can rise.

If the flowback is not reused, shale gas operations transfer flowback and produced water off site to a treatment facility or to a deep underground injection well. Temporary storage may take place in lined or unlined evaporation pits, which could potentially lead to seepage into soil or overflow to surface water as contaminated runoff during heavy rain [36, 126]. Moving fracturing chemicals from storage tanks to wellheads and flowback or produced water between wellheads, evaporation pits, and wastewater treatment plants may lead to on-site and off-site spills [4, 80, 126].

In the Marcellus shale play, operators have shipped many millions of gallons of waste to municipal and industrial waste treatment facilities, which are permitted under the Clean Water Act to treat and release effluent to surface water. Researchers have expressed significant concern about the ability of these treatment facilities to remove the contaminants in the shale gas waste stream, particularly high levels of TDS [4, 51, 107]. One study suggests that the treated shale gas waste stream in Pennsylvania causes surface water quality degradation, raising observed chloride levels at downstream water quality monitors in watersheds where the treated effluent is released [90]. An analysis of water samples directly downstream of three Pennsylvania wastewater treatment facilities receiving shale gas waste finds elevated concentrations of barium, strontium, bromides, chlorides, TDS, and benzene [37]. In April 2011, following a study linking treated shale gas waste disposal in the Allegheny River to increases in bromide (another component of TDS) in the city of Pittsburgh's public water supply, even after drinking water treatment [108], the Pennsylvania DEP asked operators in the Marcellus shale to stop shipping waste to facilities that did not ade-

quately remove TDS, including all municipal sewage treatment plants, and some industrial plants. Evidence suggests that this policy change may have reduced water quality impacts from shale gas development [37, 90].

The scale and pace of shale gas development in the region pose a significant challenge to the existing waste treatment capacity. By one estimate, shale gas development in the Marcellus increased total high-TDS wastewater generation in the region by approximately 570 percent between 2004 and 2011 [72]. On top of this, the number of wells drilled in Pennsylvania's portion of the Marcellus is expected to increase from 5,000 in 2011 to about 60,000 wells by 2030 [62]. This current and future waste stream is a significant water quality concern in the Marcellus, particularly because the geology in most of the region is not suitable for deep injection wells; as a result, large quantities of shale gas waste produced in Pennsylvania have been shipped to deep underground injection wells in Ohio [4]. More recently, the U.S. Environmental Protection Agency has started reviewing permits for injection wells in several counties in Pennsylvania.²

Given the scale of new industrial activity represented by shale gas development, another surface water quality concern has to do with stormwater- and erosion-related runoff to nearby water bodies from activities such as site preparation, well completion, and production. The process requires clearing of land, installation of impervious surface on the well pad, new road construction, and very high volumes of truck traffic. Each of these activities, including the persistence of impervious surface between pad construction and restoration of the site once all wells are producing, may increase sedimentation in local water bodies [36, 102, 116]. The first paper in the literature to quantify this risk empirically suggests that the installation of shale gas well pads in Pennsylvania's portion of the Marcellus through 2011 did increase within-watershed downstream concentrations of total suspended solids (TSS) [90]. Even after wells are in production, runoff may be increased relative to the pre-development land cover if the land was previously forested.

Another issue of concern has been the contamination of groundwater with fracturing fluids, other constituents of flowback, and methane and related gases. One route of concern is through pathways created by hydraulic fracturing. One study finds that the probability that a stimulated hydraulic fracture extends vertically beyond 350 meters (1,150 feet) is about 5 percent [25]. However, two

²Steve Platt, Class II Team Leader, U.S. Environmental Protection Agency Region III (personal communication, August 2013).

studies find no geochemical or isotopic evidence of saline fluid contamination from depth associated with drilling and exploration in the Marcellus [118] and Fayetteville [119] shale plays. Similarly, a study in Susquehanna County concludes that methane concentrations in drinking water wells can be explained without the migration of Marcellus shale gas through fractures [79].

Groundwater contaminants could also escape through the multiple layers of cement and steel casing designed to protect shallow groundwater zones that exist in the upper portion of shale wellbores. Incidents have been reported in several states and regulators have found components of fracturing fluid in drinking water wells as well as in blood and urine samples of local residents [98]. Two studies have identified higher natural gas concentrations at drinking water wells that were closer to shale gas wells in northeastern Pennsylvania, suggesting methane contamination of drinking water from shale gas extraction [59, 91]. These studies have been vigorously criticized [24, 104].

2.1.2 Tight oil

Tight oil is found in sedimentary rock formations having very low permeability, such as siltstone and sandstones. The most successful tight oil plays have been the Bakken Formation in North Dakota and Montana and the Eagle Ford Formation in Texas, while California's Monterey shale has the potential to become the most significant U.S. tight oil resource. Development has been rapid, with U.S. production increasing from 540,000 barrels per day in 2008 to 2,300,000 barrels per day in 2013 [33]. Production is projected to peak at a level of 2,810,000 barrels per day in 2020 and decline over time to 2,020,000 barrels per day in 2040 [33].

Of the four unconventional fossil fuels covered in this paper, tight oil is the least studied fuel in the water-energy nexus literature, although it uses the same process as extracting shale gas, namely, injecting large quantities of a fluid composed of water, sand, and chemicals deep underground under high pressure to create fractures in the formation to allow the oil to flow toward a well. Horizontal drilling is also practiced in tight oil production [38]. As a result, the potential impacts of tight oil extraction and processing on water resources may be similar to those for shale gas production [87], except the product itself can damage water resources if spilled. The minimum water intensity estimate in the literature for tight oil is 8.0 gal/MMBtu while the maximum estimate is 21.7 gal/MMBtu, with an average of 14.4 gal/MMBtu [2, 21]. Water used during the refining process is the main reason why water intensity estimates for tight oil are higher than for shale gas, despite

the similarities in extraction technologies.

2.1.3 Oil sands

Oil sands, also referred to as tar sands or bituminous sands, are naturally occurring mixtures of sand, silt, clay, water, and a dense and viscous form of petroleum known as bitumen. Using various technologies, bitumen can be separated from inorganic material and processed for delivery to conventional oil refineries. As of this writing, only Canada commercially exploits bitumen deposits as a source of synthetic crude oil, primarily in the Athabasca, Cold Lake, and Peace River deposits of Alberta. Crude bitumen production in Alberta is expected to hit 605.4 thousand cubic meters per day in 2022, up from 305.5 thousand cubic meters per day in 2012, which corresponds to a projected increase of 98 percent [35].

Bitumen in oil sands cannot be pumped from the ground in its natural state. Deposits near the surface can be recovered by surface mining, using strip mining or open-pit mining techniques. Large powered shovels dig up the oil sands, which are transported by truck to an extraction plant. In the extraction plant, hot water is added to the sand and the resulting slurry is agitated, releasing the bitumen from the oil sands. The bitumen floats to the top of the separation vessel and is then skimmed off. Deeper deposits can be extracted using in situ thermal recovery technology, which includes Steam Assisted Gravity Drainage (SAGD) for thin deposits at 150 to 300 meters in depth and Cyclical Steam Stimulation (CSS) for thick deposits deeper than 300 meters. SAGD operates with a pair of horizontal wells near the base of the oil sands zone, with one well placed approximately 5 meters above the other. Steam is injected into the upper horizontal well, heating the surrounding oil sand deposit and reducing the viscosity of the bitumen. The now fluid bitumen drains by gravity into the lower part of the deposit and is collected and brought up to the surface by the second, lower horizontal well. CSS is a related thermal technique that employs a single well and a discontinuous, three-stage steam injection process that can be repeated cyclically. According to the Energy Resources Conservation Board of Alberta [34], of the remaining established bitumen reserves in Alberta, about 20 percent is recoverable by surface mining methods and the remaining 80 percent is recoverable by in situ methods.

Water quantity When surface mining techniques are used, substantial volumes of water are required during the hot water process that separates the bitumen from the oil sands. In addition, significant quantities of water may be consumed before actual extraction takes place. Forests and wetlands overlying the bitumen deposit (known as “overburden”) must be drained before it can be stripped away. Once the mine pit is excavated, groundwater levels around the mine are lowered by pumping water from the basal aquifer, and the mine pit area is actively drained of runoff and seepage water in order to prevent flooding [86, 122].

Both SAGD and CSS require large volumes of water to generate the steam that is injected into wells. However, after the bitumen is recovered, 90 to 95 percent of the original water can be reused, reducing the net consumption of water [38, 122]. In situ projects can also minimize the consumption of fresh water by mixing it with saline formation water, although this procedure tends to generate large volumes of solid waste [86, 122]. SAGD tends to be less water intensive than CSS because of lower injection pressures [123]. After extraction via mining or in situ methods, water is also required at the upgrading stage in order to produce the hydrogen that remains in the upgraded product.

Several studies provide estimates of the water intensity of energy from oil sands extraction and upgrading. For surface mining, the minimum estimate in the literature is 14 gal/MMBtu while the maximum estimate is 47 gal/MMBtu, with an average of 29 gal/MMBtu [2, 50, 78, 110, 123, 124]. The range of water intensity estimates for CSS is 16 to 31 gal/MMBtu, for an average of 23 gal/MMBtu [78, 123, 124]. The literature suggests that SAGD is the least water-intensive extraction technology, with a range of water intensity estimates from 9 gal/MMBtu to 23 gal/MMBtu, with an average of 16 gal/MMBtu [2, 78, 123, 124]. Note that these water intensity figures may mask the importance of cumulative environmental impacts – that is, the accumulation of impacts from different projects and producers [86]. Cumulative impacts over time may also be significant given that a typical oil sands mine has a 25- to 50-year lifespan and an in situ operation runs on average for 10 to 15 years [18, 49, 122].

Water quality The most common concern in the literature regarding water quality is the risk of the large volumes of tailings that are produced by surface mining operations [1, 48, 49, 50, 85, 110, 122]. Tailings are a slurry of water, residual bitumen, sand, silt and clay particles, and solvent

which is pumped into large settling basins or ponds. The main environmental risk of tailings ponds is the threat of migration of pollutants through groundwater and leaks to the surrounding soil and surface water. Pollutants can potentially include mercury and naphthenic acids [50, 110, 122]. Disturbance of the surface from mining can also generate water quality impacts [113, 115]. Removal of surface vegetation can change runoff patterns and increase erosion by water and wind. In addition, stormwater runoff from disturbed surfaces at mines, surface stockpiles of oil sands, access roads, and supporting facilities can carry contaminants into surface waters.

For in situ extraction methods, the main waste is generated from the treatment of water, which may be saline, prior to its use to generate steam and treatment of produced water prior to recycling. The wastes from these treatment processes may be injected into disposal wells or landfilled. Both of these methods can have harmful impacts, including the potential for salts, acids, hydrocarbon residues, trace metals, and other contaminants to leach into surrounding soils and freshwater aquifers [50, 122]. Two studies find that concentrations of key pollutants were higher in areas downstream of oil sands development than upstream in the Athabasca River and its watershed [64, 65].

There are a series of concerns relating to impacts to groundwater. Groundwater extraction can modify the regional groundwater flow pattern such that fresh water and salt water mix, possibly making aquifers unsuitable for consumption and other freshwater uses [50, 67, 113]. Exploitation of aquifers can also lead to increases in groundwater temperature and pressure that encourage the movement of toxic elements such as heavy metals and naturally occurring arsenic, leading to contamination of aquifers in the oil sands region [50, 67, 85].

2.1.4 Oil shale

Oil shale (not to be confused with shale oil) is a fine-grained sedimentary rock that contains kerogen, a mixture of organic chemical compounds that can be converted to oil and other petroleum products. Whereas oil sands already contain product hydrocarbons, the kerogen in oil shale must be subjected to additional thermochemical decomposition – a process known as pyrolysis – before it can be upgraded to refinery-ready feedstock. Oil shale exists in at least thirty-three countries and a vast majority of the resource is located within the United States [29], especially in Colorado, Utah, and Wyoming [61, 87]. Although oil shale is one of the world’s largest unconventional hydrocarbon

deposits, production technologies are still in the research, development, and demonstration phases. In the most likely case, total production will reach 250,000 barrels per day by 2035; an optimistic scenario puts this number at 1 million barrels per day [87, 42].

The basic technologies for producing oil from oil shale follow a similar pattern as those for oil sands. Using conventional methods, strip and open-pit mining can extract a large portion of the resource, while underground mining can be used for deeper deposits. After mining, the oil shale may be crushed and sent to a retorting facility on the surface for pyrolysis. As with oil sands, there also exist in situ methods in which crude shale oil is extracted directly from the ground rather than mining and bringing the oil shale ore to the surface. These in situ approaches involve generating a cavity in the oil shale deposit by drilling a hole or conducting staged explosions, heating the rock with hot air, steam, or electrical heaters, and collecting the released product. As with bitumen from oil sands, oil from oil shale likely requires further processing and upgrading before it can be sent to refineries.

Water quantity Given the similarity in the technologies used to extract oil sands and oil shale, the environmental concerns for the two energy sources are similar as well. With regard to water quantity, oil shale operations that use mining techniques will need to pump out any groundwater that is intercepted by the mine during initial extraction as well as during extraction of the oil shale [113]. If underground mining techniques are implemented, water may need to be removed from the underground tunnels [42]. These sources of water consumption and diversion have the potential to decrease water levels in aquifers and flows to connected streams. In addition, water is needed for dust control during the extraction, crushing, and transport of mined material and for cooling the spent shale [8].

The U.S. Government Accountability Office [42] indicates that a large source of uncertainty to the range of total water needed to run in situ oil shale operations is the reclamation activities, which may constitute up to half the water needed per barrel of oil produced. The uncertainty is driven by the rinsing of retorted zones, a procedure used to remove residual hydrocarbons and return groundwater to its original quality. Power requirements are also large for in situ operations because of the many heaters used to heat the oil shale over long periods of time; power for these heaters will require water for generating steam and for cooling [38, 26, 42].

The average estimate for water consumption per unit of energy produced from oil shale via in situ retorting is smaller than that for mining with surface retorting, although the range of estimates is wider for in situ methods. For mining, the minimum estimate in the literature is 14 gal/MMBtu while the maximum estimate is 51 gal/MMBtu, with an average of 26 gal/MMBtu [8, 78, 92, 26, 42, 113, 115]. For in situ retorting, the range of water intensity estimates spans 1 gal/MMBtu to 87 gal/MMBtu, with an average of 18 gal/MMBtu [45, 92, 42, 113, 115].

Water quality Water quality impacts of oil shale production are similar to those of oil sands, but they are less well defined given the lack of previous experience with commercial production. After the oil is extracted, spent shale is stored in large piles that are exposed to surface runoff, which could transport sediment, salts, residual hydrocarbons, and other chemicals into surface water [8, 42, 113]. Some of these impacts can be mitigated by diverting runoff from water percolating through spent shale piles into retention ponds, although such ponds would need to be lined properly in order to prevent contamination of underlying shallow aquifers. After operations cease at underground mines, abandoned tunnels would most likely be filled with waste rock, and groundwater flows through these tunnels could affect groundwater quality [42].

Mining and in situ operations can generate produced water from water already in the oil shale formation, which must then be re-injected or held in retention ponds, where it could leak and contaminate surface water and groundwater [1]. Furthermore, heating in the oil shale retorting process can release water previously locked in the rock, which may contain phenols, hydrogen sulfide, and other organics that may be toxic and will require adequate treatment or disposal [46].

2.2 Conventional fuels

2.2.1 Coal

Coal is a major source of energy in the United States, fueling 21 percent of total energy use in 2010 [32]. Although the United States is currently the world's second largest coal producer, production is expected to fall in the near future due to low natural gas prices, rising gasoline prices, lack of growth in electricity demand, competition from renewables, and new emissions requirements. However, after 2015, coal production is expected to grow at an average annual rate of 1 percent at least through 2035 due to increasing electricity demand, rising natural gas prices, production of

synthetic liquids, and exports [58, 32].

Coal is extracted at ground level by strip, auger, open-pit, or mountaintop removal mining techniques or underground by room-and-pillar or longwall mining [28]. Surface mining accounts for 32 percent of total coal production in the United States while underground mining accounts for 68 percent [31]. After mining, coal is often processed by crushing and washing in order to remove impurities and meet environmental regulations [45, 52, 78]. As with oil shale mines, after a coal mine is exhausted and decommissioned, reclamation activities may take place in order to restore the site to its previous state.

Water is consumed before, during, and after the coal extraction and processing stages. Underground and surface mines are often located at least partially below the water table, so water must be pumped out of the working area throughout the duration of the mining activity [52, 28]. The pumped water is usually discharged into creeks and streams, although some operations can capture and treat this water for use in other parts of the mining process. During the extraction process, water is also required for lubricating cutting and drilling equipment and for dust suppression [45, 52, 78, 92, 26]. After extraction, the crushing and washing processes require water [45, 52, 78], and finally, reclamation may require water for revegetation purposes [45, 77, 92]. The minimum water intensity estimate in the literature for coal is 1.5 gal/MMBtu while the maximum estimate is 20.0 gal/MMBtu, with an average of 7.9 gal/MMBtu [77, 78].

Coal mining operations can lead to the contamination of large volumes of water. In addition to the coal itself, mining results in the removal of waste rock from the ground. When this rock is exposed to air and water, contaminating compounds on the surface of the rock can oxidize and leach material into surrounding surface water [45, 52, 71]. Contaminated water from other parts of the production process, such as the water used for dust suppression, crushing, and washing, must be disposed of properly and any runoff from precipitation that falls on piles of coal stored on the surface must be managed [45, 52, 77]. In a poorly remediated underground mine, water may flow through tunnels along rock with chemically active surfaces, while abandoned surface mines can turn into lakes. Oxidation of metal sulfides, often pyrite, in these abandoned mines generates acidity, leading to a problem known as acid mine drainage [60]. Extremely acidic waters have been observed in abandoned underground and surface mining sites [12, 112]. Because new water may continue to flow through abandoned mines and piles of waste rock, a poorly remediated mine may

continue to contaminate water for decades or centuries [11].

2.2.2 Conventional oil

In this section, our definition of conventional oil is limited to production of crude oil from onshore sources in the Lower 48 United States using primary, secondary, or enhanced oil recovery methods. Lower 48 onshore production reached 2.83 million barrels per day in 2010 and is expected to rise slightly until 2020, after which it will fall back to 2.76 million barrels per day in 2035 [32].

The water intensity of oil extraction varies significantly depending on the oil recovery technique that is employed. Primary recovery techniques, which rely on pressure within the reservoir and pumps to drive oil to the surface, have required relatively modest amounts of water. As pressure in the reservoirs falls, secondary methods are applied, which rely on injecting water or some other fluid into the reservoir to increase pressure. Tertiary oil recovery, often referred to as enhanced oil recovery (EOR), is typically conducted toward the end of an oilfield's life. EOR works by altering the flow properties of the oil and rock-fluid interactions in the reservoir to improve oil movement [111]. In the United States, almost all crude oil production employs either secondary recovery or EOR techniques (79.7 percent and 20.1 percent of total output, respectively). The most common EOR techniques are CO₂ injection and steam injection, which make up over 80 percent of U.S. output that employs EOR [78].

Water is used extensively in secondary recovery during the water flooding process [45, 77, 78]. In addition, both CO₂ and steam injection methods in EOR require substantial quantities of water [2, 45, 78]. Finally, refining the oil once it is extracted requires water for generating steam and for cooling purposes [2, 45, 78, 92]. For primary and secondary recovery, the minimum water intensity estimate in the literature is 7.8 gal/MMBtu while the maximum estimate is 75.0 gal/MMBtu, with an average across estimates of 33.2 gal/MMBtu [44, 45, 77, 78, 123]. For EOR, the minimum water intensity estimate in the literature is 34.8 gal/MMBtu while the maximum estimate is 196.5 gal/MMBtu, with an average of 96.1 gal/MMBtu [45, 78].

As with drilling for unconventional fossil fuels, significant quantities of produced water can be extracted with conventional oil. This produced water can be of varying quality, even nearly fresh, and suitable for injecting back into the producing well to enhance production. Produced water higher in dissolved solids and other constituents may also be disposed of by injection into other for-

mations that lie far below usable groundwater resources [26]. Other water quality concerns include potential leakage of liquid wastes to surface and groundwater [123], while oil refinery effluents may also contain toxic substances and organic compounds [117].

2.2.3 Conventional natural gas

In 2010, onshore non-associated and associated-dissolved gas production in the Lower 48 United States was equal to 6.0 trillion cubic feet per year, excluding shale gas, coal-bed methane, and tight gas. This production quantity is expected to decrease to 3.4 trillion cubic feet per year by 2035 due to the rapid expansion of shale gas production during the same period. As a result, the share of conventional natural gas within total natural gas production in the United States will fall from 32 percent to 14 percent [32].

Set against the energy content of the gas ultimately recovered from the production well, conventional natural gas extraction consumes relatively little water. Small quantities are required during the drilling phase to lubricate and cool the drill bit [52, 78]. Natural gas processing also requires some water for removing liquid hydrocarbons, acid gases, carbon dioxide, and water vapor [2, 52, 78]. Estimates in the literature for the water intensity of conventional natural gas production range from a minimum of zero gal/MMBtu to a maximum of 3.0 gal/MMBtu, with an average value of 1.8 gal/MMBtu [44, 77, 92, 26].

Potential impacts to water quality for conventional natural gas extraction and processing are similar to those for conventional oil production. Water that was used to lubricate and cool the drill bit may contain toxins, and as a result may need to be injected underground or treated and then and reused or released [52]. Produced water from conventional gas wells can contain oil or grease, high concentrations of salts, naturally occurring radioactive material, and other organic or inorganic compounds that may lead to toxicity if not properly contained or treated [74, 114].

2.3 Summary of physical externalities

Analyzing the water intensity estimates for various fuels is one way to compare the water scarcity implications of conventional versus unconventional fossil fuels. Figure 1 illustrates the ranges and averages of water intensity estimates available in the water-energy nexus literature for the conventional and unconventional fossil fuels addressed in this report. Whenever possible, we provide

a separate average and range for different extraction technologies.

Several insights arise from Figure 1. First, some of the energy sources exhibit very wide ranges of estimated water intensities. For example, conventional oil and oil shale with in situ retort have minimum and maximum estimates that are almost an order of magnitude apart. These wide ranges highlight the importance of idiosyncratic factors in individual applications, such as local geology, in determining the water intensity of a given fuel type and extraction technology. Second, while conventional natural gas is the least water-intensive fuel, Figure 1 illustrates that, on average, shale gas is the next-best fuel alternative to conventional gas in terms of water intensity. Therefore, to the extent that the projected growth in shale gas production can offset oil production, it is possible that total water use in the future may be less than what would have occurred in the absence of shale gas development.³ Third, oil production from oil sands and oil shale consumes less water per unit energy than conventional oil production, especially if the conventional oil is being extracted using EOR methods. Given that almost 20 percent of current oil production in the United States employs EOR techniques, future expansion of oil sands and oil shale may help reduce the water footprint of economic sectors that may not be able to readily switch to natural gas or renewables as a fuel. Finally, in situ technologies for extracting oil from oil sands and oil shale are less water intensive than their corresponding mining methods.

While water intensity is a useful measure to compare different fuels, water scarcity is ultimately determined by the availability of total quantities of water in specific locations for their various uses. Therefore, it is also important to identify cumulative water impacts, that is, the total volume of water consumed across users that rely on a water resource over time. Improvements in the water intensity of energy production may not be meaningful if significant growth in overall production increases the total quantity of water consumed from an aquifer or surface water body [85].

Furthermore, the spatial scale used to calculate overall net water use can make a large difference in defining the scarcity of water. For example, state-wide figures for water use in Texas show that less than 1 percent is associated with shale gas production, which is minor compared to consumptive irrigation (56 percent) and municipal use (26 percent) [89]. However, the share of water use

³Note, however, that for shale gas production to significantly offset oil production, natural gas would need to be used more extensively in the transport sector; for this reason, unconventional gas is much more likely to displace coal than oil in the North American context [16]. The water intensity tradeoffs between coal and shale gas are less clear (Figure 1).

measurement at the county level can be dramatically different; the Texas Water Development Board predicts that the future share of water use going to shale gas production in La Salle County, for instance, could reach 40 percent [41]. Some studies warn that new energy development is taking place in historically arid places [89, 113] while other studies claim that it is taking place in areas with relatively more precipitation [51]. Because both these claims can be substantiated by a visual comparison of national source rock formation maps and water scarcity maps, a more rigorous, quantitative study is needed to quantify the risk of water scarcity in specific locations.

Regarding water quality, although there are a large number of pathways through which fossil fuel development can contaminate groundwater and surface water, these impacts can be categorized into four types: (1) impacts from improperly contained tailings ponds and evaporation pits used for wastewater disposal, (2) impacts from site clearing and preparation prior to fuel extraction, (3) surface water pollution from inadequate wastewater treatment, and (4) groundwater pollution from leaks and spills of chemicals, flowback, or produced water. Our overview has found that these water quality impacts are associated with both conventional and unconventional fossil fuels. However, unconventional fuel extraction and processing introduce previously unknown and poorly understood contaminant pathways and are thus associated with greater uncertainty and risk compared to conventional fuels. Uncertainty and risk are further magnified by the more rapid pace of expansion in the shale oil/gas and oil sands industries relative to coal, conventional oil, and conventional gas, for which the potential impacts on water quality are better understood.

3 Social costs of impacts on water resources

The previous two sections of this report described the physical externalities related to water resources that are caused by the extraction and processing of unconventional and conventional fossil fuels. In this section, we discuss the different ways in which these physical externalities can lead to social costs, as quantified in previous economic studies.

3.1 Increased surface water and groundwater scarcity

One likely cost to society of increased unconventional fossil fuel production is imposed through heightened water scarcity, which impedes productive activities that require water as an input. For

instance, as the exploitation of a groundwater or surface water resource continues, diminished stocks and flows can make water a limiting factor for unconventional fossil fuel producers [45, 77, 85, 42, 123]. These costs may also be imposed on users other than energy producers who are exploiting the same water resource, such as municipal water suppliers, farmers and ranchers, and recreational users [17, 20, 105]. Some of these competing water uses can be unique to specific fuel sources and geographic locations, such as the needs of aboriginal communities along the Athabasca River and close to oil sands operations [49]. The more scarce the resource becomes, the higher is the unit value of remaining water – thus, costs related to scarcity may increase over time with the scale of unconventional energy development.

The social cost of water use for unconventional fossil fuel development is an opportunity cost – water withdrawn to develop these resources produces significant economic value, but it removes water from rivers, streams, and aquifers that could otherwise support other uses, either in diversion or instream. If water were traded in markets, and prices represented the full social cost of consumptive use, the marginal value of water use for unconventional fossil fuel development and all other uses would be equated, and the quantity of water used for each purpose would be dynamically efficient. Water markets are growing in the western United States [15], and the social cost of water withdrawals for unconventional fossil fuel development could be mitigated by the ability to lease and/or purchase water rights from other users. A small number of trades have already taken place between farmers and energy developers in North Dakota, Colorado, and Utah [120]. However, most of the raw water that operators withdraw from surface and groundwater sources is not priced – firms incur pumping, storage, and transportation costs, but pay nothing for the water itself.

There is a substantial literature that quantifies the marginal value of surface water left instream for recreation, riparian and wetlands restoration, and other purposes. In some cases, economists have compared these values to estimates of the marginal value of water used for irrigation, often the largest competitor for scarce water. In many arid regions, the marginal value of water left instream to support public goods may exceed its value in irrigation and other uses [22]. Estimating the value of instream water for recreational use or ecosystem maintenance often requires non-market methods such as recreational demand models, contingent valuation (CV), and hedonic housing models.

Several studies have used CV surveys to estimate the benefits to local populations of resum-

ing or increasing flows in dry or degraded rivers, which may affect several ecosystem services.⁴ Overall, these studies have found that local populations may have substantial willingness to pay for restoring these flows. For example, studies estimate a favorable benefit/cost ratio for riparian restoration projects along the Little Tennessee River in North Carolina [54], and net benefits to purchasing water leases and farmland easements to restore a section of the Platte River near Denver, Colorado [70]. Hedonic housing studies in the United States suggest that homeowners in arid regions have significant willingness to pay for proximity to healthy riparian systems, supported by sufficient water flows [6, 7].⁵

The recreational benefits of increasing instream flow in surface water have also been estimated. Estimates for the United States suggest that the marginal value of water for local and downstream fishing exceeds the marginal value of water for irrigation in 51 of the 67 river basins with significant irrigation, but the values are highest in the arid Southwest, where the effects on fishing of marginal changes in streamflow are greatest [53]. One study found that increasing water supplies to 14 wildlife management areas in California's San Joaquin Valley, which would improve wildlife viewing, fishing, and waterfowl hunting, would have estimated benefits that exceed the marginal value of water for agriculture in the region for the same period [22].

In order to understand the tradeoffs being made when water is withdrawn for unconventional fossil fuel development, the benefits of those withdrawals would need to be estimated, and compared to new estimates of their opportunity cost for each particular region. The true opportunity cost of energy development depends on the level of demand for water in other uses, which may, itself, depend on the scale of energy development (recreational demand, for example, may decline if the landscape is dominated by energy facilities). Energy development may compete very well for scarce water. One study suggests that the optimal allocation of water between agriculture and oil development in Alberta may even involve a temporary dormancy period for agriculture, during peak oil development, if exploitable oil stocks are sufficiently large [43]. As noted above, however, there is significant evidence that leaving water in rivers and streams generates economic value in many locations. This opportunity cost is the most obvious concern when it comes to competition

⁴CV is a survey method in which economists elicit respondents' willingness to pay for changes in the status quo (such as an increase in instream flow) by asking carefully structured questions.

⁵Hedonic housing models statistically estimate the portion of home prices that can be attributed to a particular characteristic, such as proximity to healthy rivers, controlling for other characteristics.

with energy operators for scarce water, because there are generally no markets for these services (with the partial exception of recreational uses), and they have historically been underrepresented in public policy decisions at the state and federal levels regarding water allocation.

3.2 Contamination of drinking water

Water contamination can lead to a variety of social costs, of which the impacts on drinking water are likely to be the most important. The economic net benefits of safe drinking water are demonstrably very large [23], and the economic damages associated with any increased human morbidity or mortality through this pathway would be of great concern. However, households consuming piped water from drinking water treatment plants (whether the source is surface water or groundwater) are protected from such impacts, provided that treatment techniques and practices are sufficient to remove any potential contaminants related to unconventional fossil fuel production. In contrast, households consuming groundwater directly are potentially more vulnerable to health impacts from unconventional fossil fuel development.

However, whether hydraulic fracturing or other extraction methods directly cause drinking water contamination is an ongoing debate. The perception of risks to drinking water supplies may be widespread; a hedonic property study suggests that perceived groundwater risk related to nearby gas wells reduces property values by up to 24 percent [83]. However, actual impacts to groundwater wells, aside from methane, have not been demonstrated in the literature. To estimate the actual (as opposed to perceived) social costs of drinking water impacts, the impacts, themselves, would first need to be carefully quantified. Then, to monetize these impacts, economists can employ a variety of methods to obtain estimates of the willingness to pay to reduce any potential damages. A recent study [10] used contingent valuation methods to estimate the value residents of the Susquehanna Valley place on additional safety measures that would protect the local watershed from contamination by the shale gas industry. Results show that households are willing to pay an average of \$10.46 per month for those additional safety measures. This is in line with previous empirical studies on the value that people place on the availability of clean (not necessarily drinking) water [19, 30, 69]. If impacts to drinking water increase treatment costs for public suppliers or private households on well water, these cost increases would need to be included in estimates of the social costs of unconventional fossil fuel development, as well.

3.3 Contamination of water used for other purposes

There is some concern that contamination of water resulting from unconventional fossil fuel production may lead to losses in the agricultural sector, particularly for livestock producers. A study based on interviews with animal owners near gas drilling operations in Colorado, Louisiana, New York, Ohio, Pennsylvania, and Texas identified potential links of animal health problems to contaminated water, including exposure to hydraulic fracturing fluid and wastewater [5]. The study also identified reproductive, neurological, and other health issues in companion animals, which may convey significant losses to their owners. In 2010, the Pennsylvania Department of Agriculture quarantined cattle from a Tioga County farm after a number of cows came into contact with a holding pond that collected flowback water from a nearby hydraulic fracturing site [93]. As a result, there is potential for social costs to be imposed on agriculture from livestock deaths and health damages that may make livestock unsuitable for sale. Losses to agriculture may also come about from negative effects on land or irrigation water quality, or consumer resistance to food grown near unconventional oil and gas wells [94].

Water quality degradation may also generate significant economic damages through impacts on recreation and other water uses. Economists have demonstrated that these uses have significant value. General estimates of the annual benefits generated by the U.S. Clean Water Act, most of them related to recreation, are in the range of \$22 to \$29 billion, in 1990 dollars [19, 39]. There are also many estimates of the value of water quality improvements on a smaller scale. For example, economists have shown that residential waterfront land prices increase with reductions in bacterial contamination [69], and that consumers have significant willingness to pay for the improvements in coastal water quality resulting from reductions in nutrient runoff [82].

Lab experiments have shown that the water in oil sands tailings ponds can be acutely toxic to aquatic life [55] and to wild mammals with repeated exposure [101]. In addition to naphthenic acids, high concentrations of TSS, TDS, and bitumen, as well as low dissolved oxygen levels, may also contribute to the toxicity of the water [73]. Studies have also observed wildlife impacts from the production of fuels from resources other than oil sands. Field inspections of separation pits and evaporation ponds at oil and natural gas facilities in Wyoming identified significant mortality incidents in grebes and waterfowl, particularly at older facilities permitted in the 1980s [99]. It may

be in society's interest to reduce some of these potential impacts if wildlife generates significant value to individuals. In other contexts, economists have identified recreational fishing benefits of water pollution abatement [76, 81]. Furthermore, starting with the early research of Krutilla [68], wildlife is thought to produce economic value to users not actually "using" wildlife but who, nevertheless, have an interest in preserving it [13].

3.4 Other social costs

One indirect way by which water use in unconventional fossil fuel production can generate social costs is through earthquakes; pumping fluids into or out of the earth has the potential to cause "induced seismic events." A recent study published by the National Research Council [88] found that the process of hydraulic fracturing as presently implemented for shale gas development does not pose high risk for triggering earthquakes that can be felt. However, several widely publicized seismic events over this threshold have occurred near injection wells disposing of hydraulic fracturing fluid wastes. A study in north-central Arkansas found close spatial and temporal correlations between injection at waste disposal wells and increases in the rate of earthquakes [56]. Similarly, a two-year survey of injection well locations and earthquake activity in the Barnett Shale detected a series of earthquakes that were unlikely to all be of natural origin [40]. The literature on the economics of natural hazards has shown that earthquake risks can impose costs on individuals. Studies have shown that earthquake and volcano hazard notices can negatively affect local investment and lead to a decrease in housing rents and the market value of homes [9, 84].

For gas and oil drilling facilities that are far away from fresh water sources or produced water disposal sites, significant quantities of freshwater or wastewater may need be trucked in and out of the area [4, 80]. Several survey studies for counties located near the Barnett Shale have found that increased truck traffic due to transportation of water for the hydraulic fracturing process is one of the top public safety concerns amongst key informants and the general population [3, 109]. In addition to increased truck traffic, impacts to water resources may degrade the experience of visitors who arrive for tourism purposes [27]. As a result, vehicular traffic and tourism impacts may be two more indirect pathways through which the link between unconventional fossil fuel production and water resources may impose additional costs on local communities.

4 How are unconventional fuels different?

In this section, we describe some of the reasons why the social costs of unconventional fossil fuel production may differ from those of conventional fossil fuel production. We identify these reasons because they may explain why differences in the social costs of conventional and unconventional fossil fuel development may be greater than what the differences in the physical externalities may suggest.

4.1 The rapid pace of development

A distinctive feature of unconventional fossil fuel development in North America is its rapid growth, both in recent years and in future projections. This rapid pace of development may have important consequences if society is not able to manage the associated environmental costs in the same time frame. Regulators in many states have followed closely the growth of these new industries in their jurisdictions, but constraints on available funds, personnel, and experience may lead to delays in monitoring and quantifying externalities related to water resources. The pace of development also may mean that affected parties, such as residents with contaminated well water or environmental groups with interest in local ecological habitats, may have difficulty organizing and mobilizing themselves in order to work with regulators and energy producers to resolve these issues.

In the existing literature, lack of knowledge and data are significant sources of uncertainty in defining both the physical externalities and social costs of unconventional fossil fuel development on water resources. Developing policies to address the social costs of local energy development requires an understanding of the physical externalities; scientific knowledge regarding the causal impacts of particular extraction and processing activities on water quality and quantity is necessary for a firm to alter its practices to reduce impacts, or for a policymaker to decide which kind of regulation would be most effective. Accurate information on both the affected water resource and the relevant energy resource is important. For example, lack of reliable estimates on the ultimately recoverable energy resource translates to unreliable estimates on future expected water consumption [78].

Another set of issues that arises from the rapid development of unconventional fossil fuel operations is related to the technology used to extract and process the fuel. Many of the characteristics of the technologies used by producers are relatively new and can therefore be claimed as proprietary

information. For example, the chemical composition of hydraulic fracturing fluid used in shale gas extraction is closely guarded by producers although fifteen U.S. states now require public disclosure of these substances, as do, in a limited way and only after drilling is finished, the draft U.S. Department of Interior rules for hydraulic fracturing operations on public lands [98, 100, 107]. From a regulator’s perspective, there is a tension between the desire to encourage research and development by allowing firms to temporarily withhold trade secrets in order to recoup earlier investments and the desire to make individuals and communities surrounding energy operations aware of potential risks they face.

4.2 Adaptation of local communities

Another distinguishing feature of unconventional fossil fuel production over the last several years is that it is often taking place in regions with little previous history of energy development. The literature suggests that the consequences of this unfamiliarity for social costs are ambiguous. Social costs of water resource impacts may be higher in these locations because the physical infrastructure and regulatory framework necessary to manage the risks of fossil fuel development may not be in place. Shale gas production in the Marcellus, which represents 35 to 40 percent of the U.S. shale resource, is a primary concern in this respect [80]. Texas has the longest history of shale gas production, and impacts on water quantity and quality could serve as a guide for production in younger plays in the U.S. [78, 89].

However, some studies suggest that a longer history of energy development may lead to a perception of higher social costs since residents have previous experience with the negative impacts of development [3, 14, 109]. For example, Brasier et al. [14] argue that residents of Pennsylvania counties on the Marcellus shale express concern about surface and groundwater quality impacts of shale gas production during interviews because of their previous experience with acid coal mine drainage and associated acidification of streams. Communities near energy production facilities that have reached a more mature phase are also more likely to face constraints in water availability and wastewater disposal [125]. These added pressures to local water resources may translate into higher social costs to surrounding communities.

Several studies have documented how local communities are facing difficulty in adapting to rapidly changing local conditions due to nearby unconventional fossil fuel development [14, 96, 103].

Most of these conflicts are related to sudden population growth and increased economic output (commonly referred to as the “boomtown effect”). However, some of these disruptions are associated with local water resource problems, including road building that has not kept pace with increased truck traffic from transportation of fresh water and wastewater.

Total social costs of drinking water impacts will depend on the number of affected individuals, so the population density in the vicinity of unconventional fossil fuel development is an important factor. Total social costs may be low in relatively uninhabited areas such as northern Alberta, where most oil sands production takes place. In contrast, shale gas development activity in the Marcellus is upstream of drinking water supplies for major population centers including New York City, Pittsburgh, and Philadelphia. An equivalent increase in water contamination due to energy production could thus have a larger aggregate impact in the Marcellus than in Alberta.

4.3 Timing issues

Several studies point out that the interaction between unconventional fossil fuel production and water resources is distinguished by timing issues that don’t exist for conventional fossil fuels. In shale gas extraction, most of the water consumption occurs within one to five days during the hydraulic fracturing process. As a result, large quantities of water are required over relatively short periods of time, and very little water may be required during the time when gas is actually being produced [2, 78, 80]. For oil sands production in Alberta, studies warn that surface water impacts on the Athabasca River are particularly critical during the winter months, when flow can drop to less than 15 percent of its average peak flow in July [110, 122].

These examples show that some of the social costs of unconventional fossil fuel production are not necessarily constant over time and may instead be focused within short periods of time. This has implications for firms’ practices and for regulation in that a time varying policy may help reduce some of these social costs while allowing development of the resource. For example, in April 2012, due to low stream flows following a winter with little snow and a spring with below-average rainfall, the Susquehanna River Basin Commission triggered water withdrawal stoppages for 10 companies developing or operating shale gas wells in Pennsylvania. However, this suspension of water withdrawals had a limited impact on gas production in the region because flows of natural gas at wells that were already producing were able to continue [97]. Steps could also be taken to

utilize excess water during peak seasonal runoff [126]. In areas where there are distinct wet and dry seasons, abundant water in surface streams and groundwater supplies during the wet season could be stored for use during the dry season when these resources are depleted.

4.4 Potential technological improvements

While the emergence of unconventional fossil fuels poses many challenges, it also provides many opportunities. Thus, a distinguishing feature of unconventional fossil fuels is that its current and projected growth allows for innovative technological and policy solutions that may be developed in order to reduce the social costs of production.

The literature cites many opportunities for reducing net water consumption by reusing or recycling produced water. Increased reuse of flowback and produced water not only reduces the initial required quantity of water for production but also reduces the volume of contaminated water that must be treated and disposed of. Oil sands production using SAGD technology can already reuse a large proportion (90 to 95 percent) of the water that is used to generate the steam that is injected [38, 122]. Technology and methods to reuse flowback in shale gas operations are being developed, although the benefits of reuse will be smaller than for SAGD since flowback in shale gas development comprises a smaller proportion of the water injected. One potential drawback is that in some cases the treatment process that converts produced water to a reusable quality may generate large amounts of solid waste, which must be properly addressed. Another drawback is that the recycling may concentrate the wastes, making any spill more dangerous.

In addition to reuse and recycling, there are several opportunities to develop technologies that reduce initial freshwater use. One opportunity is to develop technology that allows use of saline groundwater, thus avoiding the exploitation of freshwater aquifers or streams. In fact, almost all SAGD projects in the Athabasca oil sands deposits already use some fresh groundwater mixed with saline groundwater from deeper formations. The oil sands industry is also testing experimental methods known as Vapor Extraction Process (VAPEX), which uses hydrocarbon solvents instead of steam to dilute bitumen, and Toe to Heel Air Injection (THAI), which involves a vertical air injection well and a horizontal production well. Ongoing testing is also occurring for alternatives to hydraulic fracturing; one such series of tests has used liquefied petroleum gas (LPG) to generate fractures in the shale and deliver proppants into the fractures, where the process generates no

wastewater since all of the LPG is recaptured back up the well [63].

5 Conclusion

Current and expected future growth of the unconventional fossil fuel industry in North America has heightened concerns regarding potential impacts of energy development on water quantity and quality. In this paper, we have provided an overview of the existing literature on the water resource implications of extracting and processing shale gas, tight oil, oil sands, and oil shale. Our paper has also referred to studies in the environmental and natural resource economics literature that help link the physical impacts on water resources to costs that are borne by society. We contribute to the water-energy nexus literature by providing a comparison of water impacts across different fuel types and by identifying reasons why the social costs of unconventional fossil fuel production can be different from those that arise from the production of conventional fossil fuels.

This overview of the literature leads to several key findings. First, we find that the water quantity impacts of unconventional fossil fuels are, on average, not significantly worse than for conventional fossil fuels. However, the literature does indicate that the specific location and timing of water use for fuel production matter; as a result, significant localized negative impacts are possible. Second, we find that the water quality concerns associated with unconventional fossil fuels are likely to be more serious than water quantity concerns and more serious for the unconventional than the conventional fuels. The new extraction and processing technologies that characterize unconventional fossil fuel production introduce previously unknown and poorly understood contaminant pathways, while the rapid pace of expansion in the industry adds significant uncertainty regarding potential impacts on water quality. Third, although there are few existing studies that directly quantify the social costs and benefits of unconventional fossil fuel production, there are a large number of studies in the economics literature that can help identify where these costs and benefits are generated and how large they might be, given an estimate of the burdens such development creates. Our fourth and final finding is that unconventional fossil fuel production exhibits characteristics that may increase or decrease the social costs of water impacts relative to conventional fuels. These characteristics include the rapid pace of current and expected growth in production levels, the differential ability of communities to adapt to nearby energy development, unique timing

issues in the use of water in production, and the potential for new technologies that may allow for more sustainable paths of water use.

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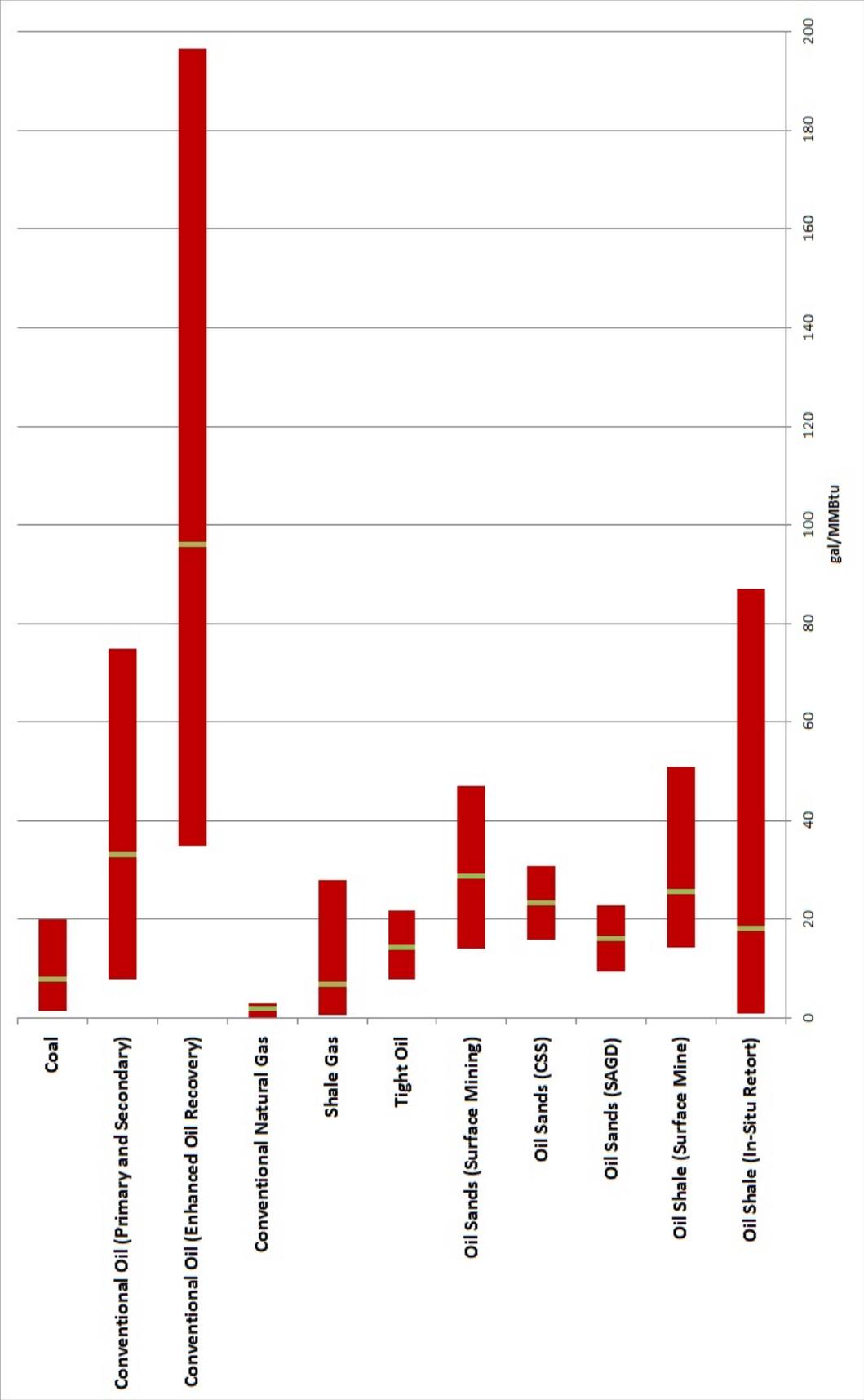


Figure 1: Ranges and averages of water intensity estimates (consumptive use) available in the existing water-energy nexus literature.