Consumptive Water Use in Bioethanol and Petroleum Gasoline Pathways

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Abstract

Energy production requires substantial water input. Biofuel feedstocks like corn, switchgrass, and agricultural residues need water for growth and conversion to bioethanol. Likewise, petroleum feedstocks like crude oil and oil sands require large volumes of water for drilling, extraction and conversion into refined products. Water management has become a key feature of existing projects and a potential issue in new ones.

This paper examines the growing issue of water use in energy production by characterizing current consumptive water use in liquid fuel production. "Consumptive water use" is defined as the sum total of process water input less water output that is recycled and reused for the process.[1] The estimate applies to surface and groundwater sources but does not include precipitation. Water requirements are evaluated for five fuel pathways: bioethanol from corn, bioethanol from cellulosic feedstocks, gasoline from Canadian oil sands, gasoline from Saudi Arabian crude oil, and gasoline from conventional crude oil produced from U.S. onshore wells. Regional variations and historic trends are noted, as are opportunities to reduce water use.

[1] For biofuel feedstocks, consumptive water use is further defined as the water that is incorporated into the crop or lost to evapotranspiration (ET), because it cannot be reused for another purpose in the immediate vicinity (USDA NASS 2007).

Introduction

With rising public awareness that U.S. dependence on foreign oil reduces energy security, retards economic growth and exacerbates climate change, alternative and renewable fuels are gaining increased visibility and support. Venture capitalists are investing in new fuel and vehicle technologies. States and localities are adopting renewable fuel mandates, discussing carbon budgets and subsidizing industry startups. And, the 2007 *Energy Independence and Security Act* (EISA) is committing this country to produce 36 billion gal of renewable fuels by 2022 — 16 billion gal of cellulosic ethanol, 15 billion gal of corn ethanol and 5 billion gal of biodiesel and other advanced biofuels. As a result of these actions, biofuels production has grown at an unprecedented rate.

At the same time, the U.S. is importing more unconventional crude oil, much of it derived from Canadian oil sands, and extracting a growing share of domestic crude using secondary and tertiary recovery technologies. All three of these fuel pathways — ethanol from biological feedstocks, gasoline from oil sands, and gasoline from secondary recovery in mature oil wells — require substantial water input and raise important sustainability questions. From time immemorial, water has nurtured human populations and supported their activities. Where plentiful, it has been taken for granted; where scarce it has been sought after and fought for. Few have appreciated that overuse or misuse of this precious resource can lead to serious and irreversible consequences. Today, however, a growing appreciation of the potential for truly catastrophic consequences is producing a dramatic change in business priorities. Sustainability considerations are becoming not only key inputs in business decisions but decisive factors affecting competition worldwide. In this context, a thorough examination of water consumption in biofuel and petroleum development is a critical input to policy development. This paper is a key part of that examination. It asks the following questions:

- How much water is consumed to produce a gal of ethanol in the United States?
- How much water is consumed to produce a gal of gasoline from conventional domestic or imported petroleum and from oil sands?
- What are the regional variations (if any) in water use to produce ethanol and petroleum gasoline?

Scope

This paper examines water use for the production of energy feedstocks and fuels from the perspective of lifecycle analysis. Fuel lifecycles include resource extraction (feedstock farming), feedstock transportation, fuel production, fuel transportation, and operation of a vehicle on the fuel. In this paper we focus on two major steps in that life cycle — feedstock production (corn or switchgrass farming, oil extraction and production) and fuel processing/production (ethanol production and oil refining). For corn ethanol,[2] we focus on three of the 10 farm production regions defined by the U.S. Department of Agriculture (USDA, see Figure 1). They are Region 5 (Iowa, Indiana, Illinois, Ohio, and Missouri), Region 6 (Minnesota, Wisconsin, and Michigan), and Region 7 (North Dakota, South Dakota, Nebraska, and Kansas). These regions consistently account for 88 percent of U.S. corn production (USDA–NASS 2007) and 95 percent of U.S.

[2] Unless otherwise noted, "ethanol" refers to denatured ethanol.

ethanol production (RFA 2007). We examine corn ethanol produced via dry milling and cellulosic ethanol produced via biochemical and thermochemical conversion technologies.

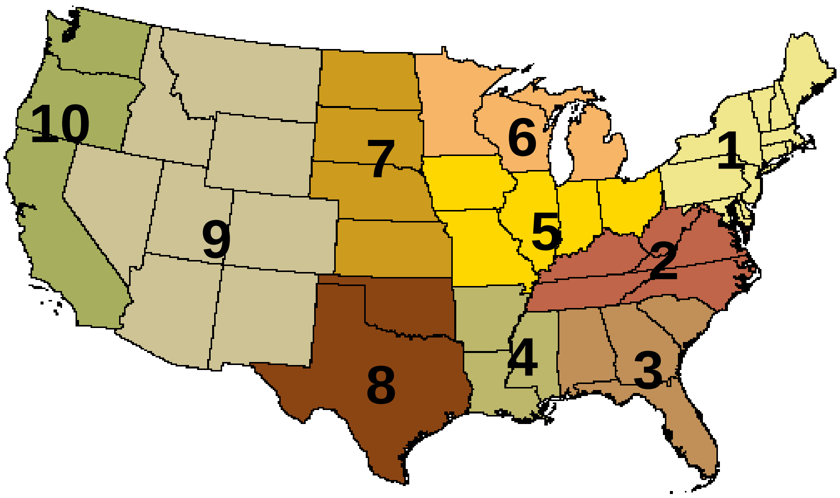

Figure 1. USDA Farm Production Regions

For domestic production of petroleum gasoline, we focus on three Petroleum Administration for Defense Districts (PADDs II, III and V, see Figure 2), which together represent 90 percent of U.S. onshore crude production and 81 percent of refinery output (EIA 2008a). PADD II includes the states of Oklahoma, Kentucky and Tennessee in addition to USDA Regions 5, 6 and 7; PADD III includes Texas, New Mexico, Arkansas, Louisiana, Mississippi and Alabama; PADD V includes California, Arizona, Nevada, Oregon and Washington. We estimate consumptive water use for onshore crude exploration and production (E&P) and oil refining. We consider primary, secondary and tertiary technologies and produced water re-injection for the recovery of crude oil, and calculate typical consumptive water use as a weighted average.

Figure 2. Petroleum Administration for Defense Districts

For production of petroleum gasoline from Canadian oil sands or from Saudi Arabian crude oil, we focus on the Athabasca, Cold Lake, and Peace River sites in Alberta (which represent 43 percent of Canadian oil production and 100 percent of Canadian oil sands production) and the Ghawar field (which represents 52 percent of Saudi Arabian oil production), respectively. Together, Saudi crude oil and Canadian oil sands accounted for 23 percent of U.S. crude oil imports in 2005 (EIA 2007a).

Methodology

In order to focus on the products and processes most likely to affect water consumption, representative feedstocks, fuel pathways and regions were specified for each liquid fuel. Since data relevant to agricultural production and water resources (including information on precipitation, surface and groundwater and production of "produced water" (PW) in oilfield operations) are collected by state, this became the natural basis for analysis. However, since not all states are relevant to this analysis, and detailed state-level analyses are beyond the scope of this study, state data are aggregated to regional estimates.

Process-level data on water use by fuel production technology are obtained from the literature and weighted by estimated market shares to derive averages for each lifecycle stage. Variations among regions are identified, characterized by a range of data values, and compared.

Since liquid fuel industries typically use a volume-based product metric, results are expressed as gal of water consumed per gal of product fuel. This analysis is intended to derive unit estimates of water consumed by major fuel production lifecycle stage, not total water use. In the future, the inventory compiled for this effort can be used to develop net water consumption LCAs of liquid motor fuels, as well as other regional and fuel-specific analyses.

Water and Biofuel Feedstocks

Water use for plant growth is an intrinsic part of the hydrologic cycle (water cycle). As illustrated in Figure 3, rainfall that precipitates on the ground follows several paths: absorption by plants, percolation into the soil, surface runoff to waterways, and infiltration into the underlying aquifer and groundwater.

Surface streams receive water from direct precipitation, surface runoff and, in some cases, interflow from water tables. A water table that is connected to a surface stream is able to receive input from or feed to the stream. If groundwater is located in a confined aquifer, however, it is mostly isolated from surface streams and its withdrawal represents a net water loss. In this case, water can be considered a non-renewable resource and overconsumption could lead to resource depletion.

Transpiration accounts for the movement of water within plants and the loss of water vapor through leaves. Water is also lost to the air by evaporation from soils and streams. The sum of transpiration and evaporation, termed evapotranspiration (ET), describes the water movement from plant, soil, and land surface to the atmosphere. The water that is incorporated into plants or lost to evapotranspiration is called consumptive or net water use because it cannot be reused for another purpose in the immediate vicinity (NASS 2007). This paper focuses on consumptive water use from irrigation. It does not estimate crop ET directly, but instead examines net irrigation water use at an aggregate level. Precipitation is only included insofar as it affects the need for irrigation, the primary focus of this analysis.

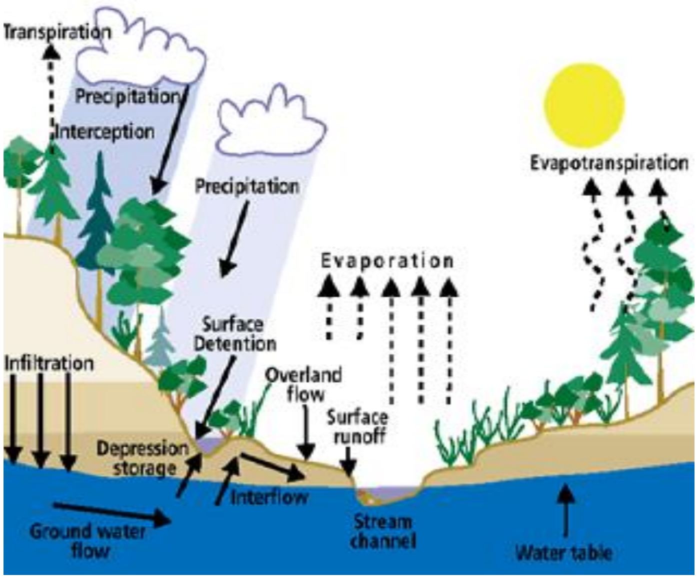

Figure 3. Hydrologic cycle (Allen 2007, used with permission)

The agriculture sector is a significant water user, especially for irrigation. Almost 60 percent of the world's freshwater withdrawals are used for irrigation. In the U.S., 42 percent of freshwater withdrawals from 1960 to 1995 (Figure 4) were for agriculture (USGS 2007). Approximately 70 percent of the water withdrawn (primarily for irrigation) in the U.S. agricultural sector is consumed. The remainder (30 percent) is returned to the water body. In the end, 85 percent of U.S. freshwater consumption is attributable to agricultural activities.

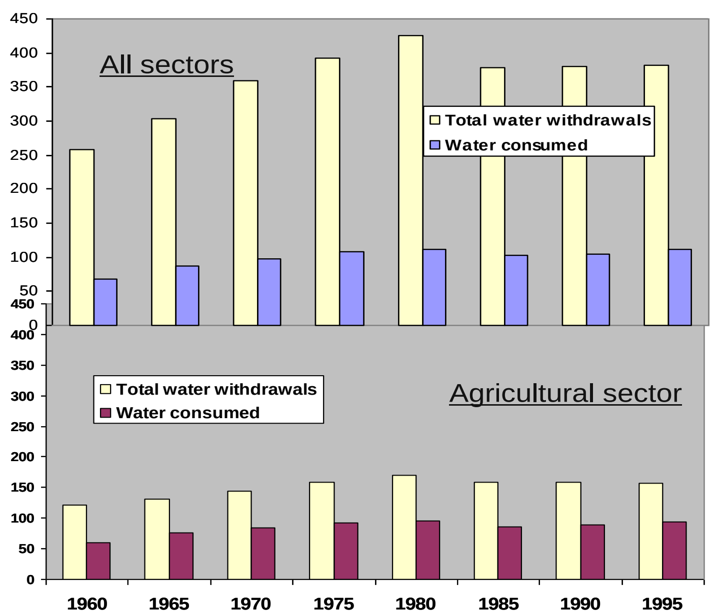

Figure 4. U.S. Freshwater Withdrawals and Consumption, All Sectors and Agricultural Sector, 1960–1995 (million acre-ft/yr, USGS 2007)

U.S. irrigated acreage has increased steadily since 1900, from less than 10 million acres to nearly 60 million acres (USDA 2003). However, the amount of water applied per acre has decreased from 25 inches in the 1970s, to 20 inches today (Gollehon 2007). This decline can be attributed to biotechnology, increased use of water-conserving irrigation practices, improved technical efficiency, higher energy costs, and a shift in irrigation from generally dry areas to more humid regions which require less irrigation water per acre. Surface water is the primary source of irrigation water in the arid western and mountain states. Groundwater is the primary source for the Central states. Four states — California, Idaho, Colorado, and Nebraska — account for half of U.S. irrigation withdrawals.

Historically, biofuels have been produced from grain-based crops with water supplied by precipitation and/or irrigation. Today, agricultural residues, dedicated energy crops, forest wood residues and other herbaceous biomass are being considered as feedstocks for cellulosic ethanol. According to a study led by USDA and DOE, 300 million tonnes of biomass (26 million dry tons of energy crops, 130 million dry tons of forest wood, and 152 million dry tonnes of crop residues) suitable for conversion to ethanol could be available by 2017, and 1.3 billion tonnes could be available by 2050 (Perlack 2005). Although forest wood generally does not require irrigation, the impact of large-scale production of energy crops on water resource availability has not been fully examined.

Water Use in Crude Oil Recovery

In the last 30 years, declining production has made the U.S. increasingly dependent on technologies to recover more from existing domestic wells and imported oil to make up the difference (EIA–AER 2008b). In 2005, the United States produced 5.1 million barrels of crude per day (bbl/d) and imported 10.1 million bbl/d. Of this, Saudi Arabia supplied 1.2 million bbl/d of conventional crude oil and Canada supplied 1.6 million bbl/d of conventional crude oil and bitumen came (EIA 2007b; EIA–AER 2008b).

Saudi Arabia has the world's largest crude oil production capacity, 10.5–11.0 million bbl/d (EIA 2007c). Outside the Middle East, Canadian oil sands are seen as the most readily available oil reserves. Since 2002, the Canadian oil industry has rapidly expanded capacity to produce crude oil from oil sands, nearly doubling production from 0.66 million bbl/d in 2001 to 1.2 million bbl/d in 2007 (CAPP 2008a). It is projected that Canada will produce 2.8 million bbl/d of crude oil from oil sands by 2015 and 3.5 million bbl/d by 2020 (CAPP 2008c).

Water consumption has become an increasingly important factor in conventional and unconventional crude oil production. The petroleum industry has begun to emphasize water management practices and look for alternative water sources to reduce freshwater consumption, particularly in regions where water resources are scarce. Saline water, brackish water, and even desalinated seawater are being used for oil exploration and production (E&P). Large operators are implementing increasingly sophisticated water management practices. Smaller operators, constrained by limited resources, may be less able to do so.

System Boundaries and Water Balance

This analysis defines consumptive or net water use as freshwater input during fuel production activities less output water that is recycled and reused.

Figure 5 depicts system boundaries and water inputs and outputs in feedstock production and fuel processing/production for ethanol and petroleum oil. As shown in Figure 5 (a), the farm receives freshwater from precipitation and irrigation water as needed. Irrigation water that runs off the field to surface streams and recharges groundwater is ultimately returned to the watershed and reused. For this analysis, we assume a system that includes the farm and its watershed; surface water run-off and groundwater recharge are within this system.[3] Note that this assumption is appropriate because we focus on regional feedstock production, not individual farm operations. In this context, the consumptive use of corn irrigation water accounts for water loss from soil percolation, ET, and absorption to the crop (Figure 5 (a)).

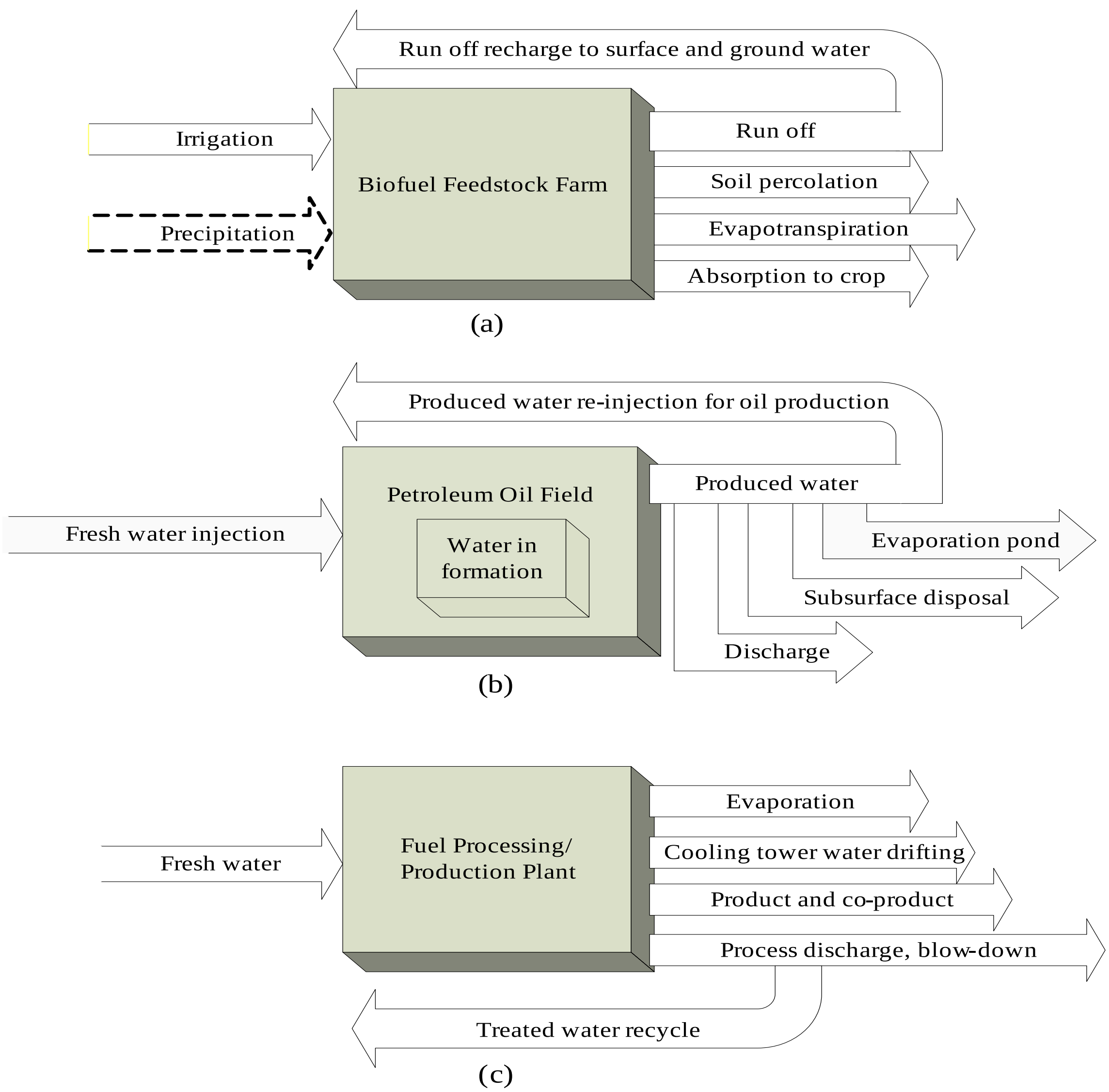

Figure 5. Water Inputs and Outputs for (a) Biofuel Feedstock Production; (b) Petroleum Oil Production; and (c) Ethanol Production/Oil Refining

[3] Since precipitation is not within the system, it is shown as a dashed input.

In an oilfield, freshwater and a portion of produced water are introduced through an injection well. Produced water lifted from the production well includes previously injected water as well as saline water originally contained in the formation. Some of the produced water is disposed to the subsurface through disposal wells. For an individual oil field, local geology and hydrology strongly affect the system boundary — defining a closed system if injection water is retained in the formation or an open one if injection water flows to nearby formations. For this analysis, we assume a closed system — injection water is retained in the formation into which it is injected — and that disposal wells to which some produced water is pumped are outside the system boundary. Given this assumption, produced water re-injection is conceptually equivalent to water recycle, and consumptive use of fresh injection water for oil production accounts for water loss by produced water disposal (to the subsurface, an evaporation pond or discharge). Figure 5 (b) illustrates this equivalence.

As shown in Figure 5 (c), consumptive water use in the fuel production process includes water loss through evaporation, drifting,[4] and blow-down from the cooling tower, incorporation into products and co-products, and process water discharge.

Consumptive Water Use in the Corn Ethanol Lifecycle

Based on average consumption of 3.0 gal of water/gal of corn ethanol produced in a dry mill plant, average irrigation water use for corn farming in USDA Regions 5, 6 and 7, and dry mill ethanol yields of 2.7 gal per bushel, we estimate total consumptive water use for corn ethanol production for each region (Table 1). Since total groundwater and surface water use for corn growing vary significantly by region, producing one gal of corn-based ethanol consumes a net of 10 to 17 gal of freshwater when the corn is grown in Regions 5 and 6, as compared with 324 gal when the corn is grown in Region 7.

Table 1. Consumptive Groundwater and Surface Water Use from Corn Farming to Ethanol Production in Regions 5, 6, and 7 (gal water/gal denatured ethanol produced)

USDA Regions	**Region 5**	**Region 6**	**Region 7**
Share of U.S. ethanol production capacity (%)[a]	*51*	*17*	*27*
Share of U.S. corn production (%)[b]	*53*	*17*	*19*
Corn irrigation, groundwater[c]	6.7	10.7	281.2
Corn irrigation, surface water[c]	0.4	3.2	39.4
Ethanol production[d]	3.0	3.0	3.0
Total (corn irrigation and ethanol production)	10.0	16.8	323.6

[a] Based on 2006 ethanol production capacity in operation (RFA 2007).
[b] Based on 2006 corn production (USDA-NASS 2007).
[c] Source: USDA (2003).
[d] Source: Wu (2008). Production-weighted average.

[4] As downward flowing cooling water contacts upward rising ambient air in the cooling tower, a small amount of water is lost. This loss is commonly referred to as “drifting” or “windage”.

<u>Consumptive Water Use in the Cellulosic Ethanol Lifecycle</u>

Cellulosic ethanol can be produced from a variety of sources including dedicated energy crops like perennial grasses, forest wood residues, short-rotation woody crops and agricultural residues like corn stover, wheat straw, rice hulls, cotton gin, etc. For this analysis, switchgrass is chosen as an example. Switchgrass is assumed to be grown in its native region and transported to local biorefineries for conversion to ethanol via biochemical or thermochemical processes.

a. Feedstock Irrigation

Irrigation requirements depend on the type and origin of the feedstock, the climate in which it is grown and soil conditions. Switchgrass and other perennial grasses are deep-rooted and efficient in their use of nutrients and water, and thus tend to be relatively drought tolerant. In its native habitat, switchgrass yields of 4.5 to 8 dry tons per acre (Downing 1995; Ocumpaugh 2002; Taliaferro 2002) are possible without irrigation. Although irrigation could increase yield, it may not be sufficient to offset additional costs for water, pumps and energy. If switchgrass were grown in regions where it is not native (e.g., certain parts of the northwestern U.S.) irrigation would be needed (Fransen and Collins 2008). In this study, we assume switchgrass is grown in its native habitat to yield 4–7 dry tons per acre, and irrigation is not required.

b. Cellulosic Ethanol Production

Ethanol can be produced from switchgrass via several processes:

- Biochemical conversion (BC) using enzymatic hydrolysis and fermentation,
- Thermochemical conversion (TC) using gasification and catalytic synthesis,
- Thermochemical conversion using pyrolysis and catalytic synthesis, or
- A hybrid approach combining gasification followed by syngas fermentation.

The amount of water consumed during ethanol production depends on the process and the degree of water reuse and recycling. Gasification consumes relatively little water. The BC process requires water for additional pretreatment steps to break down the cellulosic feedstocks. With current technology, producing one gal of cellulosic ethanol via a BC process (such as dilute acid pretreatment followed by enzymatic hydrolysis) consumes 9.8 gal of water (Wallace 2007). With increased ethanol yield, it is estimated that consumptive water use can be reduced to 5.9 gal (Aden 2002). By comparison, an optimized TC gasification process requires only 1.9 gal of water to produce a gal of fuel ethanol (Phillips 2007).

Numerous efforts are underway to reduce water intensity. For example, advanced process simulation tools are being used to identify opportunities to minimize energy and water consumption through improved process integration. NREL is attempting to optimize the BC process to increase water recycling and reuse. And, private-sector developers are pursuing novel processes, including syngas-to-ethanol using a hybrid approach which combines gasification with syngas fermentation to produce ethanol. The freshwater requirement for this latter process is claimed to be less than one gal for each gal of ethanol produced (Coskata 2008).

If no irrigation water is used for feedstock production, switchgrass-based cellulosic ethanol consumes only the water needed for conversion via BC, TC or hybrid processes. Based on the above-noted sources, production of a gal of cellulosic ethanol could consume 1.9–9.8 gal of water.

From a lifecycle perspective, switchgrass consumes a minimal amount of water relative to most sources of corn ethanol. As compared to Table 1, cellulosic ethanol produced from switchgrass via a BC process consumes nearly as much water (9.8 gal) as ethanol produced from corn grown in Region 5 (10.0 gal). However, cellulosic ethanol produced from switchgrass via a thermochemical process requires 80 percent less water.

Consumptive Water Use in the Petroleum Gasoline Lifecycle: U.S. Onshore Wells

Because of wide variations in the geology and characteristics of individual wells, there is no "typical" domestic recovery regime. Wells may be relatively new or nearing the end of their productive lives; field geologies may be complex or relatively simple; water resources may be plentiful or scarce. Rather than characterizing a range of wells, this analysis sought to construct a series of composite estimates of water intensity for the regions accounting for the bulk of domestic onshore production. As noted above, the focus is on PADD regions II, III and V which together represent 90 percent of U.S. domestic onshore crude oil production and 81 percent of U.S. refinery output (EIA 2007d).

For crude oil recovery, consumptive water use is largely injection water that cannot be recycled and reused (Figure 5b). Since recovery can be accomplished via several technologies each of which have different water requirements, technology-specific water intensities (i.e., water injection requirements) are estimated and coupled with market shares to calculate technology-weighted injection water requirements (gal/gal). Then, the amount of produced water (PW) re-injected into the formation is estimated and subtracted from the total.

To estimate PW, injection water is first calculated as a technology-weighted average, then coupled with the ratio of PW to oil recovery (PWTO) which is calculated for each region. The product of produced water (PW) and the share of PW that is re-injected for oil recovery is then subtracted from this total. The remainder is net water use for crude oil recovery.

Onshore wells currently account for 67 percent of domestic oil production, the bulk of that via secondary recovery. Although the consensus is that most offshore wells use primary recovery, no technology-specific data are publicly available on offshore recovery technologies. For this analysis we assume all offshore production is via primary recovery.

As shown in Figure 6 water flooding is responsible for three-quarters of onshore production. While thermal steam EOR is the most widely used tertiary recovery technology, CO_2 injection (miscible) has been growing rapidly and is now the second most commonly used EOR technology. Other EOR technologies include nitrogen gas injection, forward air combustion, hydrocarbon miscible/immiscible, and a small amount of hot-water injection. Each of these technologies represents about 2 percent of total EOR (O&GJ 2006).

Injection water requirements vary with recovery technology. Primary recovery requires an average of only 0.21gal of freshwater/gal of crude oil recovered (Gleick 1994). As a general rule, secondary recovery is relatively water intensive, but injection water requirements vary with the age and characteristics of the individual well, the formation in which it is located and the region.

Based on their analysis of the history of 80 U.S. secondary recovery projects, Bush and Helander (1968) show that over their water-flooding lifetime, an average of 8.6 gal of water is injected to recover a gal of crude. Water flooding can increase overall water requirements further if injection water is supplemented by freshwater not otherwise used for oil recovery.

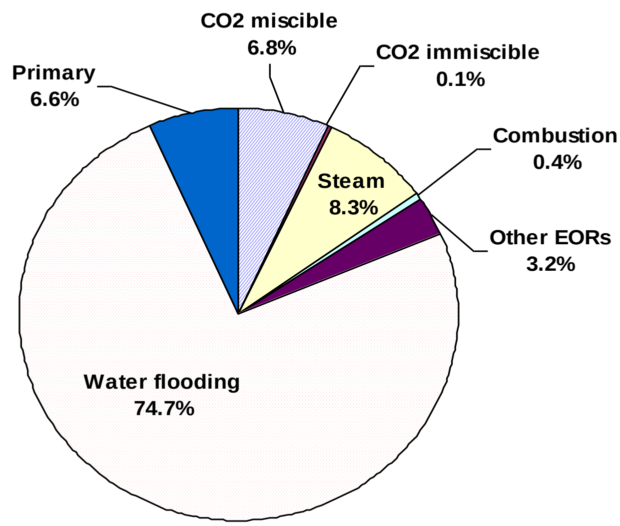

Figure 6. Onshore U.S. Crude Oil Recovery by Technology (EIA 2007b; O&GJ 2006)

Injection water use for EOR (or tertiary oil recovery) can be as low as 1.9 gal per gal of oil recovered with forward combustion or as high as 343 gal/gal of oil with more water-intensive techniques like micellar polymer injection. With CO_2 injection, reports of water use are extremely variable. Based on a survey of 14 oil companies conducted in the early 1980s, Royce (1984) reported water use of 13 gal of injection water per gal of crude oil recovered; Gleick (1994) reported 24.7 gal/gal recovered in the early 1990s; and1988 to 1998 data from Shell's CO_2 EOR Denver City project show that injection water averaged only 4.3 gal/gal (Barry 2007). Moreover, Royce suggested that zero freshwater injection can be achieved for CO_2 EOR because injection water quality is not important with this technology. For this analysis, we assume 13 gal per gal recovered with CO_2 EOR. For those EOR technologies for which water use is not reported in the open literature (such as hydrocarbon miscible/immiscible, hot water and N_2 technologies), we assume 8.7 gal/gal, the average injection water use for CO_2, steam and combustion EOR schemes.

In 2005, domestic onshore recovery operations required 1,171 million gal of injection water to produce 146 million gal of conventional crude oil (Table 2). Technology-weighted average water injection was 8.0 gal of water/gal of crude. This estimate does not include treated PW injected for oil recovery. Secondary water flooding is responsible for 79.7 percent of injection water use in U.S. onshore oil production. Although micellar-polymer-based recovery currently consumes relatively large amounts of water, there are no active projects employing this technology in the United States (O&GJ 2006). The same is true for caustic/alkaline, surfactant, and other polymer-based oil recovery methods (O&GJ 2006). Hence, these technologies are not included in this analysis. Regardless of the technology, there are significant variations in injection water required for oil recovery from region to region. For example, Texas Oil and Gas District 8 and 8A at West Texas injected 12.7–14.7 gal of water to recover a gal of crude oil in 2005 (Texas Railroad Commission 2008), which is 60–80% higher than the estimated national average.

Assuming a national average PWTO ratio of 9.5 gal of PW per gal of crude and that 71 percent of PW is re-injected for oil recovery, national net water consumption is estimated to be 1.3 gal/gal of crude from U.S. onshore wells.

Table 2. Water Injection in U.S. Onshore Oil Production by Recovery Technology

	Oil Production		Water Injection		
Recovery Technology	**(bbl/d)[a]**	**(mln gal/d)**	**(gal/gal crude)**	**(mln gal/d)**	**Technology Share (%)**
CO_2 miscible	234,315	9.8	13.0	127.9	10.9
CO_2 immiscible	2,698	0.1	13.0	1.5	0.1
Steam	286,668	12.0	5.4	65.0	5.5
Combustion	13,260	0.6	1.9	1.1	0.1
Other EOR[b]	112,276	4.7	8.7	40.9	3.5
Secondary water flooding	2,589,000	108.7	8.6	933	79.7
Primary recovery	227,783	9.6	0.2	2.0	0.2
Total	3,466,000	145.6		1171	100
Technology-weighted average water injection (excludes produced water re-injection)			**8.0**		

[a] Production data for EOR technologies from O&GJ (2006).
[b] Data on water use are not publicly available for "other EOR" technologies including hydrocarbon miscible/immiscible, hot-water flooding, and nitrogen injection. Average values of CO_2, steam and air combustion assumed for other EOR.

PWTO varies considerably from one well or region to another, and within an individual well as it ages. According to the Texas Railroad Commission (2008), PWTO is about 1.0–1.2 gal of PW per gal of crude in the Texas Oil and Gas Districts 8 and 8a, as compared to the average ratio in PADDIII, 10.9. This low ratio reflects local hydrology. This low PW yield cannot meet the injection water demand of 12.7–14.7 gal per gal of oil in these two districts. Thus, fresh water, as well as large amounts of saline/brackish water from underground aquifers, is used for oil recovery.

Indeed, for individual wells that employ water management practices diligently and use less water-demanding recovery technologies, it is conceivable that 100 percent of PW can be re-injected for oil recovery and net water consumption could approach zero. The constraint to increased PW recycling and reuse is the associated cost for lifting and water treatment as compared with employing other competing technologies. The choice will depend on local and regional conditions.

<u>Consumptive Water Use in the Petroleum Gasoline Lifecycle: Saudi Wells</u>

Saudi Arabia is the largest oil producer in the world and its Ghawar field is the world's largest oil field. Most Saudi wells are relatively young and do not require large quantities of injection water to maintain pressure. Nevertheless, scarce rainfall and a lack of surface water make water supply a serious problem. Oil production consumes Saudi Arabia's most valuable water resource which is groundwater contained in seven major aquifers and for which recharge rates are low.

Faced with accelerated groundwater depletion caused by industrial and urban development, Saudi Arabia has launched a major effort to develop new water supply sources and water conservation projects. Much of this effort has been focused on oil recovery. Beginning in the late 1970s, Saudi Arabia's petroleum industry began replacing subsurface saline water flooding with desalinated seawater injection. Although a complete survey of net water use for Saudi crude oil production is not publicly available, results of individual projects provide an indicator of current practices and recent trends. For example, results of a six-year water management program at North 'Ain Dar, indicate that water injection dropped from 6 gal/gal of oil recovered to 4.6 gal/gal (a 30 percent reduction). During the six-year period from 1999 to 2004, oil and water production, water injection and reservoir pressure remained constant (Alhuthali 2005). Saudi Arabia currently relies almost entirely on brackish water and desalinated seawater for oil recovery.

In the Ghawar field, which accounts for more than half of Saudi Arabia's crude oil production (EIA 2007c), roughly 7 million bbl/d of treated seawater are injected to produce 5 million bbl/d of crude (or 1.4 gal water/gal oil) (Durham 2005). Today, the PWTO ratio is about 0.39 (SUSRIS 2004) for all Saudi operations, as compared with an average of 9.5 for U.S. onshore production. It is reported that this ratio has declined steadily for Ghawar, from 0.54 to 0.43, because of a shift in recovery technology to horizontal drilling and peripheral water injection (SUSRIS 2004; Durham 2005). Although data on reuse and recycling of produced water are not available, as a general rule little produced water from Saudi oil production is available for re-injection.

<u>Consumptive Water Use in the Petroleum Gasoline Lifecycle: Canadian Oil Sands</u>

Of Canada's 179 billion bbl of proven reserves, 175 are contained in oil sands (O&GJ 2006). Production of oil sands-derived crude oil grew from 0.66 million bbl/d (CAPP 2008b) in 2001 to 1.1 million bbl/d (43 percent of Canadian crude oil production) in 2006. This growth has been spurred by increased demand for transportation fuels, particularly in the U.S., as well as technological improvements that have reduced production costs, fiscal policies that have provided incentives for oil sands investment, and record world oil prices. In the past decade, production has routinely exceeded forecasts, prompting repeated upward revisions. However, a number of critics caution that annual output may be limited by water resources. Unless techniques are developed to reduce water use, they contend that there is only enough water available to support production of 2–3 million bbl/d of oil-sands-based crude oil (Peachey 2005), a level that may be reached by 2012–2016 (CAPP 2008c). Further, some argue that because of the rapid pace of new project development, current technologies are being used in preference to advanced technologies that might take longer to implement but have the potential to reduce water intensity over their lifetime (Griffiths 2006).

Oil sands are composed of sand, silt and clay, water, and about 10–12 percent crude bitumen, a thick, tar-like substance containing high levels of sulfur and nitrogen compounds (Alberta Energy 2004). As compared with petroleum, producing gasoline from oil sands typically requires an additional processing step following extraction. In this step, oil sands are upgraded into synthetic crude oil which is then refined into products like gasoline and diesel oil. Upgrading may occur in integrated, onsite operations as part of surface mining, or offsite, if pipelines are available to transport the bitumen and a diluent is added to improve its viscosity.

a. Oil Sands Recovery

Oil sands are typically recovered by open-pit or surface mining of relatively shallow deposits, or by thermal in situ techniques for deeper deposits. Surface mining accounted for 59 percent of Canadian oil sands-based crude oil production in 2006 (up from 56 percent in 2005) while in situ extraction accounted for 41 percent. In situ operations are expected to dominate future oil sands recovery operations.

Surface Mining

In the early years of oil sands development, surface mining was the dominant recovery technology since the largest and most heavily developed deposit, near Fort McMurray in Northern Alberta (commonly called the Athabasca deposit), includes all of Canada’s surface-minable reserves as well as extensive reserves that can only be recovered by in situ techniques. As the deeper Peace River and Cold Lake deposits (as well as non-minable portions of the Athabasca deposit) have been developed, in situ extraction has grown to account for a larger share of oil sands-derived crude oil.

Approximately 18 percent of Canada’s remaining oil sands reserves are amenable to surface mining (CAPP 2008c). Land disruption is extensive — from site clearing, to the mining process itself and the long-term storage and containment of tailings, a paste-like substance remaining after long-term settling in a tailing pond.

There are two major options for reducing water use in extraction and upgrading from surface mining. If naphtha (produced from upgrading) is used for froth treatment, over 98 percent of the bitumen can be recovered, but residual water and solids pass into the bitumen stream creating downstream problems in upgrading operations, and increasing water use and intensity. If a paraffinic solvent is used for froth treatment, residual water and solids can be reduced, thereby averting these problems, but hydrocarbon yield tends to decline (Flint 2005).

In Situ Recovery

Approximately 82 percent of Canada’s oil sands reserves are only recoverable via processes that extract the bitumen without removing the rock matrix from its bed (CAPP 2008c). These in situ processes typically involve drilling into the reservoir, heating it with steam so the bitumen separates from the sand and clay, pumping it to the surface, and (if necessary) mixing it with a diluent so that it is fluid enough to flow through a pipeline. The two dominant in situ technologies are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). Both require large volumes of steam, which in turn requires water and energy.

The choice of in situ technology depends on the geology of the formation — CSS tends to work best in deep, thicker reserves with good horizontal permeability (like those near Cold Lake and Peace River) while SAGD works better in deposits with thinner reserves and good vertical permeability (like the Athabasca deposit near Fort McMurray). SAGD tends to require lower injection pressures and results in lower steam/oil ratios, making it somewhat less water intensive and less costly than CSS. However, these reductions may be as much a function of the geology and hydrology of the formation as the characteristics of the technology.

As compared with surface mining, which can recover 90 percent of the bitumen in the ore (NEB 2004), in situ methods have somewhat lower recovery rates. SAGD reportedly can recover 60–80 percent of the bitumen in the reservoir (Woynillowicz 2005), while CSS can recover approximately 20-35 percent with typical steam/oil ratios of 3 to 4 (Flint 2005).

Technology Shares

Isaacs (2007) estimates that 16.3 percent of in situ production is via SAGD (Athabasca), 19.0 percent via CCS (Cold Lake), and 1 percent via multi-scheme techniques (Peace River), and that synthetic crude oil recovered via in situ processes accounts for 36.3 percent of Canadian crude oil production. By contrast, CAPP (2008b) data indicate that in situ recovery accounted for 44.4 percent of production in 2005. Using CAPP's share for in situ recovery and Isaacs' shares for recovery technologies, we estimate technology shares for in situ production in 2005 (Table 3).

As with conventional oil, oil sands recovery technology has a major effect on water consumption. Surface mining and multi-scheme techniques[5] are considerably more water intensive than SAGD or CSS with current levels of water recycle and reuse. Surface mining — which is utilized primarily at the Athabasca project — is particularly problematic since the water used in the extraction plant is withdrawn from the Athabasca River where public concerns regarding resource use, emissions and waste generation have prompted extensive efforts to conserve and better manage water resources. According to Gleick, the oil sands industry used an average of 4.8 gal of freshwater to produce a gal of oil (before upgrading) in1994 when operations were concentrated in Fort McMurray and recovery was via surface mining. By 2005, that average had dropped to 4 gal/gal including upgrading and water recycle and reuse (Peachey 2005). More recently, Heidrick and Godin (2006) as well as Isaacs (2007) report that water intensity in Alberta is 2.18 gal/gal including upgrading. For our estimate, we use Peachey's industry average (4.0 gal/gal).

Table 3. Net Water Use for Oil Sands-Based Synthetic Crude Oil Production by Location, Recovery Method and Technology[a]

Location and Recovery Method	**Bitumen Recovery Technology**	**Share of Oil Sands Crude Production** (%)	**Net water use[d]** (gal/gal oil sands)	
			Recovery	Upgrading
Athabasca – Mining	Shovel and truck	55.6[b]	4.0[a]	–
Athabasca – In Situ	SAGD[e]	22.0[c]	0.3	1.0
Cold Lake – In Situ	CSS[e]	21.2[c]	1.2	1.0
Peace River – In Situ	Multi-scheme	1.2[c]	4.0	1.0

[a] Including water recycle and bitumen upgrade.
[b] CAPP 2008b.
[c] Isaacs 2007.
[d] Surface mining net water use: Isaacs 2007; Peachey 2005; Heidrick and Godin 2006. SAGD, CSS and multi-scheme net water use: Gatens 2007.
[e] SAGD = steam-assisted gravity drainage; CSS = cyclic steam stimulation.

[5] Multi-scheme technologies include various elements of CSS, SAGD and other recovery techniques.

Table 3 also provides water intensity (net water use) by recovery technology. Although both SAGD and CSS are steam intensive, their net water use is relatively low since over 80 percent of the steam used for oil extraction and processing is recycled (Isaacs 2007). Despite water conservation efforts, the use of cold-water flooding is on the rise at several oil sands surface mining projects. Cold water flooding is comparable to conventional water flooding in secondary oil recovery. This technique reduces the high energy cost associated with oil sands mining, but might increase freshwater consumption unless alternative sources such as saline water are used (Griffiths 2006).

b. Oil Sands Upgrading

Today, most surface-mined oil sands are upgraded to synthetic or "refining-ready" crude oil in Northern Alberta, as part of integrated operations that also separate bitumen from the feedstock ore. Since the thick crude oil is deficient in hydrogen, upgrading requires hydrogenation (typically by reforming natural gas, or gasifying coal, coke or asphaltene) or coking to convert it to an acceptable refining feedstock.

Although net water use has dropped dramatically in the past few years, strains on local water resources (primarily the Athabasca River) suggest that onsite upgrading capacity may not be expanded as recovery operations grow in the Fort McMurray area (Griffiths and Dyer 2008). Upgrading is already migrating toward Edmonton. In 2003, Shell added an upgrader to its refinery at Scotford, northeast of Edmonton. Eight other upgraders (including an expansion to Scotford) with a combined capacity to upgrade almost two million b/d into synthetic crude oil are now in various stages of planning or construction. Known as "Upgrader Alley", this area may contain over 40 percent of Alberta's upgrading capacity within the next decade (Griffiths and Dyer 2008).

Unlike surface-mined oil sands upgraded to synthetic crude oil, bitumen recovered via in situ processes historically has been transported by pipeline to refineries, mostly in the U.S. (CAPP 2008c). Upgrading uses less than 1 gal of water/gal of crude (Peachey 2005).

Refining

In a typical North American oil refinery, most water is used for steam production, cooling and process needs. According to CH_2MHill (2003), approximately half of refinery water requirements is from the cooling tower. Evaporation, blow down and drift are the principal routes of water loss in cooling and boiling operations, which together account for 96 percent of refinery water consumption (Figure 7).

Based on estimates from 1994 to 2006 (Gleick 1994; Ellis 1998; Buchan and Arena 2006), processing a gal of crude oil in U.S. refineries consumes 0.5–2.5 gal of water, or an average of 1.5 gal of water for each gal of crude. Because of yield gain during crude processing (i.e., 42 gal of crude generate 44.6 gal of refined product), consumptive water use can also be expressed as 1.4 gal of water per gal of refined product.

The synthetic crude oil produced from oil sands upgrading passes through the refining process in much the same way as conventional crude oil and has comparable water requirements. In this study, we assume refining water use to be 1.5 gal of water per gal of synthetic crude oil (after upgrading).

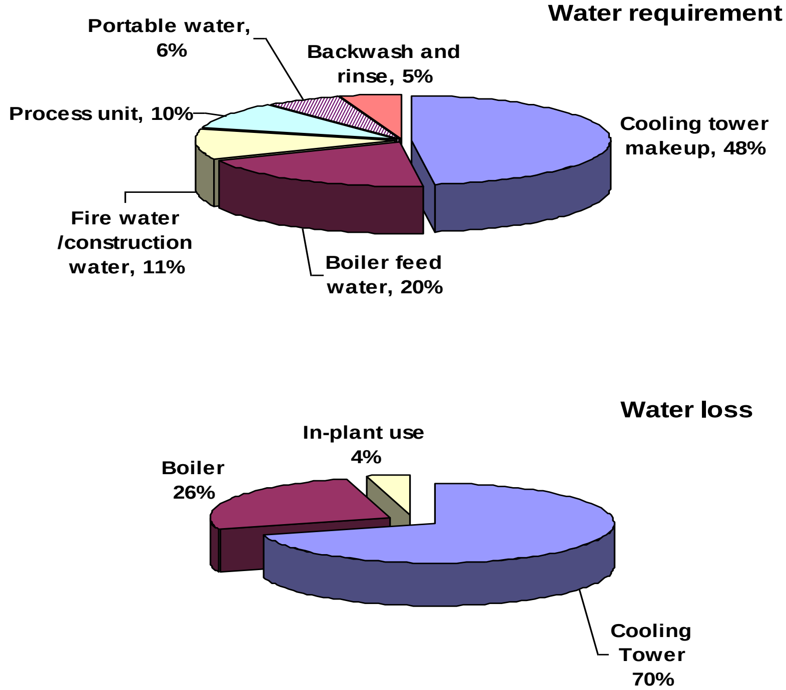

Figure 7. Water Requirements and Losses in a Typical Refinery (CH_2MHill 2003)

<u>Results</u>

a. Corn Ethanol

Crop irrigation is the single most important factor affecting water use in the production of corn ethanol. Because of different climate zones and soil types, there are significant differences in irrigation among the three major corn-producing regions. Approximately 68 percent of U.S. corn and 66 percent of U.S. corn ethanol are produced in Regions 5 and 6, where 10–17 gal of irrigation water are consumed per gal of ethanol produced. Corn irrigation is much higher in Region 7.

Ethanol production plants are relatively less water intensive compared to the water requirement for crop irrigation. The combination of newly-built production facilities with better process integration and, to a lesser extent, production of wet distillers grain (WDG) co-products in dry mill plants (as compared with dried distillers grain and solubles, DDGS)[6] have reduced water use dramatically. Average consumptive water use in ethanol plants has declined from 6.8 gal/gal ethanol to 3.0 gal/gal ethanol in the past ten years.

[6] WDG requires less steam for drying, thereby reducing water use. The major advantage of WDG, however, is in energy savings.

b. Cellulosic Ethanol

Water requirements for cellulosic ethanol production are uncertain since the technologies are not yet commercialized and estimates are often based on model results. Nevertheless, they are likely to vary with technology. The current biochemical conversion (BC) process requires nearly 10 gal of water to produce a gal of ethanol. Increased ethanol yield may reduce this requirement to 6 gal of water. Thermochemical conversion (TC) via gasification followed by catalytic synthesis requires much less water — less than 2 gal/gal for an optimized gasification to mixed alcohol process.

c. Gasoline from U.S. Crude Oil

Water consumption in oil exploration and production (E&P) is highly sensitive to the age of the well, the recovery technology employed, and the degree of produced water recycling and reuse. Primary oil recovery requires only 0.2 gal of water per gal of crude oil produced. With the exception of offshore wells, U.S. oil production relies heavily on secondary recovery via water flooding. This technology requires an average of over 8 gal of water per gal of crude oil recovered and, as a result, accounts for 80 percent of the water injected into onshore wells for oil recovery. However, since produced water supplies much of this injection water, on a technology-weighted basis, average net water use for U.S. crude oil production ranges from 2 to 5.5 gal per gal of crude oil for the three major oil production regions (with significant variations from field to field). Produced water is especially low in parts of West Texas, necessitating significant use of saline groundwater for injection.

Although enhanced oil recovery (EOR), via technologies like steam injection and CO_2 flooding, is less prevalent than water flooding, it accounts for an increasing share of onshore production. As of 2005, water inputs for steam injection and CO_2 flooding represented nearly 6 percent and 11 percent, respectively, of total water injection in domestic onshore wells.

In contrast to E&P, oil refining consumes relatively small amounts of water, from 0.5 to 2.5 gals per gal of crude oil processed. Combining oil E&P and refining, producing a gal of gasoline from conventional crude in Saudi Arabia or in the U.S. can consume as little as 2.8 or as much as 6.6 gals of water.

d. Gasoline from Saudi Crude Oil

For this study, we use a range of net water use assumptions, from 1.4 gal (Durham 2005) to 4.6 gal per gal of crude recovered, the average for North ‘Ain Dar (Alhuthali 2005).

e. Gasoline from Canadian Oil Sands

The amount of water consumed in producing crude oil from Canadian oil sands varies with production technology, which in turn depends on geologic conditions. Surface or open pit mining and upgrading require five gals of freshwater (primarily surface water from the Athabasca River) to produce a gal of synthetic crude oil. The two dominant in-situ technologies, steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS), require large quantities of steam for bitumen recovery. Utilizing extensive recycling to lower water use, recovery operations require 1.3–5.0 gal of water to produce a gal of bitumen. From E&P to refining, a total of 2.6–6.2 gal of water is needed to produce a gal of gasoline from oil sands.

Issues

Each fuel lifecycle presents unique opportunities and challenges for consumptive water use. There are, however, a number of common issues. Consumptive water use by all lifecycles raises issues of sustainability; has the potential to affect water quality and land degradation; and involves some measure of ecosystem disruption. For the most part, these issues apply primarily to feedstock production. For example, aquifer depletion may be exacerbated as a result of irrigation water demands for corn growing or injection water needs for conventional or oil sands-based crude oil recovery. Fuel processing tends to be less water-intensive, due to a combination of integrated operations and more extensive water recycling and reuse.

Cumulative impacts are a particularly critical issue with respect to oil sands development. The notion of individual impacts accumulating over time and across numerous nearby projects, in contrast to the per-gallon water use results as examined in this study, is particularly applicable to questions of sustainability, and none more so than with respect to water resources.

Conclusions

This analysis found that consumptive water use for feedstock and fuel production varies considerably by region, type of feedstock, soil and climatic condition, and production technology for bioethanol; and by age of oil well, recovery technology, and extent of produced water re-injection and steam recycling for petroleum gasoline (see Table 4). There are significant regional differences, however, particularly for corn production.

Table 4. Consumptive Freshwater Use for Ethanol and Petroleum Gasoline Production

Fuel (feedstock)	Net water consumed[a]	Major factors affecting water use
Corn ethanol	10–324 gal/gal ethanol[d]	Regional variation caused by irrigation requirements due to climate and soil types
Switchgrass ethanol	1.9 –9.8 gal/gal ethanol[d]	Production technology
Gasoline (U.S. conventional crude)[b]	3.4–6.6 gal/gal gasoline	Age of oil well, production technology, and degree of produced water recycle
Gasoline (Saudi conventional crude)	2.8–5.8 gal/gal gasoline	Same as above
Gasoline (Canadian oil sands)[c]	2.6–6.2 gal/gal gasoline	Geologic formation, production technology

[a] In gal of water per gal of fuel specified.
[b] PADD II, III and V combined.
[c] Including thermal recovery, upgrading and refining.
[d] All water used in ethanol conversion is allocated to the ethanol product.

In response to growing demand for oil products, refining capacity is expanding globally, including in regions with scarce resources. By 2025, 40 percent of global refining capacity may be in water-scarce regions (Buchan and Arena 2006). As with crude oil recovery, refineries are initiating water management projects in response to limited freshwater supplies. Individual refineries are reducing consumption by identifying alternative water sources, increasing steam condensate recovery, and maximizing water and wastewater recycling and reuse. Today, approximately 70 percent of steam condensate is recovered in well-maintained and newer refineries around the world, as compared with only 30 percent recovery in older refineries

(Seneviratne 2007). Wastewater recycling and reuse is also becoming increasingly common. Reclaimed water from municipal wastewater treatment plants to supply refinery water needs shows substantial cost benefits (Buchan and Arena 2006). Cogeneration, which uses less water for on-site power generation than the same power generated by coal-fired boilers or steam-condensing turbines, is yet another area of potential water savings.

Water consumption can be reduced by increasing the use of steam condensate reuse and treated process water recycling, and by implementing process modifications using existing commercial technologies. For cellulosic ethanol facilities, a process optimized for water use should be encouraged. Finally, the use of produced water re-injection for oil recovery should be increased.

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