CHAPTER 10: Gasoline and Petroleum Diesel

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10.1 Background

Multiple analyses have been performed to evaluate life cycle environmental footprints of petroleum derived fuels. Public domain data are available through analyses performed by the National Energy Technology Laboratory (NETL; Skone and Gerdes, 2008), analyses available from Argonne National Laboratory (ANL, 2009), analyses performed by the US EPA as part of the development of the renewable fuel standard (EPA, 2009a,b), and others.

While the ANL and NETL analyses are the most widely used and comprehensive life cycle assessments of petroleum fuels done to date, data on water use is limited, particularly for exploration and production activities. Therefore, in this work, the focus was on augmenting existing life cycle analyses of petroleum based fuels with data on water withdrawals and consumption, particularly in exploration and production activities.

10.2 Water Use in Acquisition of Oil and Gas

Water use for petroleum production from the well and before transport to the refinery was investigated by ERG/Franklin Associates, a subcontractor on the project and the primary source of data for the US Life Cycle Inventory (NREL, 2009). For this analysis, water use includes both consumption and withdrawals. In the first case, water is lost to evaporation while in the second case, the water is returned to the formation in some form. As documented later in this Chapter, sometimes the distinction between consumption and withdrawal is not as entirely clear. Issues of distinguishing between consumption and withdrawal will be discussed as they arise.

Although the primary life cycles addressed for this project are for petroleum gasoline and diesel, both of which are derived from crude oil, natural gas was investigated as well. This is for two reasons: (1) oil and gas are often extracted simultaneously and (2) natural gas is used as a material and/or energy source in many of fuel life cycle stages for both conventional and non-conventional fuel production.

Oil and gas activities use major quantities of water at different stages:

- Drilling
- Fracturing (where water is pumped into the rock layer until it fractures)
- Secondary recovery (waterflood)
- Tertiary recovery (steam injection)

For drilling and fracturing operations, water is brought into the work area from somewhere else. Once a well goes into production, however, water comes up the well bore along with the petroleum. Thus, the production phase might include both water generation and water disposal/reuse. In primary recovery, oil, gas, and/or water flow into the well under the natural pressure of the reservoir. In secondary recovery, oil recovery is assisted by mechanical means without changing the physical characteristics of the reservoir. Two main secondary approaches are “lifting” and “flooding.” The familiar image of the up and down motion in a walking beam pump lowers the pressure in the borehole below that in the reservoir to lift the oil to the surface.

In flooding, either gas (gas injection) or water (water flood) is pumped into the reservoir through an injection well to maintain reservoir pressure and push the petroleum to the well bore. At some point in time, the injected fluid will traverse the reservoir ("break through") and begin coming up the well bore in substantial quantities. Depending on the amount of oil remaining in the reservoir, a company might decide to move to tertiary recovery where the flow characteristics of the oil are changed, in addition to maintaining reservoir pressure. This might mean thermal treatment (steam flooding or in-situ combustion), CO_2 injection (where the gas mixes with the hydrocarbons, i.e., "miscible displacement"), or chemical injection. Tertiary recovery is also called "enhanced oil recovery" or EOR (EIA, 2009a and Schlumberger, 2009).

10.2.1 Projected Oil and Gas Production in the United States

The Energy Information Administration (EIA) provides projections of oil and gas production from 2006 to 2030 (EIA, 2009b). From 2010 to 2030, oil production increases from 5.61 million barrels per day to 7.38 million barrels per day. The relative percentage of oil produced from offshore sources increases slightly from 36 percent in 2010 to 38 percent in 2030:

Table 10.1 presents the projected gas production for the period 2010 to 2030. As Table 10.1 implies, forecasting gas production is more complicated than projecting oil production due to the different sources for the gas. The top three lines show the projections for associated gas (that is, gas that comes up the borehole with the oil) from onshore, offshore, and Alaska. At this time, most life cycle analyses attribute all water use to oil operations (e.g., see ANL, 2009) on a "barrel-of-water to barrel-of-oil" ratio. A more accurate metric might incorporate the energy value of the "associated gas-in-water to oil" ratio by putting the ratio on a barrel-of-oil-equivalent (BOE) basis.

Non-associated gas comes up what is typically called a "gas well." Table 10.2 indicates that the onshore production of conventional gas is projected to drop from 23 percent of total gas production in 2010 to 9 percent of total gas production in 2030. Offshore production of conventional gas is projected to increase from 13 percent of total gas production in 2010 to 16 percent of total gas production in 2030.

Conventional gas collects in a geological trap where a change in rock type (stratigraphic trap) or faults/folds in the rock (structural trap) permit the accumulation and retention of the gas. In contrast, nonconventional gas occurs in a continuous bed; however, the permeability of the rock is so low that gas will not flow to a well bore without treatment of the rock formation. The three most widely discussed nonconventional gas sources are coal bed methane, tight sandstones, and gas shale. In the first source, coal bed methane, the coal seam needs to be dewatered before the gas can flow. Thus, water production in coal bed methane is the inverse of that seen for conventional oil and gas—it is very high in the first few years of operation with little gas production and very low in subsequent years. Table 10.2 indicates that between 9 percent and 10 percent of gas production is projected from coal bed methane.

For tight sands and gas shale, the formation will need to be "fractured" in order to allow the gas to flow to the well bore. A pump truck or trucks force a fluid into the well under such great pressure that the formation actually fractures. The fracturing fluid also contains sand, crushed walnut shells, aluminum pellets, or some other material that will prop the fractures open when the pressure on the well is released (Bommer, 2008). Thus, tight sands and gas shale will have at least one episode of water use when the formation is fractured to go into gas production. Tight gas and gas shale are the source for 43 percent to 47 percent of domestic natural gas production in EIA's projections (see Table 10.1). Thus, we attempt to estimate water use in order to determine whether it is large enough to warrant inclusion in the analysis or further refinement.

Table 10.1. Projected Gas Production 2010-2030

	Gas Production (Trillion Cubic Feet)			
	2010	2015	2020	2030
Associated Gas				
Onshore	1.41	1.41	1.36	1.32
Offshore	0.72	0.89	1.01	1.13
Alaska	0.37	0.33	1.14	1.96
Non-Associated Gas				
Onshore				
Conventional	4.68	4.14	3.39	2.21
Gas Shale	2.30	2.62	2.96	4.13
Coalbed methane	1.78	1.75	1.78	2.01
Tight Gas	6.50	6.53	6.60	7.09
Offshore	2.54	2.58	3.17	3.76
Total Production:	20.30	20.25	21.41	23.61

	Percentage of Total Production			
	2010	2015	2020	2030
Associated Gas				
Onshore	6.95%	6.96%	6.35%	5.59%
Offshore	3.55%	4.40%	4.72%	4.79%
Alaska	1.82%	1.63%	5.32%	8.30%
Non-Associated Gas				
Onshore				
Conventional	23.05%	20.44%	15.83%	9.36%
Gas Shale	11.33%	12.94%	13.83%	17.49%
Coalbed methane	8.77%	8.64%	8.31%	8.51%
Tight Gas	32.02%	32.25%	30.83%	30.03%
Offshore	12.51%	12.74%	14.81%	15.93%

Source: EIA (2009b).

Table 10.2. Recent Drilling Activity

Year	API									EIA	
	Total Onshore Wells Drilled			Total Offshore Wells Drilled			Total Wells Drilled			Total Wells Drilled	
	Total Wells	Avg. Depth per Well (ft/well)	Avg. Cost per Foot ($)	Total Wells	Avg. Depth per Well (ft/well)	Avg. Cost per Foot ($)	Total Wells	Avg. Depth per Well (ft/well)	Avg. Cost per Foot ($)	Total Wells	Avg. Depth per Well (ft/well)
2000	23,549	5,081	$94.47	623	11,418	$644.16	24,172	5,245	$125.45	27,873	4,900
2001	31,104	4,988	$117.88	691	11,548	$791.83	31,795	5,130	$150.88	34,021	5,063
2002	23,955	5,264	$135.07	434	12,219	$1,031.10	24,389	5,388	$171.12	26,564	5,269
2003	28,724	5,462	$144.64	505	11,410	$1,231.99	29,229	5,564	$183.32	30,675	5,515
2004	31,528	5,670	$235.98	426	11,645	$1,359.73	31,954	5,750	$266.26	33,096	5,581
2005	37,718	5,645	$236.49	404	11,959	$1,929.43	38,122	5,712	$274.16	40,745	5,586
2006										49,507	5,747
2007										53,558	6,401
Average	29,430	5,352	$160.76	514	11,700	$1,164.71	29,944	5,465	$195.20	37,005	5,508

Source: API (2008) and EIA (2008

10.2.2 Drilling Operations

The analyses presented in this section is based on information from ASME (2004), Bommer (2008), Adams (1985), and OSHA (2009).

When an oil or gas well is drilled, a fluid is pumped down the center of the drilling pipe, out through the drill bit (the cutting face), and back up the annulus of the borehole to the surface. Drilling fluids, also called a drilling mud, can be air-based, water-based, oil-based, or polymer-based. Water-based muds can be made of fresh water or salt water (sea water or saline). The choice of a drilling mud is based on formation characteristics and cost.

The drilling fluid serves several purposes. Among the most important are:

- Cleaning out the borehole by carrying the cut rock back up to the surface for disposal.
- Cooling and lubricating the drill bit.
- Keeping the well bore open under lithostatic pressure.

An onshore drilling site includes steel tanks called “mud pits.” The drilling fluid, typically composed of water primarily mixed with various clays and barite, is mixed and stored before being pumped down the well in one tank. The fluid coming up from the borehole is sent to a mud pit with shale shakers and other equipment to separate the drilling fluids from the drill cuttings to the extent possible before recirculating the fluid. Separated solids and spent drilling fluids are sent to a “reserve pit.” A portion of the fluid coats the particles of the drill cuttings. Because some of the cuttings are too small to separate from the fluid, additional drilling fluid is needed for make-up and dilution purposes. Thus, the volume of drilling wastes (drill cuttings and spent fluids) will be a multiple of the borehole volume.

To supply water for drilling onshore wells, a contractor might (1) drill a well into a shallow aquifer at the site for water or (2) transport water to the site with the rest of the drilling materials and equipment, typically by truck. Diagrams of typical well sites (e.g., Bommer, 2008) show on-site water wells. We have not found data for the proportion of wells for which water must be trucked to the well site, but infer that this happens in a minority of the cases. If a suitable aquifer exists at the drill site, an on-site water well is likely to be the most cost-effective water source. Thus, the majority of the water used for drilling would be ground water.

After the well is completed, the reserve pit might be dewatered using evaporation or dewatering equipment. The solids are typically mixed into the surrounding soil (land application) if they meet the contaminant limits for such disposal. If the pit is actively dewatered, the final disposition of the water depends on its chemical composition. If the water does not meet the limits for land application or beneficial use (e.g., dampening roads for dust control or watering livestock), it is trucked to a Class II injection well for disposal. Note that discharge to surface water is prohibited.

10.2.2.1 Number of Wells Drilled per Year

There are two data sources for the number of wells drilled per year. The American Petroleum Institute (API) bases the well counts published in its Basic Petroleum Data Book on the annual Joint Association Survey on Drilling Costs (API, 2008). EIA used API data up to 1995 when the agency switched to well reports submitted to Information Handling Services Energy Group, Inc. (EIA, 2008). The well data from 2000 through 2005 (API) and from 2000 to 2007 (EIA) are presented in Table 10.2. We can draw several observations from Table 10.2.

- Offshore wells form only two percent of the total wells drilled but are roughly twice as deep and ten times more expensive than onshore wells. Disposal requirements for drilling waste also differ between onshore and offshore wells.

- For the 2000-2005 period, the EIA annual well count averages seven percent greater than the API well count. One reason for the difference might be that API notes that it does not include sidetracks where more than one borehole is diverted off a single well bore (API, 2008).

- The time lag in the API data means that we do not see the sharp uptick in the number of wells drilled in 2006 and 2007 that correlates with the increased oil prices seen at this time. The U.S. spot price for oil was $49.37/bbl at the end of December 2005, $85.52/bbl at the end of December 2007, $131.44/bbl in mid-July 2008, and $31.84/bbl at the end of December 2008 (EIA, 2009c)

For this project, we will use the EIA annual well count because sidetracks will consume drilling fluids. We will use the 2000-2005 average number of wells drilled because this is more indicative of the level of drilling activity at current oil prices. Rounded to the nearest thousand wells, this is 32,000 wells drilled per year (EIA data) compared with 30,000 wells per year (API data).

10.2.2.2 Drilling Methods

API authorized a survey to its membership to collect 1995 data for waste volumes and waste management practices for onshore and coastal exploration and production operations (ICF, 2000). The project was intended to update the findings of a similar survey that collected 1985 data and was published in 1987. To the best of our study team's knowledge, this represents the most recent data publically available. The survey obtained 58 responses representing 1,244 new wells drilled in 1995. Wells are air-drilled (i.e., without the use of a drilling fluid) most commonly in Appalachia, see Table 10.3. These wells amounted to about 11 percent of the wells reported in the survey (no use or consumption of water).

Table 10.3. Percentage of New Wells Drilled with Air or Gas—1995 Data

State	Percentage of New Wells Drilled with Air or Gas
New York	100%
Pennsylvania	100%
Virginia	100%
West Virginia	97%
Kentucky	95%
New Mexico	73%
Ohio	62%
Oklahoma	36%
Utah	22%
Nationwide Percent	11%

Source: ICF (2000), Table E.1.

About 23 percent of the wells were drilled with "closed" systems where no reserve pit is dug. Instead, the spent drilling fluids and drill cuttings are collected in storage tanks. Closed systems are used in environmentally sensitive areas. Closed systems were reported for at least some of the wells drilled in six states (Alaska, California, Colorado, Kansas, Texas, and Utah). All (100%) of the wells drilled in Alaska used closed systems. The use of closed systems will not affect water use but will affect land use by the drilling operation. A closed system would also limit the loss of fluid to evaporation that happens with an open reserve pit (Bommer, 2008). The remaining 66 percent of the wells were drilled with a reserve pit for the drilling fluids and cuttings.

10.2.2.2 Drilling Fluids

10.2.2.2.1 Onshore

Table 10.4 provides a snapshot of on-shore drilling fluid composition by the base fluid as of 1995. Only Alaska shows any substantial use of synthetic drilling fluids (30 percent) while Oklahoma and Louisiana show substantial uses of oil-based fluids (37 percent and 7 percent, respectively). Saltwater-based fluids are reported only for six states—Kansas, Montana, New Mexico, Ohio, Texas, and West Virginia—which have known saline water sources. ICF (2000) estimated that—nationwide—about 92.5 percent of the drilling fluid wastes were freshwater-based while 5.5 percent were saltwater-based. The remaining drilling fluids were oil or synthetic based.

Table 10.4. 1995 Distribution of Base Drilling Fluid Use (Onshore Operations)

State	Percentage of Wastes by Base Fluid				Number of Responses
	Freshwater	Saltwater	Oil	Synthetic	
AK	70%			30%	1
CA	98%		1.5%	0.5%	8
CO	100%				2
IL	100%				2
KS	99%	1%			6
LA	93%		7%		4
MI	100%				1
MT	14%	86%			2
NM	82%	16%		2%	3
OK	63%		37%		2
TX	93%	7%			8
UT	100%				3
WY	100%				1
Appalachian States					
KY					Air drill only
NY					Air drill only
OH	67%	33%			3
PA					Air drill only
VA					Air drill only
WV	83%	17%			1

Source: ICF (2000), Table E.2.

10.2.2.2.2 Offshore

EPA (2000) projects that the distribution of drilling fluids would approach 72.5 percent water-based fluids, 23.8 percent synthetic-based fluids, and 3.6 percent oil-based fluids. We have not found data that identifies the proportion of water-based muds that are made with seawater for offshore drilling operations. However, for cost reasons, we suspect that most would be made with the readily available seawater.

10.2.2.3 Disposal Practices for Liquid Drilling Wastes

10.2.2.3.1 Onshore

Based on the reported volumes of drilling wastes and disposal methods reported in the 1995 survey, ICF (2000) estimated nationwide patterns for onshore drilling operations. The drilling waste consisted of 27 percent solids and 73 percent liquids by volume. Table 10.5 summarizes the disposal methods for the 73 percent liquid wastes, the national percentage, and the states in which the methods were reported. Nearly half of the liquid wastes are evaporated. Another 13 percent are injected either into a formation or left in the annulus (i.e., the space between the drill pipe and the well bore or between the tubing and the casing (Bommer, 2008)).

Table 10.5. Onshore Disposal Methods for Liquid Drilling Wastes

Disposal Method	Percent		States in which Used / Comments
	Total	Liquid	
Evaporate on or off site	47%	64%	Disposal in Texas drives the nationwide percentage of liquid drilling wastes that are evaporated. Texas reported nearly half of the liquid drilling wastes in the survey and, of these, slightly over 80 percent were evaporated. Other states reporting evaporation are: California, Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Utah, and Wyoming.
Reuse for drilling	7%	10%	California, Kansas, Louisiana, Montana, Oklahoma, Texas, and Utah
Injected down annulus	7%	10%	Only Louisiana reports this practice.
Injection	6%	8%	Alaska, Arkansas, Colorado, Illinois, Kansas, Louisiana, Montana, New Mexico, and Texas
Land application and road spread	4%	5%	California, Louisiana, Michigan, New Mexico, Texas, Kentucky, Virginia, and West Virginia. Only Texas reports road spreading.
Treat and discharge	1%	1%	Kentucky and West Virginia
Other	1%	1%	California and Pennsylvania
Total (Liquid Wastes)	73%	100%	

Source: ICF (2000), Table E.8

10.2.2.3.2 Offshore

In addressing offshore disposal, we focused on the 72.5 percent of offshore wells drilled with water-based fluids. EPA (1993) reports that approximately one percent of water-based drilling fluids to which no oil has been added would fail a toxicity test. These drilling wastes would need to be collected and transported to shore for treatment and disposal (e.g., treated like oil- and synthetic-based fluids). While EPA (1993) also reports that four percent of wells drilled with water-based fluids had diesel oil added to the fluids for lubricity purposes, this is based on 1984 survey data. It is highly likely that mineral oil is used instead of diesel oil in current practices to minimize the costs of transporting the fluids to shore. Thus, we consider 99 percent of the liquid wastes from water-based fluids to be discharged.

10.2.2.4 Liquid Drilling Waste Volumes

10.2.2.4.1 Well Bore Volume

Based on the information in Table 10.4, we assume that a typical onshore well is 5,400 feet deep while a typical offshore well is 11,700 feet deep. We estimate the amount of liquid drilling wastes in two steps:

- Calculate the estimated total volume of the wellbore, as the sum of cylinders with different diameters over a specified distance ($\Sigma \Pi r^2 L$)
- Estimate the amount of drilling fluid based on the amount of fluid needed to maintain an acceptable level of solids contamination in the fluid.

Table 10.6 presents typical wellbore architectures for a 5,400-foot and 11,700-foot well based on Bommer (2008) and PACNR (2002). The conversion factor is 0.1781 barrels per cubic foot. The wells are spudded with 15 inch or 16 inch holes for the first 150 feet. The onshore well is drilled with a 11 ¾ inch drill bit from 150 feet to 2,000 feet, a 9 ⅞ inch drill bit from 2,000 feet to 3,500 feet, and a 7 ⅞ inch drill bit from 3,500 feet to the final depth of 5,400 feet. A similar pattern of drilling, casing, and continuing with a smaller drill bit is shown for the hypothetical offshore well. The volume of each interval is calculated and summed to estimate the volume of the well bore. The calculated volumes are adjusted upwards by 7.5 percent based on "washout" or the sloughing of material from the walls of the well bore (EPA, 2000). The volumes range from about 577 barrels to 1,385 barrels.

Table 10.6. Estimated Well Volumes

Depth Interval	Borehole Diameter (in)		Hole Volume (bbl)	
(ft from surface)	Onshore	Offshore	Onshore	Offshore
150	15.000	16.000	33	37
2,000	11.750	13.500	248	328
3,500	9.875	13.500	142	266
5,400	7.875	9.875	114	180
9,700		9.875		407
11,400		6.500		70
Total Hole Volume			537	1,288
Assumed Washout Fraction (7.5%)			577	1,385

Sources: Bommer (2008), ASME (2005), and EPA (2000).

10.2.2.4.2 Estimated Volume of Liquid Drilling Fluid Per Well

ASME (2005) notes that the total volume of waste drilling fluid can be estimated as:

$$L = HV \times (1-\varepsilon) / T$$

where:

L = liquid discard (bbl)

HV = Hole volume (bbl)

ε = efficiency of solids control, expressed as a fraction

T = Tolerance of the fluid system to solids contamination, expressed as a fraction

The volume of liquid discharge is strongly affected by the combination of the efficiency of the solids-control system and the tolerance of the drilling fluid to solids added by the drill cuttings. Table 10.7 shows the volume of liquid discharge for a 1 unit hole volume under a range of typical values for solids removal efficiencies and drilling fluid tolerances taken from ASME (2005).

Overall, the ratio ranges from 14:1 to 3:1. Thus, the volume of discharge liquid for an onshore well could range from 1,731 barrels (577 times 3) to 8,078 barrels (577 times 14). For the purpose of this analysis, we use a 7:1 ratio that reflects the mid-range values in Table 10.7. The estimated volume of liquid discharge is thus about 4,039 barrels for an onshore well and 9,695 barrels for an offshore well.

Table 10.7. Sensitivity of Volume of Discharged Liquid to Solids Removal Efficiency and Drilling Fluid Tolerance to Solids

Solids Removal Efficiency	Drilling Fluid Tolerance to Solids		
	5%	7%	10%
30%	14	10	7
50%	10	7	5
70%	6	4	3

Unit Hole volume is 1 bbl

10.2.2.4.3 Annual Volume of Liquid Drilling Waste

Table 10.8 combines the information presented in the earlier sections to provide an estimate of the annual volume of liquid drilling wastes and their disposition. The number of wells is taken from the EIA estimates (Table 10.2) while the volume of fluid per well drilled is estimated as discussed above. Overall, the estimate is about 132.9 million barrels of liquid. We have left the disposition of the water in as much detail as possible to allow other users to evaluate what is consumed and what is used.

Table 10.8. Estimated Annual Volumes and Disposition of Liquid Drilling Waste

Location	Annual Number of Wells	Estimated Volume of Liquid Drilling Wastes per Well (bbls)	Estimated Volume of Liquid Drilling Wastes per Year (bbls)	Disposition Method	Percent	Liquid Drilling Wastes (bbls)
Onshore	31,360	4,039	126,663,040	Evaporate on or off site	64%	81,550,176
				Reuse for drilling	10%	12,145,771
				Injected down annulus	10%	12,145,771
				Injection	8%	10,410,661
				Land application and road spread	5%	6,940,441
				Treat and discharge	1%	1,735,110
				Other	1%	1,735,110
Offshore	640	9,695	6,204,800	Transported to shore	1%	62,048
				Treat and discharge	99%	6,142,752
Totals	32,000		132,867,840			132,867,840

10.2.3 Fracturing Operations

10.2.3.1 Number of Wells Fractured Per Year

In its 2009 resolution to keep the exemption of hydraulic fracturing fluids in the provisions of the Safe Drinking Water Act, the Interstate Oil and Gas Compact Commission (IOGCC) states that approximately 35,000 wells are fractured each year (IOGCC, 2009). This is the only estimate that has yet been identified. It is on the same order of magnitude as the number of wells drilled per year, as discussed above. This does not mean that all wells are fractured at the time they are drilled. Some wells are fractured later in their productive life to enhance continued production. On the other hand, wells drilled into tight shale, tight gas, and coal bed methane formations require fracturing in order to connect the wellbore to the network of fractures within the geological layer (EPA, 2004).

10.2.3.2 Water Volume

Table 10.9 lists the results of a literature search for the water volumes associated with fracturing nonconventional gas wells. The amount of water used to fracture a well in a tight shale formation appears to be 10 to 20 times larger than the amount used to fracture a well in a coal bed methane formation. In other words, the distribution of fracturing jobs among the different formations will have a substantial effect on the nationwide amount of water assumed to be used in fracturing. The volume of water used per well ranges from 50,000 gallons to 3,000,000 gallons. Using the IOGCC estimate of 35,000 wells fractured per year, this represents between 1.75 billion to 105 billion gallons of water or 41.7 million to 2,500 million barrels of water.

Table 10.9. Well Fracturing Volumes

Formation	State	Volume (gallons)	Source
Barnett Shale	TX	2,000,000	IOGCC and ALL (2006)
Marcellus Shale	PA	1,000,000 to 3,000,000	PADEP (2008)
Marcellus Shale	NY	3,000,000 (average)	NYSWRI (2009)
Coalbed Methane		50,000 to 350,000	Literature cited in EPA (2004)
Coalbed Methane		150,000 (maximum)	Halliburton cited in EPA (2004)
Coalbed Methane		57,500 (median)	Halliburton cited in EPA (2004)

Some of the fracturing fluid is recovered when the pressure is relieved. Recovery fractions for coal formations were estimated at about 60 percent and from 31 to 46 percent for non-coal formations (EPA, 2004). Information identifying the source of the water has not been found by our study team; however, for economic reasons, the water source is likely to be located as close as possible to the drilling site (NYSWRI, 2009). Thus, it is likely that the majority of the water comes from groundwater sources. The use of groundwater from nearby locations also maximizes the probability that the water will not interact unfavorably with the petroleum-bearing stratum.

10.2.4 Production Operations

As described above, water comes up the wellbore along with the oil. The following scenarios are possible for a well in the production phase:

- Very little water is produced and none is injected. This would describe a conventional gas well, an oil well at the beginning of its productive life, and, possibly, tight shale and tight gas wells.
- Water is produced and none is injected (e.g., a coal bed methane well in its early years or an oil well in primary production.)
- Water is produced from and injected into the same geologic formation (e.g., secondary and tertiary production from oil wells).
- Water is produced from and injected into the same geologic formation, but additional water is needed for effective secondary and tertiary production from oil wells.

Under primary recovery, oil or gas flows into the well because the pressure in the producing stratum or reservoir is higher than the pressure in the well bore. Only about 10 percent to 15 percent of the oil in place is recovered under primary recovery (Schlumberger, 2009). Two common methods to maintain reservoir pressure and drive some of the remaining oil into the well is to inject gas into the gas cap (if the formation has one) or water into the production stratum. The first method is called gas injection or pressure maintenance while the second method is often called "water flooding." Water flooding is rarely used for gas-only fields (Rottman and Crutchfield, 1998).

Tertiary recovery (also called enhanced oil recovery) involves improving the oil flow by chemical or thermal treatment. Although there will be some water use in tertiary recovery (e.g., steam injection), the volume is likely to be a small fraction of that used for secondary recovery.

One parameter that is of interest is the total amount of produced water generated during oil production and the disposition of that water. To complete the analyses, therefore, injection water that is not produced water needs to be included. In examining data in the literature review, it is important to note that different studies use different definitions for water use. These differences are discussed in more detail below.

10.2.4.1 Argonne National Laboratory

Argonne National Laboratory released a report of consumptive water use in the production of ethanol and petroleum gasoline in January 2009 (Wu et. al, 2009, hereafter called the "ANL report"). The major assumptions and findings include:

- Only the water needed for injection is considered as consumed.
- Net consumption is the difference between the volume of water needed for domestic onshore production and the volume of produced water that is injected for oil recovery.
- The average weighted injection volume is 8:1 (gallon water/gallon crude).

- The net average weighted injection volume is 3.2:1 (gallon water/gallon crude).

The ANL report mentions three assumptions where additional information can be used to refine the analysis. First, the ANL report treats all offshore production as primary production. We present offshore produced water information below that includes both water that is produced and that which is reinjected. Second, the ANL report mentions that the disposition of produced water shown in Wu et al., (2009), Figure 28 includes water produced from coal bed operations. Additional information on conjoined coal bed methane and water production is provided below. We also make the argument that water from coal bed methane operations should be removed from the water-to-oil ratio calculations and that a separate water-to-gas ratio should be included in life cycle analyses.

Third, the average weighted injection volume of 8 gallons of water per gallon of crude oil is driven by the 8.6 gallons of water per gallon of crude oil reported for secondary recovery (see Wu et al. (2009), Table 8). The 8.6 value is taken from a 1968 report and it considers the volume of water needed to drive the front edge of the water to the well. In effect, the calculation estimated the volume of water needed to fill the reservoir once. It does not address the water production that happens once "break through" occurs and the injected water starts coming up the borehole. Once "break through" happens, the volume of water production increases sharply because the reservoir is being filled multiple times as the oil is washed off the rock and carried to the well bore. There are fields in the U.S. where water forms more than 90 percent of the fluid that comes up the wellbore (also called 90 percent watercut), see CADOC (2007) for examples.

10.2.4.2 USGS Estimated Water Use in the United States in 2000

USGS (2004) reports that oil and gas operations in Alaska, California, Oklahoma, Texas, and Wyoming were responsible for large withdrawals of saline water from groundwater sources. Project staff staff contacted USGS to find out whether the Agency had a subset of the mining industry data with only the oil and gas operations. Such data are not available and the USGS recommended contacting each State USGS. USGS contacts in all five states mentioned that the oil and gas data were supplied by the state government agency that regulates oil and gas production in the state. The state contact for Wyoming provided additional information on what is contained in the estimated water use data.

- Water pumped and then injected for secondary recovery is considered a water use and counted.
- Unless water pumped from a mine (or oil and gas operations) is put to beneficial use, it is not included.
- Produced water that is injected for disposal is not considered a beneficial use and is thus not included (Boughton, 2009).
- Water pumped and discharged without being put to use is considered a ground water to surface water transfer and is not included (Boughton, 2009).

Thus, for the purposes of this project, the USGS data might not contain all aspects of water production associated with oil and gas operations. For example, USGS (2004), Table 11 reports mining water withdrawals of 177 million gallons per day or approximately 1,538 million barrels per year for California in 2000 (USGS, 2004). Because the USGS data is for all water withdrawals for all mining operations, it is assumed that the California data should be less than that reported in USGS (2004). USGS includes re-injecting extracted water for secondary oil recovery as mining water use (USGS, 2004). The California State Oil & Gas Supervisor produces an annual report that includes the volumes of water produced and injected. The report for 2000 states that 1,863 million barrels of water were produced from onshore oil and gas operations while 1,490 million barrels of water were injected for waterflood, steamflood, cyclic steam, and disposal. If the 1,490 million barrels of water represents the oil and gas portion of the 1,538 million barrels of water use reported for California mining operations, then the question arises on whether and how to consider the additional 373 million barrels that came up with the oil and gas but were not reinjected. Presumably, this amount of water should be incorporated into the life cycle analysis. If so, then the information provided in the USGS Estimated Use of Water series might be an underestimate for the purposes of this project.

10.2.4.3 Produced Water from Onshore Oil and Gas Operations

Table 10.10 lists some of the water-to-oil ratios reported in the literature. The ratio appears to be increasing in time, which is consistent with the known behavior of individual oil fields and wells. The lowest figure, 5 to 1, is reported in the 1985 survey data in ICF (2000). The most recent values cluster just beneath a 10 to 1 water-to-oil ratio (see USGS, 1997; IOGCC and ALL, 2006; and Veil et al. 2004).

In contrast, Wu et al. (2009) examines the amount of water that needs to be injected in order to produce a barrel of oil. This amount is then reduced by the fraction of the produced water that is injected for secondary recovery. The result is presented as the net water consumption per barrel of oil. A more accurate description would be the additional barrels of water that must be withdrawn from another source to produce a barrel of oil via waterflooding. The approach omits the more than 20 percent of produced water that is injected for disposal.

Finally, the inclusion or exclusion of produced water in the estimates of water use for oil production needs to be clearly identified before a water-to-oil ratio is used in further analyses. For example, Wu et al. (2009) subtracts out the injection of produced water to calculate a net water use. In contrast, USGS counts the injection of produced water for secondary recovery as a use unless the injection purpose is disposal.

Table 10.10. Onshore Water to Oil Ratios on a Volume Basis: Literature Review

Water/Oil, volume basis (Year, if mentioned)	Source	Comments
10	USGS, 1997	No underlying citation.
7.5 (2000)	IOGCC and ALL, 2006	Data collected from 37 IOGCC member and associate member states.
9.8 (2005)		
5.0 to 6.4 (1985)	ICF, 2000	Survey data.
7.5 (1995)		
9.5 (2002)	Veil et al., 2004	Page 7.
6.8 (2002)		As calculated from the data in Tables 3-1 and 3-2.
8	Wu et al., 2009	Water needed for onshore injection, Table 9.
3.2		Net water consumption based on 6.8 bbls injection water needed to produce 1 bbl oil reduced by the fraction of produced water injected for oil recovery (71%)

ICF (2000) provides a breakout of the disposition of produced water from onshore operations as follows:

- 71 percent injected for enhanced oil recovery
- 21 percent injected for disposal
- 3 percent disposed in percolation ponds (This practice is reported only by California.)
- 3 percent is treated and discharged
- 2 percent is associated with beneficial use

Beneficial use takes place under National Pollutant Discharge Elimination System (NPDES) permits that allow produced water from conventional and nonconventional sources to be used for irrigation, livestock watering, and similar uses. A footnote mentions that over 99 percent of the produced water that is treated and discharged is from coal bed methane operations in Alabama. Presumably, the disposition of produced water from coal bed methane operations in Wyoming is included under beneficial use. Removing coal bed methane releases from consideration with oil production results in the following distribution:

- 73.2 percent injected for enhanced oil recovery
- 21.6 percent injected for disposal
- 3.1 percent disposed in percolation ponds
- 2.1 percent has beneficial use

A refinement of the ANL study would use the modified percentages in its calculations.

10.2.4.4 Produced Water from Offshore Oil and Gas Operations

As mentioned above, the ANL report assumes that all offshore production is primary production. Below, additional information about water injection in the offshore regions is provided in order to evaluate whether this assumption needs to be modified. This section will not be comprehensive but will cover major states and regions and includes a discussion of the Federal offshore regions managed under the Minerals Management Service as well as state-controlled offshore regions.

10.2.4.4.1 Federal Offshore Waters

The Gulf of Mexico regional office for Minerals Management Service makes production data available in the OGORA files. Table 10.11 lists three years of data for the Federal Gulf of Mexico. The percentage of produced water that is injected climbs from about 8 percent to nearly 10 percent over the three year period. The water-to-oil ratio ranges from 1 barrel of water per barrel of oil to 1¼ barrels of water per barrel of oil.

Table 10.11. Oil, Gas, and Water Production in the Federal Gulf of Mexico 2006-2008

Year	Oil Production Volume (bbls)	Gas Production Volume (Mcf)	Water Production Volume (bbls)	Injection Volume (bbls)	Percent of Produced Water Injected	Water/Oil Ratio
2006	471,854,783	2,930,613,949	488,956,655	38,843,233	7.94%	1.04
2007	467,246,285	2,814,316,136	593,465,370	52,694,444	8.88%	1.27
2008	395,979,951	2,145,547,805	473,661,736	46,656,915	9.85%	1.20

Source: MMS (2009)

Table 10.12 shows comparable data for water production and injection for the Pacific Outer Continental Shelf region off California for 2000, 2006, 2007, and 2008. The 2008 data are based on preliminary estimates and injection data are not yet available. The percentage of produced water that is injected for secondary recovery ranges from 21 percent in 2000 to 34 percent in 2007. The water-to-oil ratio climbs from 2 in 2000 to 5 in 2008.

Table 10.12. Oil and Water Production in the California Federal Offshore

Parameter	Year			
	2000	2006	2007	2008
Water Produced (bbls)	76,825,519	97,222,060	103,344,299	114,000,000
Water Injected for Recovery (bbls)	16,101,215	26,633,346	34,716,532	
Percent of Water Injected	21%	27%	34%	
Oil Production (bbls)	35,918,425	26,248,797	24,696,813	24,100,000
Water/Oil ratio (bbls:bbl)	2	4	4	5

Source: CADOC (2000, 2006, 2007, and 2008).

10.2.4.4.2 State Offshore Waters

Rabalais (2005) reports the following produced annual water volumes discharged from Louisiana and Texas territorial waters as:

- Louisiana: 186,000,000 bbls
- Texas: 4,300,000 bbls

The volume of water produced in the narrow band of state waters is about half to one-third of the volume produced in the Federal Outer Continental Shelf region. This is consistent with the age of the fields and, given the age of some of the offshore production, it is likely that some of the fields are in secondary production. Unfortunately, the study team has been unable to identify a source for the amount of secondary production in these offshore regions.

Table 10.13 summarizes the volumes of water produced and injected in California offshore waters. In some fields, additional water must be brought to the site for injection because the volume of fluid injected exceeds the volume of produced water. Because some produced water is injected for disposal, the fields needing the additional water for recovery are not located close enough to fields with excess produced water for it to be cost-efficient to transport the excess water. The water-to-oil ratio nearly doubled from 2000 to 2008 from 16 to 1 to 31 to 1.

Table 10.13. Produced Water Generation and Injection in California State Offshore Waters

Parameter	Year			
	2000	2006	2007	2008
Water Produced (bbls)	299,282,297	370,581,580	387,974,900	389,000,000
Water Injected (bbls)				
Disposal	439,098	2,334,895	430,755,430	
Waterflood	329,245,043	407,549,248	4,097,590	
Steam Flood	910,374	2,104,256	0	
Cyclic Steam	146,822	0	387,974,900	
Water Injected for Recovery (bbls)	330,302,239	409,653,504	392,072,490	
Water Injected for Disposal (bbls)	439,098	2,334,895	430,755,430	
Percent of Water Injected for Recovery	110%	111%	101%	
Oil Production (bbls)	18,323,992	15,075,662	14,677,995	12,500,000
Water/Oil ratio (bbls:bbl)	16	25	26	31

Source: CADOC (2000, 2006, 2007, and 2008).

10.2.4.5 Observations

Wu et al. (2009) assumes that all offshore production is primary production and no water is injected for oil recovery. Wu et al. (2009) Table 9 is accurately titled “Water Injection in U.S. Onshore Production by Recovery Technology” and is the source of the 8 to 1 water-to-oil ratio presented in Table 11 above. The 8 to 1 ratio and the 3 to 2 net water-to-oil ratio are representative of onshore production only.

One third of the nation’s oil is produced in the state and federal offshore regions. Thus, the life cycle analysis should incorporate offshore oil production data to the extent possible. As the data above indicate, the percent of produced water injected in offshore regions varies by region:

- Federal Gulf of Mexico—8 to 10 percent
- Federal Pacific—27 to 34 percent
- California—100 percent and more

IOGCC and ALL (2006) examine the trends in water production associated with natural gas. From 2000 to 2005, water production increased from 0.75 barrel of water per 10^3 cubic feet (Mcf) gas to about 1.0 barrel of water per 10^3 cubic feet of gas.

EPA is currently conducting a preliminary study of coalbed methane operations and collected water and gas production volumes (Table 10.14). The 2006 average water-to-gas ratio is 0.56 bbl water to 1 Mcf gas. On an energy basis, 1 Mcf gas is equivalent to 0.1767 barrel of oil. On a barrel-of-oil-equivalent (BOE) basis, the ratio is 3.18 barrels of water per BOE.

Table 10.14. Produced Water Volumes from Coalbed Methane Operations

State	Total 2006 Water (bbls)	Total 2006 Gas (Mcf)	Total 2006 Barrel of Oil Equivalent [BOE] (bbls)*
AL	60,410,483	115,997,777	20,496,807
AR		2,454,197	433,657
CO	187,058,058	513,959,781	90,816,693
KS		23,579,537	4,166,504
LA	956,319	137,648	24,322
MT	29,769,067	11,728,448	2,072,417
NM	35,437,601	531,914,721	93,989,331
OH		321,749	56,853
OK		47,601,639	8,411,210
PA**		1,218,438	215,298
TX	48,550	187,148	33,069
UT	23,459,018	76,663,825	13,546,498
VA	2,104,097	74,423,030	13,150,549
WV		19,019,647	3,360,772
WY	676,622,166	389,990,277	68,911,282
Total	1,015,865,359	1,809,197,862	319,685,262

*1 Mcf of gas = 0.1767 bbls of oil
** Data from Pennsylvania is from 2001. Pennsylvania holds certain data as confidential for five years.
Source: Smith (2008).

Wyoming provided data for 2000 (Boughton, 2009). Coalbed methane production was 150.7 million Mcf with 378.8 million barrels of water for a water:gas ratio of 2.5 barrels of water per 1 Mcf of gas or 14.2 barrels of water per 1 BOE. In 2006, Wyoming had a 1.7 barrels of water per 1 Mcf gas ratio (see Table 10.145). The decline in water production and increase in gas production over time is characteristic of coalbed methane operations.

10.3 Summary

There is considerable variability in the amount of water used in petroleum and gas drilling, fracturing and production. For the purposes of this work, we will rely on the ANL (2009) analyses, derived from on on-shore production, of roughly 3 bbl of net water use per bbl of domestic oil production. We note however, that if water use during annual drilling and fracturing activity is added to this estimated water use for production, then the amount of annual water use in domestic oil production will be increased by 200-2000 million bbl/yr. Based on domestic production of 2000 million bbl/yr (EIA, 2009a), this would increase the estimate of water use, based only on production, by 3-30%.

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