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Comparison of Water Use for Hydraulic Fracturing for Unconventional Oil and Gas versus Conventional Oil

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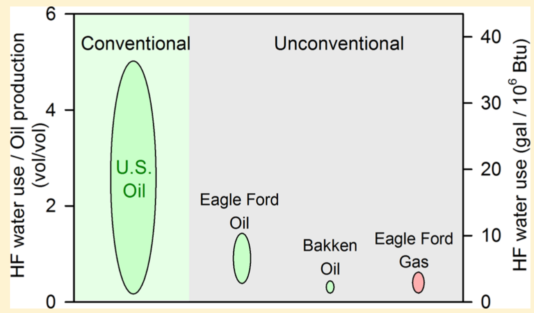
Supporting Information

ABSTRACT: We compared water use for hydraulic fracturing (HF) for oil versus gas production within the Eagle Ford shale. We then compared HF water use for Eagle Ford oil with Bakken oil, both plays accounting for two-thirds of U.S. unconventional oil production in 2013. In the Eagle Ford, we found similar average water use in oil and gas zones per well ($4.7-4.9 \times 10^6$ gallons [gal]/well). However, about twice as much water is used per unit of energy (water-to-oil ratio, WOR, vol water/vol oil) in the oil zone (WOR: 1.4) as in the gas zone (water-to-oil-equivalent-ratio, WOER: 0.6). We also found large differences in water use for oil between the two plays, with mean Bakken water use/well (2.0×10^6 gal/well) about half that in the Eagle Ford, and a third per energy unit. We attribute these variations mostly to geological differences. Water-to-oil ratios for these plays (0.6–1.4) will further decrease (0.2–0.4) based on estimated ultimate oil recovery of wells. These unconventional water-to-oil ratios (0.2–1.4) are within the lower range of those for U.S. conventional oil production (WOR: 0.1–5). Therefore, the U.S. is using more water because HF has expanded oil production, not because HF is using more water per unit of oil production.



■ INTRODUCTION

Unconventional oil production using hydraulic fracturing (HF) with mostly horizontal wells in shales and tight formations (e.g., sandstones and limestones) has greatly increased U.S. oil production (Supporting Information (SI) Figure S1) from ~12% of onshore crude oil production in 2008 to ~35% in 2012, and is projected to increase to almost 50% by 2019.[1] The low permeability of these plays, generally <0.1 millidarcy, requires HF using large volumes of water under high pressure to produce oil or gas, and horizontal wells to increase contact area.[2] Public perception of HF is that it uses extremely large quantities of mostly fresh water, underscoring the importance of quantifying water use for HF. Increasing data availability on water use resulting from regulatory requirements facilitates more detailed quantification of HF water use; however, the reliability of these data needs to be evaluated. Does HF for unconventional oil production use more water per unit of energy than conventional oil production? Alternatively, does higher water use for HF simply reflect increased oil production?

Many previous studies on hydraulic fracturing have focused on water use for gas production in shale plays, including the Marcellus and Barnett shale plays.[3−6] Comparison of life cycle water use showed that HF for unconventional shale gas is more water intensive per unit of energy (4–10 gal/10^6 British thermal units, Btu) than conventional gas production (~3 gal/10^6 Btu).[3] A recent comprehensive assessment of HF water use in all major shale gas and shale oil plays in the U.S. suggests that shale gas production is more water intensive than shale oil production because of higher average HF water use per well in gas-dominated plays, such as the Eagle Ford, relative to oil-dominated plays, such as the Bakken and Permian basin.[7] Shale oil should be distinguished from oil shale, which is solid and yields oil from destructive distillation whereas shale oil is extracted using unconventional production similar to shale gas, HF, and mostly horizontal wells.

Unconventional production has shifted in recent years from predominantly dry gas plays, such as the Barnett and Marcellus plays, to more oil-rich areas of plays (e.g., parts of the Eagle Ford) or to oil-rich plays (Permian and Bakken). The shift has occurred in response to annual average oil prices being up to 4–6 times higher per unit of energy relative to gas prices in 2012 and 2013 (SI, Figure S2). Rising oil prices result from oil being a global commodity whereas natural gas prices are mostly controlled by domestic markets with declining prices related to overproduction in the U.S. Does water use for shale oil production differ from that for shale gas production as suggested previously?[7]

Assessing spatial and temporal variability in HF water use requires an understanding of all potential factors that can impact it. Typical factors controlling HF water use include: type of well (vertical vs horizontal); length of horizontal wells or

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laterals; number of HF stages; and HF fluid types (e.g., slickwater, X-link gel, or hybrids).[6,8,9] Water use for HF is often represented on a per well basis, or per unit length of horizontal well or lateral. Water use per unit of energy produced in oil and gas wells requires data on energy production to date and projected energy production over the life of the well (estimated ultimate recovery, EUR). Water use for HF occurs upfront during well completion; therefore, water use/unit of energy continually decreases throughout the well lifetime, typically 20−30 years.

Because the primary purpose of HF water use is to increase energy (oil or gas) production, it is important to quantify how much water is used per unit of energy produced. Increasing trends in HF water use may be considered reasonable if they result in increased energy production. Quantifying HF water use relative to oil and gas production is also important because the 4−6 times higher prices for oil relative to gas affects the economic value of the water used. To estimate water use per unit of energy the varying energy contents of different hydrocarbon (HC) products from oil and gas reservoirs need to be considered (SI, Section 4).

Hydrocarbons generally exist as either oil or gas under the high temperatures (T) and pressures (P) found in reservoirs (SI Figure S3). When oil and gas are brought to the surface, the decreasing pressures and temperatures can result in phase changes causing gases to bubble out of liquids and liquids to condense out of gases. Gas, primarily methane, that bubbles out of oil is termed "associated gas". Longer chain hydrocarbons (C2−C5+) generally partition into the oil phase and the product is termed "volatile oil" reflecting oil rich in dissolved gas. Gas at the surface can include dry gas (one carbon in the CH_4 molecule, designated C1), typical of many shale plays, such as the Barnett or Marcellus. However, some plays produce wet gas (C2−C5+) and liquids condense from wet gas either at the well head, termed gas condensates or simply condensates (C5+), or at natural gas plants, termed natural gas liquids (NGLs, C2−C4).[10] Wet gas from gas wells produces an estimated 2.5−12 gal NGL/10^3 ft^3 of gas.[10] Therefore, there can be a continuum from dry gas (CH_4) through NGLs and condensates produced from gas wells to volatile oil and black oil from oil wells. Gas represents higher thermal maturity associated with increasing burial depth than oil because energy is required to break or "crack" the carbon bonds to produce shorter chain hydrocarbons.

Estimating water use per unit of energy is relatively straightforward for oil and gas because production data are reported and energy contents can be estimated. Reporting of water use per unit of energy is complicated because of the range of units for water and energy and English and metric versions. Using a ratio of volumes of water and oil (water-to-oil ratio, WOR), or the volume of oil equivalent to a gas volume (water-to-oil-equivalent ratio, WOER) eliminates units. The energy content of oil is $\sim 5.8 \times 10^6$ Btu/barrel [bbl] of oil (or 0.14×10^6 Btu/gal of oil) and of dry gas is 1×10^6 Btu/10^3 ft^3 of dry gas. Therefore, the volume of gas (e.g., 1×10^3 ft^3)can be converted to an equivalent volume of oil (e.g., 0.17 barrel of oil equivalent (BOE), or 7.24 gallons of oil equivalent (GOE). However, estimating water use per unit of energy is more complicated for intermediate products because there are no reporting requirements for NGL or condensate volumes and energy contents vary with composition (C2−C5+), which are also not reported.

How does water use for unconventional oil production compare to that for conventional oil production? Conventional reservoirs are generally high permeability reservoirs where fluids move from source rocks to reservoirs and are generally contained by some type of geologic trap.[11] Oil is produced from conventional oil reservoirs whereas gas can be produced from conventional gas reservoirs (nonassociated gas) or from conventional oil reservoirs as dissolved associated gas.[11] Conventional gas production is generally not subjected to secondary or tertiary production techniques. Conventional oil can be produced through three stages, including primary, secondary, and tertiary production. Primary oil and gas production generally relies on reservoir pressure and only requires water for well drilling (water use to oil production ratio, WOR: ~0.2 v/v).[12,13] This use of WOR should be distinguished from typical use of WORs by the oil industry that represent the ratio of the volume of water produced along with the oil (produced water) to the volume of oil produced, or similar to the concept of water cut. Secondary oil production is used when reservoir pressures decline and generally involves water flooding whereas tertiary production generally includes use of steam or CO_2 in enhanced oil recovery (EOR). Water use mostly increases throughout the lifetime of conventional wells; however, volumes of produced water also increase over time, often resulting in 10−20 times or up to 50 times more produced water relative to produced oil. This produced water is often reused for secondary or tertiary oil recovery.

The objectives of this study were to address the following questions:

1. What is the availability and quality of data on HF water use for shale oil and gas production?
2. How does HF water use vary for unconventional oil versus gas production?
3. How does HF water use for oil production vary among unconventional oil plays?
4. How does water use for unconventional oil production compare to that for conventional production?

(1) Data on HF water use from several sources were compared to assess data reporting and reliability of the individual databases. (2) Comparison of HF water use for unconventional oil versus gas production was based on data from a single play, the Eagle Ford Shale in Texas, because the Eagle Ford is one of the few plays with large volumes of oil produced (ranked first in the U.S. in 2013, SI Figure S1) and gas produced (ranked fourth in the U.S. in 2013). Comparisons within a single play should minimize variations in other factors that might impact HF water use. (3) HF water use in oil zones in the Eagle Ford was compared to that in the Bakken unconventional oil play (99% of wells are oil wells) in N. Dakota and Montana, which ranked second in terms of unconventional oil production in 2013 (SI Figure S1). Both the Eagle Ford and Bakken plays accounted for two-thirds of unconventional oil production in 2013.[1] We did not compare to the Permian Basin because it is markedly different from the Eagle Ford and Bakken, with multistacked plays and mostly vertical wells. (4) We also compared water use for unconventional oil production in the Eagle Ford and Bakken plays to water use in conventional oil production based on data for the U.S. This comprehensive evaluation of HF water demand relative to energy production should be very valuable for future studies assessing water supplies for HF and on economic and policy studies on HF.

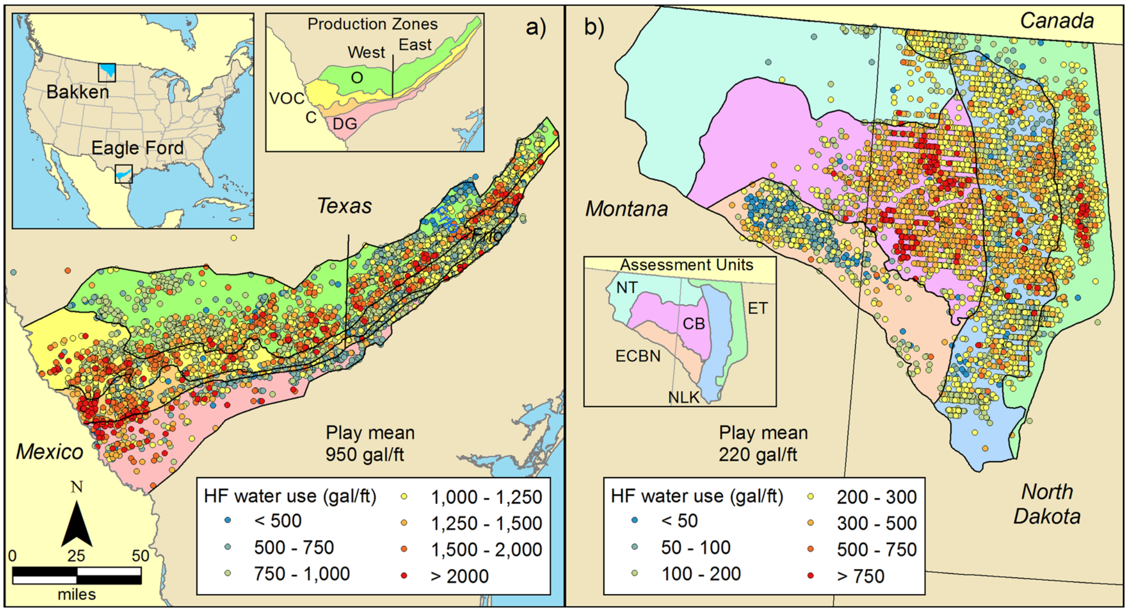

Figure 1. Maps of the (a) Eagle Ford and (b) Bakken plays showing hydraulic fracturing (HF) water use per length of lateral for oil and gas wells. The Eagle Ford play area includes oil (O), volatile oil-condensate (VOC), condensate (C), and dry gas (DG) zones,[17] with the O, VOC, and C zones further divided into West and East regions. HF water use is shown for 8301 wells in the Eagle Ford drilled in 2009−2013. Mean HF water use is higher in the West (1020 gal/ft of lateral) than in the East (840 gal/ft of lateral) (SI Table S8). The Bakken Play includes the Northwest Transitional (NT), Eastern Transitional (ET), Central Basin (CB), Nelson-Little Knife (NLK), and Elm Coulee-Billings Nose (ECBN) assessment units.[18] HF water use for the Bakken includes 7868 wells drilled in 2005−2013 in both the Bakken and Three Forks formations. Mean HF water use in the Bakken is 220 gal/ft of lateral, ranging from 100−320 gal/ft of lateral among the different assessment units (Table 1).

■ MATERIALS AND METHODS

Eagle Ford Shale Play. Energy production from the late Cretaceous Eagle Ford Formation is concentrated within a 9500 mi^2 (24 600 km^2) area that includes 99% of the HF wells (Figure 1a). The Eagle Ford "shale" is a carbonate-rich mudrock, with up to 70% calcite, which makes it brittle and amenable to fracturing. The low permeability of the Eagle Ford shale requires unconventional techniques to produce oil and gas, including HF and horizontal drilling.[14] The Eagle Ford shale has been subdivided into lower and upper units, with the lower unit extending across the entire region, ranging from ∼10 ft thick in the east to ∼200 ft thick in the west.[14] The upper unit is restricted to the western region and is up to 480 ft thick at the western boundary (SI Figure S4). The Lower Eagle Ford has higher inferred total organic carbon (TOC) than the Upper Eagle Ford, with up to 10% TOC in some regions based on an analysis of geophysical logs.[15,16]

Previous analysis of the geology and production data identified four fluid regions in the Eagle Ford, two oil (black oil and volatile oil) and two gas (condensate and dry gas) zones that were used in this study[15,17] (SI Figure S5). The different zones were defined using gas to oil ratios (GORs). GORs were calculated from individual well production data in this study to delineate four "windows": an updip black oil window (GOR: 0−1500 ft^3/bbl) along the northern edge of the formation, transitioning downdip through a volatile oil window (GOR: 1500−10 000 ft^3/bbl), a wet gas condensate window (GOR: 10 000−100 000 ft^3/bbl), to a dry gas window (GOR: >100 000 ft^3/bbl).[17] The oil, volatile oil, and condensate windows were further subdivided into east and west regions with the exception of the dry gas zone which is mostly found in the west (Figure 1a, SI Figure S5, S6). Thermal maturation increases with burial depth from oil to dry gas (SI Figure S3). While the GOR indicates that there is a continuum between oil and dry gas, wells are generally classified either as oil wells or gas wells, based on the dominant product of the well, with the statutory definition of gas wells based on a GOR ≥100 000 ft^3/bbl. Analysis of data indicates that 99% of wells did not change class during the well lifetime. Liquids reported to be produced by a well classified as a gas well were assumed to be condensates.

Bakken Shale Play. The Bakken Play is located in western North Dakota and eastern Montana with production concentrated in a 13 500 mi^2 (35 000 km^2) area (Figure 1b, SI Figure S7). The term "Bakken" is used in this study to refer to production from both the Devonian/Mississippian Bakken Formation and the underlying Devonian Three Forks Formation (dolomitic mudstones). Most production from the Bakken Formation is from the middle member that consists of tight sandstones, siltstones, dolomite, and mudstone sandwiched between two shale members.[18] The Bakken is predominantly an oil field with <1% gas wells.[7]

Data Sources and Analyses. The approach used in this study includes five major steps: (1) collate data on HF water use from different databases and assess data reliability; (2) estimate HF water use per well and per unit length of lateral; (3) compare water use per well to oil or gas production per well; (4) compare water use for Eagle Ford with to that for the Bakken; and, (5) compare water use for unconventional oil production in the Eagle Ford and Bakken to water use for conventional oil production in the U.S. and Texas (SI Figure S8). We did not report on statistical significance of spatiotemporal differences in HF water use because all were significant because of large well populations whether differences were small or large.

State-based data on HF water use and liquid (oil or condensate), gas, and water production have been compiled from state records by commercial vendors, including IHS (www.ihs.com), used in this study. The FracFocus database was developed to compile information on chemical additives used in HF; however, the database also includes information on water volumes used in HF (www.FracFocus.org). Data from FracFocus can only be queried by individual well; however, other organizations such as PacWest and SkyTruth have compiled the data for all wells (pacwestcp.com, skytruth.org). Unlike the FracFocus database that only includes information on HF water volumes, the IHS database is more comprehensive, and includes information on well attributes (depth, length of laterals, etc.) and production (liquids [oil, condensate], gas, water). These additional data in IHS allow water use to be reported per unit length of lateral or per unit of energy production. Data were screened for errors by examining water use per well, water use per ft of lateral (gal/ft), total proppant use per well, and proppant loading (lb/gal). Data on HF water use were obtained from IHS and FracFocus and data on well characteristics (depth, length of laterals) were obtained from IHS database for 8301 wells in the Eagle Ford (2009–2013) and for 7868 wells in the Bakken (Figure 1a,b). Information on the HF fluid types for the Eagle Ford (i.e., slickwater, X-link gels, hybrid) was obtained from PacWest.[9,19]

To compare HF water use for oil and gas production, water use was reported for the different Eagle Ford production zones as defined by ranges of GOR values developed in previous studies (SI Figure S5).[15,17] The energy content of black oil is 5.8×10^6 Btu/Bbl (0.14×10^6 Btu/gal oil) and that of dry gas of 1×10^6 Btu/10^3 ft^3.[20] Therefore, 1×10^3 ft^3 of dry gas corresponds to 0.17 barrels of oil equivalent (BOE) or 7.24 gallons of oil equivalent (GOE) (42 gal/bbl). HF water to oil ratios (WORs, vol/vol, unitless) can be converted to gal water/10^6 Btu of energy by multiplying by 7.24 (7.24 gal oil/10^6 Btu). The metric equivalent of gal water/10^6 Btu is 3.59 L/Gigajoule. Liquid production (oil from oil wells and condensate from gas wells) and gas production (mostly dry gas from oil wells and wet gas from gas wells) are reported to the Texas Railroad Commission and are available in the IHS database. However, information on NGLs extracted from wet gas at gas processing plants is not reported and those volumes were estimated from previous studies for the Eagle Ford (6–8 gal/10^3 ft^3).[10] Estimated energy content of NGLs was then calculated based on quantities of different hydrocarbon (HC) products (C2–C4 lengths HCs) (SI, Section 4). Because HF water use occurs prior to oil or gas production, water use per unit of energy continues to decline with ongoing energy production throughout the lifetime of the well. The final HF water use per unit of energy depends on the estimated ultimate recovery (EUR) of the wells, which was evaluated from the literature.[17,18]

■ RESULTS AND DISCUSSION

Evaluation of Data Reliability. Data reliability was evaluated for the Eagle Ford data set (SI, Section 5). HF water use is available from IHS from the beginning of production in the Eagle Ford play (2009–2013) and from FracFocus (as aggregated by SkyTruth) from 2011–2013 (SI Table S1). Reporting to FracFocus became mandatory for Texas operators in February 2012; therefore, data prior to that time are based on voluntary reporting.

We found the rate of data reporting on HF water use in the Eagle Ford to be higher in FracFocus (94% of wells for 2013) than in IHS (74% of wells) (SI Table S1). However, IHS includes data for all wells completed, whether HF is reported or not. Therefore, average values of HF water use can be applied to wells without HF reporting. In contrast, there is no accounting for these wells in FracFocus and users depending solely on FracFocus may not be aware of this under reporting. For example, a recent report of HF water use based on FracFocus alone totaled 19.2×10^9 gal for 2011 through May 2013[7] as compared to 29.4×10^9 gal for 2011 through June 2013 based on combining IHS and FracFocus data. Analysis of the 2012–2013 data shows good agreement between the IHS and FracFocus databases, with 90% of the overlapping HF well population agreeing to within 10% on a well-by-well basis (SI Figure S9). Additional information on data validation is provided in SI, Section 5.

Overview of Water Use and Energy Production in the Eagle Ford. HF water use for the Eagle Ford Shale Play totaled 40×10^9 gal ($\sim 150 \times 10^9$ liters) for 8,301 wells (2009–2013); however, ~93% of the water use occurred from 2011 through 2013 (SI Table S2). HF water use in 2013 totaled 17.8×10^9 gal for 3,512 wells. Mean well depth averages ~2 miles (~10 000 ft) and mean length of horizontals or laterals is ~1 mile (~5 100 ft) (SI, Section 6, Figures S10, S11, Table S2). Interwell variability is high with depths ranging from 6,700–13,200 ft (5th –95th percentiles) and lengths ranging form 3,400–7,200 ft. (SI Table S3). There are ~100 operators in the Eagle Ford, with the top six operators representing ~50% of HF wells (SI Table S4). Production totaled 19.2×10^9 gal of oil, 7.3×10^9 gal of condensate, and 2.9×10^{12} ft^3 of dry gas (21.1×10^9 gal oil equivalent (GOE) (SI Table S2). Oil production increased by a factor of 5.6 between 2011 and 2013 with a corresponding approximate doubling of the number of oil wells completed annually.

A total of 79% of the wells are in the oil zones (44% in black oil zone (oil) and 35% in volatile oil-condensate (VOC) zone), while 15% of wells are in the condensate (C) zone and 6% are in the dry gas (DG) zone (SI Table S5). Wells in the black oil zone include 99.7% oil wells, those in the condensate zone include 97% gas wells and 3% oil wells, and those in the dry gas zone 99.4% gas wells; however, the volatile oil-condensate zone includes a mixture of 58% oil wells and 42% gas wells.

Comparison of Water Use for Hydraulic Fracturing in the Oil Zone relative to Condensate and Gas Zones in the Eagle Ford. HF water use (2009–2013) on a per well basis in the Eagle Ford oil and VOC zones (mean 4.8×10^6 gal/well) is similar to that in the condensate zone (4.7×10^6 gal/well) and dry gas zone (4.9×10^6 gal/well) (Table 1 and SI Table S6, Figure 2a and SI Figure S12). However, variability within each zone for water use among wells is high (e.g., 5th–95th percentile range of $2.3–9.0 \times 10^6$ gal/well in the black oil zone) (SI Table S7). Water use per unit length of lateral in the black oil and VOC zones (930–960 gal/ft of lateral) is similar to that in the condensate and dry gas zones (940–1020 gal/ft) (Table 1, Figure 1a and SI Tables S6, S13b) because the average length of laterals varies ≤4% of 5000 ft among zones. However, variability in water use/unit length of lateral is also high among wells within each production zone (SI Table S7).

Water use per unit of energy produced to date is ~2 times higher in the black oil zone in the Eagle Ford than in the dry gas zone because of lower energy production per well to date in the oil zone relative to that in the dry gas zone (Table 1). Because of close similarity in mean HF water use per well and per unit length of lateral across different production zones, variations in water use/unit of energy primarily reflect variations in energy production among zones. Water use per unit of energy is most readily calculated for either oil or dry gas

Table 1. HF Water Use in the Eagle Ford and Bakken Plays[a]

zone	HF 10^6gal/well	HF gal/ft	Prod OE 10^6gal/well	HF/OE ratio	EUR OE 10^6gal/well	HF/EUR ratio
Eagle Ford (2009–2013)						
O (oil)	4.82	927	3.40	1.42	13.4	0.36
O (all)	4.82	927	4.00	1.21	23.9	0.20
VOC (oil)	4.87	964	2.52	1.93	13.4	0.36
VOC (all)	4.87	964	6.92	0.70	28.6	0.17
C	4.70	940	9.46	0.50	35.3	0.13
DG	4.92	1,016	8.57	0.57	23.5	0.21
total play	4.83	947	6.11	0.79	28.1	0.17
Bakken (2005–2013)						
CB	3.08	319	3.85	0.80	8.2	0.38
ET	1.69	210	6.50	0.26	11.0	0.15
ECBN	0.82	98	5.07	0.18	5.2	0.16
NLK	1.84	200	4.72	0.39	10.2	0.18
NWT	1.89	236	1.78	1.06	3.3	0.57
total play	2.01	224	4.84	0.42	9.2	0.22

[a]More detailed information including number of wells is in SI Table S6. The ratios of HF water use to oil or oil equivalents (for VOC, C, and DG zones) based on production to date or to estimated ultimate recovery (EUR) of oil or gas are in terms of volume (gal of HF water/gal of oil equivalent) and can be converted to gal/Btu by multiplying by 7.24. EUR values for the different zones were estimated from ref 17. Estimates of water use for the oil zone are reported for oil production only (Oil) or for oil and associated gas (All) and for the VOC zone for oil wells only (Oil) and oil and gas wells (All). Drilling and cementing water use averages 0.38 gal water/well for the Eagle Ford and 0.24 gal water/well for the Bakken. HF water use totaled 40 × 10^9 gal from 8,301 wells in the Eagle Ford (2009–2013) and 16 × 10^9 gal from 7,868 wells in the Bakken (2005–2013). Eagle Ford: O: Oil, VOC: Volatile Oil-Condensate, C: Condensate, DG: Dry Gas production zones, as shown on Figure 1a. Bakken: CB: Central Basin, ET: Eastern Transitional, ECBN: Elm Coulee-Billings Nose, NLK: Nesson-Little Knife, NWT: Northwest Transitional, as shown on Figure 1b.

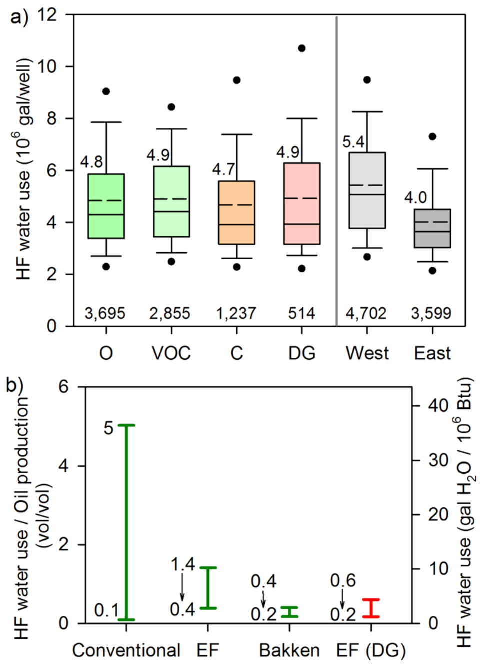

Figure 2. (a) Boxplot of HF water use in the Eagle Ford by production zone and averaged across zones in the west and east regions. Mean HF water use values are shown next to the boxes and the numbers of wells in each zone are shown along the bottom *X*-axis. Boxplots represent the mean (dashed lines in boxes), median (solid lines in boxes), 25th and 75th percentiles (bottoms and tops of boxes, respectively), and the fifth and 95th percentiles (bottom and top points, respectively). These values are also given in SI Table S6. (b) Comparison of water use for conventional oil production (vertical green line) with water use (drilling and hydraulic fracturing) for unconventional oil production in the Eagle Ford (EF) and Bakken plays (green points) and for dry gas (DG) production in the Eagle Ford (red points). Values shown in plot area represent the water-to-oil ratio (WOR) for oil or the water-to-oil equivalent ratio (WOER) for dry gas. Water use for conventional oil production generally ranges from 0.5 L to 5 gal water/gal oil. The upper point symbols represent water use relative to oil production to date (2009–2013 for Eagle Ford and 2005–2013 for Bakken), whereas the lower symbols and values represent water use relative to EUR values (Table 1).

zones because it can be estimated from reported values of oil and gas production. Cumulative HF water use generally tracks with oil and gas production in these zones (SI Figure S14).

In the black oil zone, the average HF water use of 4.8 × 10^6 gal/well relative to oil production to date (3.4 × 10^6 gal oil/well) results in a water-to-oil ratio (WOR) of 1.4 (vol/vol, v/v) (multiplied by 7.24 to convert WOR to 10 gal water/10^6 Btu; Table 1). In the dry gas zone, the ratio of HF water use per well (4.9 × 10^6 gal/well) to gas produced (8.6 × 10^6 GOE/well) results in a water-to-oil equivalent ratio (WOER) of 0.6 (equivalent to 4.1 gal water/10^6 Btu). These estimates of water use per unit of energy are based on production to date; however, these wells will continue producing for at least 20 years. Estimated ultimate recovery (EUR) for the black oil zone is 13.4 × 10^6 gal oil/well[17] resulting in a WOR 0.36 (2.6 gal/10^6 Btu). The corresponding estimate for the dry gas zone based on gas well EUR of 24 × 10^6 GOE/well)[17] is a WOER of 0.21 (1.5 gal water/10^6 Btu). Although water use per unit of energy is higher in the oil zone than in the dry gas zone, the 4–6 times higher price of oil than gas per Btu makes water use for oil more economically valuable.

Production in the VOC zone includes an estimated 34% oil, 19% condensate, 28% dry gas, and 19% NGLs. Details of converting production to units of energy are provided in SI, Section 4. The average per well HF water use and oil production in the VOC zone, considering only the oil wells in the VOC zone, results in similar ratios to those in the black oil zone; WOR of 1.9 based on production to date and WOR of 0.36 at EUR (Table 1). Considering all of the energy products in the VOC zone results in a WOR 0.70 for production to date and 0.17 at EUR. These values are similar to those estimated for the condensate (WOER: 0.5) and dry gas (WOER: 0.6) zones (Table 1). The similarity in water use per unit of energy for the VOC, C, and DG zones reflects the similarities in energy production in these zones, which is higher than that in the black oil zone by a factor of ∼2–3 (Table 1).

Spatial and Temporal Variability in Water Use for Hydraulic Fracturing in the Eagle Ford Play. While HF water use per well is similar among production zones (Oil, VOC, C, and DG zones), HF water use per well varies spatially within production zones, 26–40% higher in the west relative to the east in each production zone across the Eagle Ford play (Figure 1a, SI Table S8). For example, HF water use is 34% higher in the oil zone in the west (5.6 × 10^6 gal/well) than in the east (4.1 × 10^6 gal/well) (SI Figure S12, Table S8). Although we cannot fully account for higher HF water use in the west relative to the east, many factors may contribute to this spatial variation in higher water use:

- 10% longer average laterals in the west relative to the east; however, this does not fully explain the difference as mean water use per unit length of lateral is 22% higher in the west than in the east (SI Figure S11, Table S8).
- The number of frac stages cannot explain the differences in water use with a median of 15–17 frac stages in both the east and west production zones, resulting in similar median stage lengths varying from 280–330 ft (SI Table S9).
- Differences in HF fluid types (SI Section 7).[5] The dominant HF fluid types in the Eagle Ford include hybrid X-link gels-slickwater (XL-SW, 66%), X-link gels (XL, 20%) and slickwater (10%) with minor amounts of hybrid linear gels-slickwater (LG-SW, 4%) and <1% linear gels (LG) (SI Tables S10, S11). SW or LG-SW hybrid fracs use 55–110% more water than XL fracs, including XL and XL-SW fracs (SI Table S11). The more water intensive slickwater gels have only been used in the west; however, they also only represent 17% of the wells drilled in the west. HF water use in wells that used the same fluid types are ≤20% higher in the west relative to the east, indicating that other factors are also affecting spatial variability in water use (SI Table S11).
- Overpressuring of wells in the east (0.5–0.8 psi/ft) relative to those in the west (< ∼ 0.4–0.65 psi/ft), which might reduce HF water requirements (SI, Section 8, Figure S15). Differences in pressure gradients may be related to geologic history associated with uplift or exhumation of the Eagle Ford sediments in the west by 3000–7000 ft whereas Eagle Ford sediments in the east are found at their original burial depths.[19]
- Differences in geology with the upper Eagle Ford restricted to the west subregion (12) (SI Figure S4); however, the primary target for oil and gas is the lower Eagle Ford which extends throughout the play.

Understanding temporal variability in HF water use in the Eagle Ford is limited by the short production record with 94% of wells drilled from 2011–2013 (SI Table S2). In each of the production zones there was generally decreasing HF water use/well and per unit length of lateral during 2009–2011; however, the number of wells drilled was generally low (<10% of total wells) during this time (SI Figures S16–S19). These early reductions in water use may have resulted from switching fluid types from slickwater to x-link gels. Mean annual HF water use per well and per foot of lateral generally stabilized in 2011, varying < ∼10% from 2011–2013. Proppant loading generally increased over time until early 2012 and may reflect changes in HF fluid types.

Drilling, Cementing, and Proppant Water Use. In addition to water requirements for HF, water use for drilling and cementing wells is not reported but was estimated to average 0.38×10^6 gal/well (∼8% of mean HF water use), representing six times mean well bore volume (i.e., $6 \times 0.06 \times 10^6$ gal) for drilling water to match reported values for a limited number of wells, and an additional $\sim 0.02 \times 10^6$ gal/well for cementing (SI, Section 9, Table S12). The estimates for drilling water may overestimate water use by other operators who report using oil based muds rather than water for drilling the lateral sections of wells. In addition, indirect water use for proppant production is estimated to average 0.7×10^6 gal/well (∼15% of mean HF water use) (SI Table S12). However, proppant production does not impact local water sources as it is mostly transported from central Texas or Wisconsin (SI Figures S20–S21). Thus, the resultant additional water use for drilling/cementing and proppant production is $\sim 1.1 \times 10^6$ gal/well, increasing the estimated average water use per well by ∼20%.

Comparison with Hydraulic Fracturing Water Use in the Bakken. Unlike the Eagle Ford Play which includes oil, condensate, and gas zones, the Bakken is predominantly an oil play with <1% gas wells. About 18% (1,403) of the wells in the Bakken have multiple laterals from a single vertical, with mostly 2 (1,040 wells) or 3 (291 wells) up to a maximum of 8 laterals. Total HF water use in the Bakken is 15.8×10^9 gal for 7868 wells (2005–2013) (SI Table S13), which is less than half of that for the Eagle Ford (40×10^9 gal from 8301 wells, 2009–2013) (Table S2). HF water use for 2013 averaged 2.8×10^6 gal/well in the Bakken, about half of that in the Eagle Ford although laterals average almost two times longer in the Bakken (9,450 ft) than in the Eagle Ford resulting in water use per foot of lateral in the Bakken (300 gal water/ft) (SI Table S13) being about a third of that in the Eagle Ford (Table SI, Table S2). Oil production (2005–2013) in the Bakken averaged 4.8×10^6 gal oil/well for the play, ∼1.4 times greater than that in the Eagle Ford black oil zone (3.4×10^6 gal oil/well) (Table 1). Although variability in water use is large within the Eagle Ford and Bakken plays, the distribution of HF water use is distinctly different between the two plays (SI Figure S22). Considering the average HF water use/well in the Bakken (2005–2013, 2.0×10^6 gal/well, SI Figure S23) relative to oil production to date (4.8×10^6 gal oil/well) results in a WOR of 0.42 (3.0 gal water/10^6 Btu) which is about a third of that in the Eagle Ford (Table 1 and SI Table S6). The estimated weighted EUR of 9.2 $\times 10^6$ gal oil/well across the Bakken[18] results in a WOR of 0.22 over the life of the wells.

Differences in water use between the Bakken and Eagle Ford are not attributed to variations in HF fluid types, because these are similar in the two plays, mostly XL gels and hybrid XL/SW gels.[19] The median number of frac stages per well in the Bakken is almost double that in the Eagle Ford, consistent with the ∼2 times longer laterals in the Bakken wells (SI Table S9). The differences in HF water use may reflect differences in geology with most of the Bakken production from tight sandstones, siltstones and dolomitic mudstones in the Middle Member sandwiched between shales rather than shales in the Eagle Ford.[18] Although HF water use for wells in the Bakken is low, the N. Dakota Department of Mineral Resources reports that additional water, termed "maintenance water", is added to the wells to reduce salinity build up because of the high salinity of the produced water.[21] Chloride concentrations in produced water ranges from 2700 to 311 000 mg/L (mean 137 000 mg/L), with 98% of analyses >50 000 mg/L, based on 295 samples from Bakken production wells sampled between 2005 and 2013, and tabulated in the USGS Produced Waters database (www.energy.usgs.gov). Discussions with operators indicate that not all wells require maintenance water and the volume varies with estimates from 0–700 gal/day, which would result in up to 5×10^6 gal/well, assuming a 20 yr lifetime for wells.[22]

Temporal variability in HF water use in the Bakken is characterized by almost an order of magnitude increase in HF water use from 0.31×10^6 gal/well in 2005 to 2.8×10^6 gal/well in 2013 (SI Figure S23, Table S13). This increase is partly related to variation in average lateral length, which increased from ∼7200 ft in 2005 to 9500 ft in 2013, resulting in a respective increase in normalized water use of 43 gal/ft to 295 gal/ft of lateral. Proppant loading per gal of water has generally decreased over time from 2.5 to 1.2 lbs/gal (SI Figure S23). Estimates of water use for drilling averaged 0.23×10^6 gal/well (SI Table S14).

Comparison of Water Use for Unconventional versus Conventional Oil Production. Water use for HF for oil production has an average WOR of 1.4 in the Eagle Ford and 0.42 in the Bakken, based on production to date (Table 1). These ratios are within the lower range of reported freshwater use for conventional oil production in the U.S. (WOR: 0.1–5).[11,18] Use of EURs rather than production to date results in lower water intensities with WOR of 0.36 for the Eagle Ford and 0.22 for the Bakken.

The estimated total water requirements, including fresh and nonfresh water, for conventional oil production in the U.S. weighted according to production by primary, secondary, and tertiary recovery in 2005 has a WOR of 8 (SI, Section 10).[13] Total water use for primary recovery is minimal, limited to well drilling (WOR: ~0.2), but is higher for secondary recovery (including water flooding; WOR: ~8.6 over the lifespan of the well[23]), and has a large range for tertiary recovery (enhanced oil recovery using steam or CO_2, WOR: ~1.9–13[23]). Data on water use for conventional oil production are limited, with estimates for secondary recovery restricted to a single study.[22] An estimated 80% of the total water required for conventional oil production is attributed to secondary recovery, which accounted for ~70% of onshore U.S. oil production in 2005.[13] However, the important issue is what percent of the water use is fresh water versus water that is coproduced with oil (produced water). The volume of water produced in conventional oil wells averages ~7 times that of oil produced on a national basis and ~70% of this produced water is reinjected for oil production (70% of 7 gal = 5 gal produced water). Therefore, subtracting the produced water use (5 gal) from the total water requirement for conventional oil production (8.6 gal) results in an average volume of nonproduced water or net water to oil ratio (WOR) of 3.6 in conventional wells, ranging from WORs of 2.3 in south central US to 5.4 in western U.S. (11). A detailed analysis of fresh water use for conventional oil production in California from 1999–2012 results in WORs of ~2–3.[24]

Reported water to oil ratios (WORs) for conventional production in Texas, using surveyed data from 1995, is 0.5.[25] A total of 1,543 surveys were mailed to operators throughout Texas in 1995 with an 84% response rate.[26] Survey results indicated that 11×10^9 gal of fresh water and 3×10^9 gal of produced water were used for oil production, mostly for water flooding to enhance secondary production. However, the Texas Railroad Commission defines freshwater as water with Total Dissolved Solids (TDS) from 0–3000 mg/L), as compared to the definition for municipal drinking water, which is ≤1000 mg/L TDS. A new survey of operators in the Permian Basin in Texas in 2010, where most water flooding takes place, suggested that the percentage of freshwater used in the Permian Basin in Texas decreased from 75% of water used in 1995 to 20% in 2010, reducing the WOR to 0.1.[25] The estimates of water use for HF in the Eagle Ford and Bakken plays based on production to date (WOR: 0.42–1.4) or on EUR (WOR: 0.22–0.36) generally fall within the lower range of WORs for conventional production (WOR: 0.1–5). Therefore, increased water use in recent years is attributed to expanded oil production using HF and not because HF is more water intensive per unit of oil production.

■ IMPLICATIONS

The results of this study have important implications for water demand for HF relative to oil production. Data for the Eagle Ford Shale indicate that HF water does not vary for shale oil versus shale gas wells on a per well or per unit lateral length; therefore, variations in HF water use per unit of energy depend on the energy production in oil versus gas wells. HF water use can vary markedly between plays, such as in oil zones in the Eagle Ford relative to the oil rich Bakken play. Evaluation of various operational factors that can contribute to differences in HF water use (e.g., length of laterals, HF fluid types, frac stages etc.) suggests that the dominant factor may be production from tight formations in the Bakken with lower HF water demands relative to production from shales in the Eagle Ford.

Although the public perception is that there are huge water demands for HF, results from this study indicate that HF water use to oil production ratios (WORs) for unconventional oil production are within the lower range of those for conventional oil production, considering the well lifetime. Therefore, increased water use for HF is related to increased energy production as shown by the tracking of HF water use with unconventional energy production in plays. The detailed evaluation of HF water use in this study for the top two oil plays in the U.S. can provide valuable input to studies assessing impacts of shale oil and gas development on water resources and can also be used in future economic and policy studies about environmental impacts of unconventional energy production.

■ ASSOCIATED CONTENT

Supporting Information

Additional information is provided in Supporting Information on various topics, including evaluation of energy content, HF water use database comparisons, estimation of well depths and length of laterals, estimation of well pressure gradients, data on HF fluid types and related water use, water use for borehole drilling, and water use for conventional production. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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SELECTED LIST OF ACRONYMS AND UNITS:

GOE gallon of oil equivalent to volume of gas
HF hydraulic fracturing
1 gallon (gal) 3.785 L (L)
1 barrel (bbl) 42 gal
1 bbl of oil 5.8×10^6 Btu
1 gal of oil 0.14×10^6 Btu
1×10^3 ft^3 gas 1×10^6 Btu
1×10^6 British thermal unit (Btu) 1.055×10^9 Joules =1.055 Gigajoules
1×10^6 Btu = 7.24 gal of oil 0.17 bbl of oil
1×10^3 ft^3 of gas (1 mcf) 0.17 bbl oil equivalent (BOE, 1×10^3 ft^3 gas $\times$ 1×10^6 Btu/10^3 ft^3 gas $\times$ 1 bbl oil/5.8×10^6 Btu)
1 gal/10^6 Btu 3.79 L/Gigajoule
water-to-oil ratio (WOR, HF water used to oil produced) (vol/vol, unitless) is equivalent to 7.24 gal water/10^6 Btu
water-to-oil-equivalent ratio (WOER, HF water used to equivalent volume of oil produced, unitless)

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