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Water Use for Shale-Gas Production in Texas, U.S.

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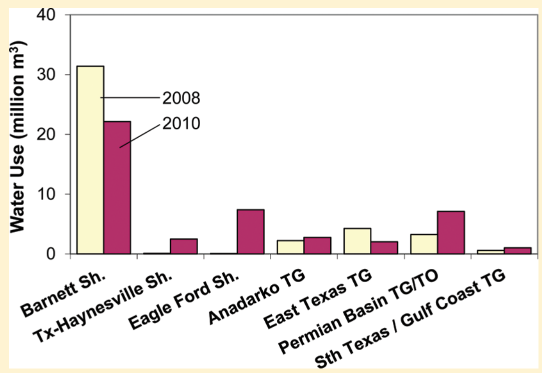
S Supporting Information

ABSTRACT: Shale-gas production using hydraulic fracturing of mostly horizontal wells has led to considerable controversy over water-resource and environmental impacts. The study objective was to quantify net water use for shale-gas production using data from Texas, which is the dominant producer of shale gas in the U.S. with a focus on three major plays: the Barnett Shale (~15 000 wells, mid-2011), Texas-Haynesville Shale (390 wells), and Eagle Ford Shale (1040 wells). Past water use was estimated from well-completion data, and future water use was extrapolated from past water use constrained by shale-gas resources. Cumulative water use in the Barnett totaled 145 Mm^3 (2000−mid-2011). Annual water use represents ~9% of water use in Dallas (population 1.3 million). Water use in younger (2008−mid-2011) plays, although less (6.5 Mm^3 Texas-Haynesville, 18 Mm^3 Eagle Ford), is increasing rapidly. Water use for shale gas is <1% of statewide water withdrawals; however, local impacts vary with water availability and competing demands. Projections of cumulative net water use during the next 50 years in all shale plays total ~4350 Mm^3, peaking at 145 Mm^3 in the mid-2020s and decreasing to 23 Mm^3 in 2060. Current freshwater use may shift to brackish water to reduce competition with other users.



INTRODUCTION

Natural gas has spurred intense interest in reducing greenhouse gases and enhancing energy security. Natural gas produces emissions that are much lower than those from oil and coal: 30%−40% lower for CO_2, 80% for NO, and ~100% for SO_2, particulates, and mercury.[1] Natural gas is used widely for industrial (31%), electric power (27%), residential (22%), commercial (14%), and other purposes (mean 2000−2010).[2] Production of natural gas from hydrocarbon-rich shales is referred to as shale gas. Shales contain gas in micropores, fractures, and adsorbed onto organic matter. Conventional gas has been produced from permeable geologic formations for decades; however, within the past decade, advances in directional drilling, combined with breakthroughs in fracking in Texas, have allowed large-scale expansion of gas production from low-permeability shale formations at depths of >1 km. Shale-gas reservoirs differ from typical oil and gas reservoirs in that the shale serves as the source rock, reservoir, and seal. Although older wells in older plays, such as the Barnett, and exploratory wells in newer plays are vertical (Supporting Information, A), most wells are currently drilled vertically almost to the depth of the shale formation, then deviated to the horizontal and drilled horizontally within the shale. Fracking involves injection of water containing chemical additives and proppant (e.g., sand) under high pressure to fracture the shales.[3] Early expansion of shale-gas production was restricted primarily to the Barnett Shale in Texas, which was the main producer in the 2000s, accounting for 66% of shale-gas production in the U.S. in 2007−2009;[2] however, shale gas is currently produced in 22 of the 50 states, and production increased by an annual average rate of ~50% between 2006 and 2010.[4] Shale-gas production is projected to increase from 23% of U.S. natural gas production in 2009 to 47% by 2035.

Energy and water production are interdependent. In the shale-gas context, there is a strong correlation between water injected and gas production (Supporting Information, B). Most studies of water-resource impacts from shale-gas exploration and production have focused on effects of fracking on water quality;[5] however, some studies also emphasize impacts on water quantity.[6−10] Few published studies quantify water use for shale-gas production and their environmental impact.[11−13] Water use for hydraulically fracturing wells varies with the shale-gas play, the operator, well depth, number of fracking stages, and length of laterals. To date, generally fresh water (total dissolved solids <1000 mg/L) has been used for fracking, sourced from surface water or groundwater, depending on local availability. The commonly used polyacrylamide additives (friction reducers) function best in fresh water.[14]

Impacts of water production for shale-gas development depend on water availability in the region and competing demands for water from other users. Limited water availability in semiarid regions may restrict shale-gas production. Impacts range from declining water levels at the regional[10−12] or local[6]

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scales and related decreases in base flow to streams. Although shale-gas production is currently mostly limited to North America, large reserves have been estimated in other regions globally, and water availability may be more problematic in some of these regions, such as northwest China and South Africa, where water scarcity is already a problem.[15,16]

The objective of this study was to quantify net water use (water consumption) for shale-gas production using the major shale-gas plays in Texas as examples (Barnett, Haynesville, and Eagle Ford shales) (Figure 1) and focusing on the single best-estimate scenario. Overall fracking activities in Texas show little difference between water use and net water use. Texas has the longest history of shale-gas production, and impacts on water quantity should serve as a guide for production in younger plays in the U.S. and globally. Experience from Texas shale-gas plays provides insights into water-quantity requirements and water-use.

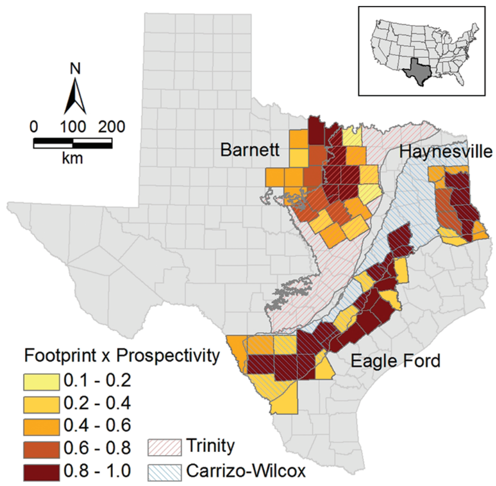

Figure 1. Location of major shale-gas plays in Texas. Colors represent the product of fraction of county area within play footprint (number >0 and ≤1) and prospectivity (number >0 and ≤1). Core counties in the Barnett include Denton, Johnson, Tarrant, and Wise. Core counties in the Haynesville include Harrison, Panola, Shelby, and San Augustine. Counties of interest in the Eagle Ford are Dimmit, De Witt, Karnes, La Salle, Live Oak, and Webb. Outlines of the Trinity and Carrizo Wilcox aquifers are also shown.

■ MATERIALS AND METHODS

Shale-Gas Plays in Texas. The Barnett Shale has been producing gas since the early 1990s and is the formation in which horizontal drilling and fracking were pioneered (Figure 1). Productive Mississippian Barnett Shale is found at depths of 2.0−2.6 km near the Dallas−Fort Worth metroplex, with shale thickness varying from 30 to 180 m. The play, which includes a core area of four counties (7800 km^2 area), extends to all or parts of 26 counties (~30 000 km^2). The Haynesville Shale extends from Louisiana into Texas, with ~35% of the play in Texas (Tx-Haynesville). Production in the Upper Jurassic Haynesville Shale began in 2008. Haynesville Shale thickness ranges 60−90 m at 3−4 km depth. The play area is ~11 500 km^2 in Texas (10 counties), with a core area of 7500 km^2 (four counties). The discovery well for the Eagle Ford Shale was drilled in 2008. The average shale thickness is 75 m, and it is found at depths of 1.2−3.4 km. The play area extends over ~24 counties (~50 000 km^2). Some shale plays contain only gas (e.g., the Haynesville), whereas others contain both oil and gas, either at the same location in a so-called combo play (e.g., north section of Barnett) or in spatially distinct zones with oil at shallower depths (e.g., Eagle Ford).

Estimation of Past Water Use for Shale-Gas Production. Water use for shale-gas production in Texas can be readily estimated because operators are required to report water used for completion, including fracking, to the Railroad Commission (RRC) of Texas (forms G-1 and W-2). Unfortunately, because information on source or quality of water is also not required, water use estimates may include a small proportion of slightly brackish water (total dissolved solids <5000 mg/L). Surface water in Texas is owned and managed by the State and requires a water-right permit for diversions. Groundwater is owned mostly by landowners but is generally managed by legislatively authorized groundwater conservation districts (GCDs); nevertheless, groundwater withdrawal for oil and gas exploratory activities, including fracking, is exempt from GCD regulations under the State water code.[10]

Information on water use for fracking for shale-gas production was obtained indirectly from the RRC through a vendor (IHS) database. Water use was either provided in the database or estimated from proppant loading (proppant mass divided by water volume), when available, or from water-use intensity (water use divided by length of vertical or lateral productive interval) for each well. The reliability of water use estimates was evaluated by comparing estimates from different approaches. If discrepancies among various water-use estimates could not be resolved for a particular well, water use was assigned a mean water use in the play (Supporting Information, C). Additional information, such as surface water or groundwater source, was obtained directly from facilities/operators responsible for water use. Wells with water use ≤380 m^3 (0.1 million gallons, Mgal) were omitted from analysis to distinguish simple well stimulation by traditional fracking and acid jobs from the now common high-volume fracking jobs (Supporting Information, C). Data on water use for drilling, rather than fracking, are much more difficult to obtain because operators are not required to report this water use.

Estimation of Future Water Use for Shale-Gas Production. Future water use for shale-gas production was estimated for 2010−2060 based on extrapolation of current trends and performed at the county level (500−8800 km^2 areas) by (1) estimating spatial area of the shale-gas play and most likely spacing between laterals, (2) estimating water-use intensity from historical data, and (3) computing total water use. Estimating spatial well coverage density is an important step. Horizontal well laterals are mostly parallel and oriented approximately perpendicular to minimum local horizontal stress. Distance between laterals ranges approximately from 250 m for oil wells to 300 m for all other wells according to field evidence and discussion with operators. The next steps consisted of (4) adjusting water use for spatial distribution within a county and (5) distributing water use through time. Spatial distribution is controlled by a county-level prospectivity factor (0.3−1.0), which includes assessment of shale depth, thickness, maturity (amount and type of organic matter in shale, thermal maturity, burial history, microporosity, and fracture spacing and orientation), and location relative to core area (Supporting Information, F). The role of the prospectivity factor is to include these variables to the best of our knowledge in the projections. Consequently, this county-level assignment

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was done on the basis of educated estimates relative to industry projections resulting from discussions with expert geologists.

Temporal distribution of total water use at the county-level was based on assumptions about individual gas-well performance, projections on rig availability, prospectivity, and progress in recycling and reuse. Individual gas-well performance is characterized by initial production (IP), decline curve (how rapidly wells decline from the IP), and cumulative potential (estimated ultimate recovery, EUR). A limiting factor that controls the number of wells drilled each year is the number of available drilling rigs. A lower prospectivity translates into a delayed start date relative to more prospective counties. Recycling and reuse are a strong function of amount of injected water returning to the surface, which is always a relatively small fraction of amount injected.[13] Projections assume a slow annual increase in recycling and reuse up to 20% of total water use in 2060 for the Barnett and Eagle Ford shales (only 3% for Haynesville Shale) to yield the net water use[13] (Supporting Information, E). Refracking can also impact water-use projections. This study assumes that all possible restimulations have already been done and that newer wells will not be restimulated (Supporting Information, H). Earlier projections, following a procedure similar to that presented in this section, but restricted to the Barnett Shale, still hold, increasing confidence in the approach (Figure 2).[12] They also

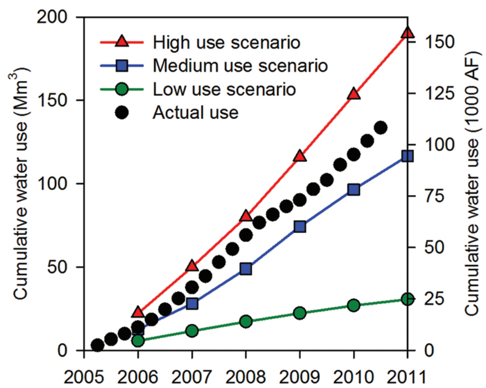

Figure 2. Postaudit analysis of water-use projections (solid lines) made in 2006[12] relative to actual water use (dots) through mid-2011 for the Barnett Shale (cumulative as of June 2011) (tick marks = completed year, so 2011 is 12/31/2011). This figure gives an estimate of the uncertainty associated with the analysis, which provides cumulative water use projections within less than a factor of 2 in the next 5−10 years. The assumption that current trends will still be valid beyond the 10-year horizon becomes weaker with increased uncertainty in the projections. Postaudits of long-term projections show that they often deviate from estimates because of unpredicted events, with unprecedented water-intensive shale-gas production being an example.

suggest that projections of cumulative water use at the play level are valid within a factor of less than 2 at a 5−10-year horizon with increased uncertainty beyond the decade or when the area of interest decreases from shale play to county.

RESULTS AND DISCUSSION

Past Water Use for Shale-Gas Production. Shale-gas production in the U.S. was dominated by production in the Barnett Shale during the past decade, which increased from 0.3 Gm^3 (2000) to 52 Gm^3 (2010) (10−1840 billion cubic feet).[17] Past water use for fracking totaled 145 Mm^3 (117 thousand acre-feet, kAF; 1 AF = 325 851 gal) to June 2011 (Table 1) to

Table 1. Statistics for Major Shale-Gas Plays in Texas[a]

formation	area (km^2)	use (Mm^3)	wells	WUW (m^3)	WUI (m^3/m)	proj (Mm^3)
Barnett	48 000	145	14 900	10 600	12.5	1050
TX-Haynesville	19 000	6.5	390	21 500	14.0	525
Eagle Ford	53 000	18	1040	16 100	9.5	1870
other shales						889
tight formations						895

[a]Area: total area. Use: cumulative water use to 6/2011. Wells: number of wells to 6/2011. WUW: median water use per horizontal well during the 2009−6/2011 period; WUI: median water-use intensity for horizontal wells during the 2009−6/2011 period; Proj: projected additional total net water use by 2060. "Other shales" are mostly located in West Texas, whereas tight formations occur across the state. Note: The same table is reproduced in English units in the Supporting Information.

stimulate ∼15 000 wells. Fracking water use in the Barnett in 2010 represented ∼9% of the 308 Mm^3 (250 kAF or ∼80 000 Mgal) used by the City of Dallas,[18] the ninth-largest city in the U.S. (population 1.3 million 2010). Wells were predominantly vertical until 2005 (∼450−600 wells/yr in 2000−2005) when the number of horizontal wells drilled exceeded the number of vertical wells and reached a maximum of ∼2500 in 2008 (Figure 3). Water use for horizontal wells in 2010 ranged

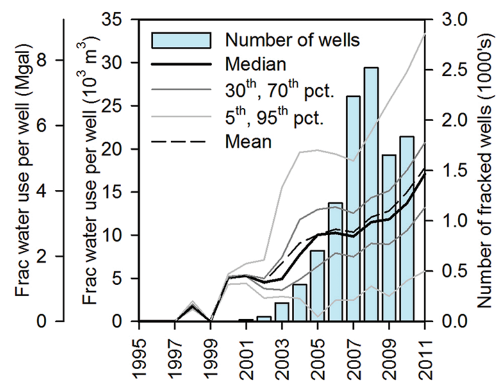

Figure 3. Time evolution of Barnett Shale well count and water use per well percentiles.

2900−20 700 m^3/well (5th−95th percentiles; 0.75−5.5 Mgal), with a median of 10 600 m^3/well (2.8 Mgal) (Supporting Information, D). Water-use percentiles systematically increased during the past decade, as lateral lengths and number of fracking stages increased (Figure 3). Variations in water use among wells result from differences in length of laterals and in water-use intensity (median for horizontal wells of 12.5 m^3/m−1000 gal/ft). Median water use for vertical wells is 4500 m^3 (1.2 Mgal). Water use is reported for most (97% in 2009−2010) Barnett Shale wells. Gas production and water use are concentrated in the core counties, accounting for ∼80% of the 31.4 Mm^3 (25.5 kAF) of total water consumed in 2008 (Table 2).

Approximately 1820 wells had been drilled in the entire Haynesville shale-gas play extending into Louisiana by mid-2011, with a total water use of 36 Mm^3 (29.5 kAF), including 390 wells and 6.5 Mm^3 (5.3 kAF) in Texas (Table 1). Currently, most wells are horizontal. Median water use for horizontal wells in the entire Haynesville play in 2010 was 21

Table 2. County-Level 2008 Total and Fracking Water Use in Core Counties[a]

county			2008 net water use				projected net water use		
name	population	area (km^2)	total (Mm^3)[d]	GW (%)	SG (Mm^3)	SG (%)	max (Mm^3)[d]	max (%)	max year
Barnett									
Denton[b]	637 400	2460	120	13	3.4	2.8	2.1	1.7	2010
Johnson	155 200	1880	35	45	10.4	29	4.1	11	2010
Parker	111 600	2390	21	49	2.2	10	4.9	23	2010
Tarrant[b]	174 100	2320	453	5	6.3	1.4	3.9	0.9	2010
Wise	58 500	2400	14	42	2.7	19	5.7	40	2010
Eagle Ford									
De Witt	20 200	2350	8	86			2.8	35	2023
Dimmit	10 000	3460	12	88	0.0	0.1	6.7	55	2015
Karnes	15 300	1970	6	91			2.5	39	2018
La Salle	6000	3840	8	95	0.0	0.1	7.1	89	2019
Live Oak	12 100	2780	8	66			1.0	12	2024
Webb[c]	238 300	8790	56	3	0.0	0.0	2.9	5.2	2013
TX-Haynesville									
Harrison	64 200	2370	45	11	0.1	0.2	3.3	7.4	2017
Panola	23 300	2120	10	37	0.0	0.5	3.0	30	2017
San Augustine	9000	1530	3	30			4.1	136	2017
Shelby	26 200	2160	11	27			5.8	55	2017

[a]Name: county name. Population: estimated 2008 population. Area: county area. Total: total net water use. GW: estimated net groundwater use as a percentage of total net water use. SG: 2008 shale-gas net water use and percentage of 2008 total net water use. Max: projected maximum shale-gas annual net water use and percentage of 2008 total net water use. Max Year: calendar year of projected maximum. http://www.twdb.state.tx.us/wrpi/wus/2009est/2009County.xls. Note: The same table is reproduced in English units in the Supporting Information. [b]Includes City of Fort Worth and other communities relying primarily on imported surface water. [c]Includes City of Laredo. [d]Assumes that the water originates from the county in which it is used.

500 m^3 (5.7 Mgal), ranging from 2700 to 28 100 m^3 (5th and 95th percentiles; 0.7–7.4 Mgal). Water-use intensity is not as clearly defined as it was in the Barnett Shale because of the smaller sample size, but it is slightly higher (14 m^3/m; 1120 gal/ft) than that of the Barnett Shale.

Fracking for shale-gas production in the Eagle Ford Shale began in 2008. Wells drilled in the Eagle Ford Shale totaled 1040 with cumulative water use of 18 Mm^3 (14.6 kAF) by mid-2011 (Table 1). Water use per well ranged from 4600 to 33 900 m^3 (5th and 95th percentiles; 1.2–8.9 Mgal), with a median of 16 100 m^3/well (4.3 Mgal)). Water-use intensity ranged from 3.4 to 22.9 m^3/m (5th–95th percentile; 270–1850 gal/ft), with a median of 9.5 m^3/m (770 gal/ft), currently less than that for the other two plays. This median value quickly decreased from the earlier 15.5 m^3/m (1250 gal/ft) used in the projection section, and that included only 155 wells.[13] Counties with the largest water use are Dimmit, Webb, and La Salle (>50% of total), with six surrounding counties making up the balance, in particular, De Witt, Karnes, and Live Oak, where activity increased in 2011. All of these counties are located in the oil or wet-gas window of the play.

The source of water for fracking is not well documented in Texas. Fracking water in the Barnett Shale for 2005–2007 was estimated to be 60% from groundwater (range 45–100%, depending on the county), but the source varies with time.[11] East Texas, which has abundant surface water, also hosts large aquifers. Haynesville shale-gas production in Louisiana parishes bordering Texas initially relied heavily on local groundwater from the Carrizo aquifer but currently derives ~75% of water from surface water (Pers. comm., Gary Hanson, Louisiana State Univ., Shreveport) or lesser quality shallow groundwater.[19] Surface water in the Eagle Ford footprint is not as abundant as in the northeast sections of the state hosting the Barnett and Haynesville shales, and operators have relied mostly on groundwater from the Carrizo aquifer, except for use of Rio Grande water at the Mexican border.

Additional consumptive water uses related to shale-gas fracking include drilling and sand mining for proppant production, which amount to an additional ~25% water use relative to fracking water use proper[13] (Supporting Information, E). Recycling and reuse of fracking fluid was estimated to range from 5% to 10% for the Barnett Shale and ~0% for the Tx-Haynesville Shale (Supporting Information, E).

Although hydraulic-fracturing net water use in Texas, including other tight plays in West Texas (44.7 Mm^3, 36 kA, in 2008), is significantly higher than net water use for other oil and gas activities (total of 70.6 Mm^3 (57 kAF) in 2008, including fracking, drilling, and waterflooding, injection of water into an oil reservoir), oil and gas mining net water use did not dominate other mining net water uses in Texas (mining net water use total of 197 Mm^3, 160 kAF, in 2008). Aggregate mining, lignite-mine dewatering, and other minor uses represented approximately two-thirds of mining water use in 2008 (Supporting Information, I).[13] In the larger context of overall state water use, mining represented <1% of the total water use of 22 600 Mm^3 (18 300 kAF) in 2008, most of it consumptive.

Projected Water Use for Shale-Gas Development. Projections of gas production for the Barnett Shale are based on earlier projections,[12] supplemented by prospectivity updates for both gas and oil windows by Tian and Ayers.[20] Parameters used for the estimates include play area (48 000 km^2), spacing of laterals (300 m for gas and 250 m for oil), and water-use intensity of 12.5 m^3/m (1000 gal/ft), resulting in a total net water use of 1050 Mm^3 (853 kAF) in 2010–2060 (Table 1). Temporal variations in projected net water use are based on projected peak water production in 2017 at 60 Mm^3 (48 kAF), decreasing to ~0 in 2040 (Figure 4). Projections were

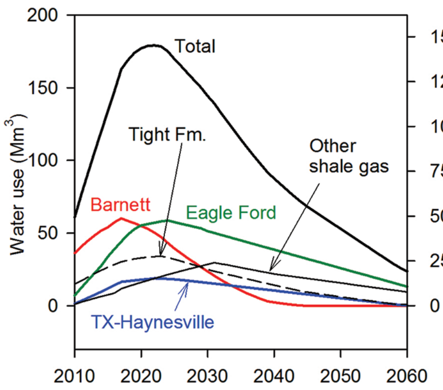

Figure 4. Time evolution in Texas of fracking net water use distributed among the Barnett, Tx-Haynesville, Eagle Ford, and other shale-gas plays to which water-use fracturing of more traditional tight formations is added.

distributed spatially by county according to their respective prospectivity. High water-use counties are outside of the core area, where it is assumed that drilling activity peaked in 2010.

Parameters required for estimating water use for the Tx-Haynesville Shale include play area (19 000 km^2), lateral spacing (300 m), and water-use intensity of 13.6 m^3/m (1100 gal/ft), resulting in a total projected net water use of 525 Mm^3 (425 kAF) peaking at 19.0 Mm^3 (15.4 kAF) in 2022 (Figure 4). Projected water-use estimates for the Eagle Ford play relied on the play area (53 000 km^2), lateral spacing (300 m for gas and 250 m for oil), and water-use intensity of 15.5 m^3/m (1250 gal/ft), resulting in a total net water use of 1870 Mm^3 (1515 kAF) (Table 1) peaking at 58 Mm^3 (48 kAF) in 2024 (Figure 4).

Projected net water use is lowest for the Tx-Haynesville and highest for the Eagle Ford shale-gas plays reflecting variations in gas reserves associated with play area. Projections for these plays are more uncertain than those of the Barnett Shale, because of their young age (2008). Recent information suggests that water-use intensity is decreasing, particularly in the Eagle Ford Shale. In addition, gas-production rates from limited drilling restricted to certain areas of the plays are assumed to represent future production rates over the entire play.

Projected water use is also contingent on gas price because drilling and completion activities are more sensitive to gas price than production. All gas plays, even those with marginal permeability, should be hydraulically fractured when gas prices exceed \$10 per thousand cubic feet (Mcf) (\$0.35/m^3), more so if the gas contains condensate, and development should be accelerated relative to that projected in this study. Conversely, if gas price remains below \$5/Mcf (\$0.18/m^3) for an extended time, water-use projections from this study may be too high. Given the current low gas price relative to that of oil in terms of energy content, more companies have become interested in condensate, whose price more closely follows that of oil and in oil-rich shale plays (northern confines of Barnett Shale, western edge of Eagle Ford Shale).

Overall annual net water use for fracking shale formations is projected to increase from the current 46 Mm^3 (37 kAF) to a peak of 145 Mm^3 (117 kAF) by 2020–2030.[13] If minor water use for tight formations (Supporting Information, I) is included, fracking annual net water use peaks at 179 Mm^3 (145 AF) (Figure 4). Several other potential gas accumulations are present in Texas and are not considered in this study, particularly those at greater depths because they are considered too speculative. Production from these formations would mean that net water use, instead of decreasing after the peak of 145 Mm^3 (117 kAF) in 2020–2030, could remain at that level or possibly higher for a longer time. Also, projections in this study are based on current fracking technologies; new or updated technologies could reduce reliance on fresh water, including use of fluids other than water (e.g., propane, N_2, CO_2), sonic fracturing with no added fluid, and other waterless approaches with specialized drilling tools.[21,22] As the cost of water increases, these methods, potentially more expensive than water fracks, could become more attractive.

Impact of Water Use on Water Resources. Impacts of water use for shale-gas production depend on local water availability and competition for water from other users. Precipitation is variable among Texas shale-gas plays, with mean annual precipitation of 1320 mm/yr (Haynesville), 790 mm/yr (Barnett), and 740 mm/yr (Eagle Ford).[23] Texas is also subject to drought/wet period cycles that may become more extreme with climate change. High precipitation in East Texas results in widespread surface water availability in the Haynesville Shale region, although its use can also impact streamflow;[24] however, most surface water is allocated, although temporary water rights can be obtained from the State. Surface water is also available in the Barnett Shale, including major rivers (Trinity and Brazos Rivers) and reservoirs; however, population growth will increase demand for this resource[11] and possibly compound stress on the aquifer whose water levels have significantly declined in past decades.[25] Surface water is not as readily available in the Eagle Ford Shale region. Several streams are ephemeral and recharge underlying aquifers (Frio and Nueces Rivers). Even when surface water is available in a region, it is often not located adjacent to shale-gas development and trucking or piping of water may be required. Although surface water is generally more renewable than groundwater, it may not be as reliable because of impacts of droughts.

Groundwater resources are generally available in each of the shale-gas plays, and, unlike surface water, groundwater is ubiquitous and generally available close to production wells. The Carrizo Wilcox and Queen City/Sparta aquifers currently provide water for the Tx-Haynesville and Eagle Ford shales. Groundwater is more readily available in East Texas, the only competition for water use in this region being industrial and municipal demands, but conflicts with other users may arise because the shallower aquifer has limited yield.[19] In the Eagle Ford Shale region, groundwater has already been partially depleted for irrigation in the Winter Garden region of South Texas, resulting in water-level declines ≥60 m over a 6500 km^2 area, disappearance of several large springs, and transition from predominantly gaining to mostly losing streams.[26] Overabstraction of groundwater in the past for irrigation limits water availability for current and future shale-gas production. The east part of the Barnett Shale overlies the Trinity aquifer, which provides water in this region.[11] Farther west, no named major or minor aquifer exists.

The large number of hydraulically fractured wells in Texas (≥20 000) and high water use per well create the perception of large rates of water use. However, water use for shale-gas production is relatively minor (<1%) when compared to that for mostly consumptive irrigation (56%) and municipal (26%) water use in Texas in recent years. Nevertheless, water use for shale gas represents a much greater percentage of total water use over smaller areas (Table 2). Net water use for Barnett Shale core areas represented 4% of total water use in 2008.

Total net water use in core/assumed core areas of the plays is 645 Mm^3 (520 kAF) in the Barnett Shale, 69 Mm^3 (55 kAF) in the Tx-Haynesville Shale, and 100 Mm^3 (80 kAF) in the Eagle Ford Shale. The estimated groundwater fraction of total water use is 11% in Barnett, 38% in Tx-Haynesville, and 18% in Eagle Ford shale plays. Municipal water use is dominant (≥85%) in the footprint of the Barnett play in Denton and Tarrant counties and in Webb County in the footprint of the Eagle Ford play. Elsewhere water use is mixed with some irrigation and manufacturing. As compared to all county water use in 2008, net water use for shale-gas production at the county level for selected counties is projected to increase from 1% to 40% for the Barnett, 7% to 136% for the Tx-Haynesville, and 5% to 89% for the Eagle Ford in their peak years (Table 2, Supporting Information, J). The large percentage increases in water use for rural counties reflect the low initial water use in these counties (Figure S13).

Unlike municipal water use, which increases steadily with population growth, shale-gas water use represents a transient demand over ~30−40 yr. The challenge is to understand whether large aquifers, such as the Carrizo aquifer that has extensive groundwater reserves, can recover from the transient stress rapidly enough to support additional demand from population growth. For example, water levels in the Carrizo aquifer in the footprint of the Eagle Ford play have slowed their decline following the heavy irrigation pumpage of the 1960s and 1970s.[27] The less prolific Trinity aquifer overlapping the Barnett Shale footprint is still recovering from decades of pre-1950s heavy municipal pumpage.[25] The State of Texas strongly supports water planning through an array of mostly local government-like entities. The diverse stakeholders have agreed on acceptable groundwater-level declines (called desired future conditions) translated to total annual pumping (based on groundwater modeling) of 350 Mm^3 (285 kAF) from the Carrizo aquifer in the Eagle Ford Shale, to be compared to the projected annual peak of 58 Mm^3 (47 kAF) (20% additional use) for fracking (Supporting Information, J).

To mitigate increased fresh water use, some operators have started exploring brackish groundwater (lower salinity than seawater), despite limited information on this resource[28] and additional constraints, such as contamination risks during transport and increased potential of well corrosion. Development of advanced additives allows higher salinity water to be used for fracking, although ionic composition is still a limitation. In many places, brackish water is available at relatively shallow depths[29] below or above the main fresh-water aquifer. However, financial resources need to be assigned to study these aquifers to better explain their yield, water quality, sustainability, and relationship with the fresh-water section of the same aquifers.

Water Use for Shale Gas Relative to Other Energy Users. Because of limited water resources and ever-growing energy demands, quantifying water-use efficiency per raw fuel source in terms of energy content relative to other energy sources (oil, coal, uranium) is important. No recent authoritative work has documented current energy water use efficiency. Previously published work, such as DOE[30] and Gleick,[31] relies on outdated statistics. In addition to lack of recent data, difficulties arise because of varying water-use patterns. Water consumption for coal mining or makeup water for in situ recovery of uranium is distributed throughout the life of mining operations or possibly toward the end during reclamation. Fresh water use for water flooding and other enhanced oil recovery (EOR) operations is also distributed mostly during the course of oil production, with perhaps heavier use early in the operation (Supporting Information, K). On the other hand, water use for shale gas occurs mostly early in production (notwithstanding refracking), and "ultimate" water efficiency, as calculated at the end of the life of the well or of the play, differs from "instantaneous" (~annual) or "cumulative" water efficiency. The assumed ultimate water efficiency for shale gas is a function of the play's EUR. Considering only production to date, Texas shale gas has a cumulative water use efficiency of 8.3—10.4 L per gigajoule (L/GJ) if auxiliary consumption (drilling and sand mining for proppant production) is added. Mantell[32] provided shale-gas water use efficiency for a large company operating in Texas and elsewhere but likely representative of the industry, and proposed an ultimate water efficiency of 4.8 L/GJ for the Barnett Shale and 2.3 L/GJ for the Tx-Haynesville Shale. Ultimate and cumulative water use efficiency values should converge, provided that projected EURs are correct. Overall, data collected in this study (including 8.3−16.6 L/GJ for coal and 6.1 L/GJ for uranium) show that net water use for shale gas is within the same general range as that for other energy sources (Supporting Information, K).

Implications of this Study for Other Potential Shale-Gas Regions. Texas has dominated shale-gas production in the U.S. during the past decade, with the Barnett Shale being the sole producer in the early 2000s and accounting for ~66% of U.S. production 2007−2009. Because shale-gas production in Texas began much earlier than in other plays in the U.S. and elsewhere and because Texas is the top shale-gas producer in the U.S., the methodology and information on water use from this study should provide insights into projected water use in other developing or potential shale-gas plays. Water use per well varies markedly within and between plays; however, water use per length of production interval (water-use intensity) has a much smaller range (9.5−14 m^3/m, 770−1120 gal/ft) and, consequently, is a more powerful parameter to consider. Past projections for water use in the Barnett Shale are consistent with subsequent water-use data 2006−2011, providing confidence in the approach used in the study to project water use. Studies of new plays with limited development or researchers with limited access to data could make use of the range of numerical values of parameters obtained in this study and needed for preliminary estimates of water use (Supporting Information, L).

Despite the low overall net water use fraction, impacts of water use can be much greater at smaller spatial scales. Projected net water use at peak time could more than double net water use in Texas rural counties, where current demand is low. Climatic conditions for plays in Texas range from humid to semiarid. Although water is more readily available in humid settings, most is already allocated for other uses. Water is more limited in semiarid regions because of overexploitation for irrigation. Limited fresh-water resources, both surface water and groundwater, will be an important issue for shale-gas development in the semiarid southwestern U.S. Although shale gas has not been produced in large quantities outside North America, estimated reserves are high in many countries, particularly northwest China, Mexico, South Africa, and Australia;[16] however, many of these regions correspond to areas of physical water scarcity.[15] Increasing use of brackish-water resources, using produced water, and developing less water-intensive technologies to reduce reliance on water for

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fracking should allow shale-gas production in these water-scarce regions.

■ ASSOCIATED CONTENT

S Supporting Information

Details discussing mining water use with additional figures, information on units used in this work, and glossary. 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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Environmental Science & Technology:

Water Use for Shale-Gas Production in Texas, US

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Supporting Information:

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26 numbered pages

14 figures

6 tables

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Figures:

Units:

There are numerous volume units even in the SI system, and, in addition, each engineering field uses its customary units—barrel (bbl) and thousand cubic feet (Mcf) in the oil and gas industry, million gallons (Mgal) and acre-feet (AF) in the water industry with the added complexity that “m” or “M” often represents thousand and “MM” represents million in the oil and gas industry, whereas “M” represent million or mega in the water industry. We used m^3 and derivative units in the main text with customary English unit equivalents that are also summarized below. Energy units are also numerous, and we used SI units. SI units require the following prefixes: M, mega for million, G, giga for billion, T, tera for thousand billion.

Mgal = mega gallon = million gallons; 1 Mgal = 3785 m^3
Mm^3 = mega m^3 = million m^3
Gm^3 = giga m^3 = billion m^3 = 1 km^3
kAF = thousand acre-feet; 1 kAF = 1.23 Mm^3 = 326 Mgal
GJ = giga joule = billion joules
MMBtu = million British thermal unit; 1 MMBtu = 1.055 GJ
Mcf = thousand cubic feet; 1 Mcf = 1×10^3 cf = 28.3 m^3
MMcf = million cubic feet; 1 MMcf = 1×10^6 cf = 0.0283 Mm^3
Bcf = billion cubic feet; 1 Bcf = 1×10^9 cf = 28.3 Mm^3
Tcf = Tera cubic feet; 1 Tcf = 1×10^{12} cf = 28.3 Gm^3
Tm^3 = Tera cubic meter; 1 Tm^3 = 1000 Gm^3 = 1×10^{12} m^3

Glossary

Core area: limited spatial area of a play with the highest productivity.

Depressurization: process by with water from an aquifer underlying an open-pit mine must be withdrawn to decrease its pressure and avoid negative impacts

Enhanced Oil Recovery (EOR): process by which chemicals (CO_2, solvents, polymers, etc.) are injected into a reservoir in order to produce more oil; also called tertiary recovery. It is typically undertaken after primary recovery (mostly pressure-driven) and waterflooding.

Estimated Ultimate Recovery (EUR): estimated amount of oil or gas potentially recoverable from a play (play EUR) or a well (well EUR).

Hydraulic fracturing *(sometimes spelled fracing or fracking)*: a stimulation method performed in low-permeability formations consisting of creation of a connected fracture network by increasing formation pressure (typically with high-rate water injection).

Completion: suite of operations to bring a well bore to production (including stimulation) after it has been drilled.

Lateral: approximately horizontal leg of a so-called horizontal well bore. It generally stays in the target formation and follows its dip.

Proppant: material added to frac fluid, whose role is to keep fractures open after pressure subsides. Generally made of fit-for-purpose sand grains.

Proppant loading: proppant mass divided by water volume.

Stimulation: a treatment method to enhance production of a well (including hydraulic fracturing).

Waterflood / waterflooding: process by which water, generally saline water previously produced from other wells but sometimes fresh water, is injected into a reservoir to produce more oil; also called secondary recovery

Water use vs. net water use/water consumption: all projected water volumes related to fracking and discussed in the main paper and the Supporting Information are consumptive, comparison to uses outside of the upstream oil and gas industry are also mostly consumptive but not always.

Water-use intensity: amount of water used per unit length (water use divided by length of vertical or lateral productive interval).

In the remainder of this supporting-material section we follow the general organization of the paper. Heading numbering refers to citations in the main text.

Conversion to English Units of Tables 1 and 2

Table S 1. Table 1 from main paper reproduced in English units

Formation	*Area (mi^2)*	*Use (kAF)*	*Wells*	*WUW (Mgal)*	*WUI (gal/ft)*	*Proj (kAF)*
Barnett	18,700	117	14,900	2.8	1000	853
TX-Haynesville	7,400	5.3	390	5.7	1120	425
Eagle Ford	20,400	14.6	1040	4.3	770	1,515
Other Shales						721
Tight Formations						725

Area: total area; *Use*: cumulative water use to 6/2011, *Wells*: number of wells to 6/2011 *WUW*: median water use per horizontal well during the 2009–6/2011 period, *WUI*: median water-use intensity for horizontal wells during the 2009–6/2011 period, *Proj*: projected additional total water use by 2060. "Other shales" are mostly located in West Texas whereas tight formations occur across the state.

Table S 2.Table 2 from main paper reproduced in English units

County			*2008 Net Water Use*				*Projected net Water Use*		
Name	*Population*	*Area (mi^2)*	*Total (kAF)*	*GW (%)*	*SG (kAF)*	*SG (%)*	*Max (kAF)*	*Max (%)*	*Max Year*
Barnett									
Denton[1]	637,400	952	98	13	2.7	2.8	1.7	1.7	2010
Johnson	155,200	727	29	45	8.5	29	3.3	11	2010
Parker	111,600	921	17	49	1.7	10	4.0	23	2010
Tarrant[1]	1,741,00	895	367	5	5.1	1.4	3.1	0.9	2010
Wise	58,500	927	12	42	2.2	19	4.6	40	2010
Eagle Ford									
De Witt	20,200	909	6	86			2.3	35	2023
Dimmit	10,000	1,336	10	88	0.0	0.1	5.4	55	2015
Karnes	15,300	759	5	91			2.0	39	2018
La Salle	6,000	1,481	6	95	0.0	0.1	5.8	89	2019
Live Oak	12,100	1,074	7	66			0.8	12	2024
Webb[2]	238,300	3,394	45	3	0.0	0.0	2.4	5.2	2013
TX-Haynesville									
Harrison	64,200	916	37	11	0.1	0.2	2.7	7.4	2017
Panola	23,300	820	8	37	0.0	0.5	2.4	30	2017
San Augustine	9,000	590	2	30			3.3	136	2017
Shelby	26,200	835	9	27			4.7	55	2017

Name: county name, *Population*: estimated 2008 population, *Area*: county area, *Total*: total net water use, *GW*: estimated net groundwater use as a percentage of total net water use, *SG*: 2008 shale-gas net water use and percentage of 2008 total net water use, *Max*: projected maximum shale-gas annual net water use and percentage of 2008 total net water use, *Max Year*: calendar year of projected maximum.
http://www.twdb.state.tx.us/wrpi/wus/2009est/2009County.xls

[1] Includes City of Fort Worth and other communities relying primarily on imported surface water

[2] Includes City of Laredo

[3]: Assumes that the water originates from the county in which it is used

Historical Water Use

A -Transition to Horizontal Wells (historical water use)

Figure S 1 illustrates the transition from mostly vertical to mostly horizontal wells in the Barnett Shale play. Elsewhere in Texas, some tight-gas plays still have mostly vertical wells, particularly where operators target multiple horizons.

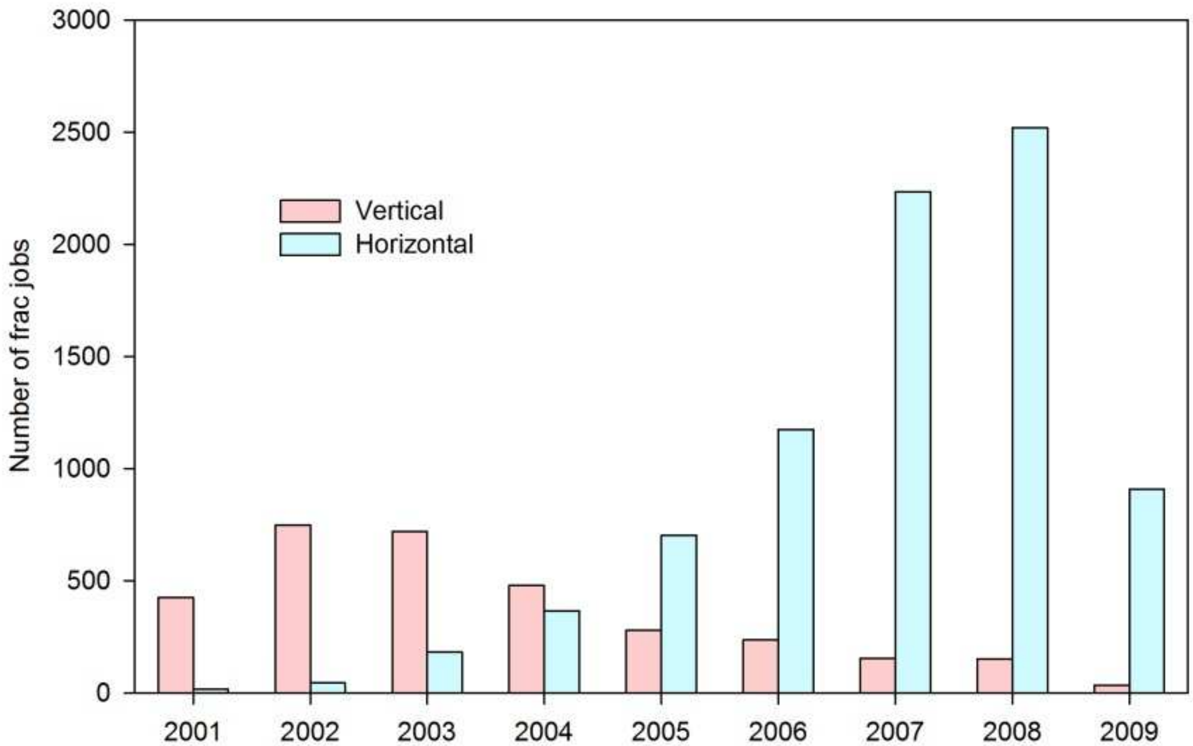

Figure S 1. Vertical vs. horizontal wells in the Barnett Shale play (incomplete data for 2009).

B- Gas Production and Water Use Track One Another (historical water use)

There is a good match between cumulative gas production and fracking water use, illustrating the fact that production needs to be constantly sustained by new wells (Figure S 2).

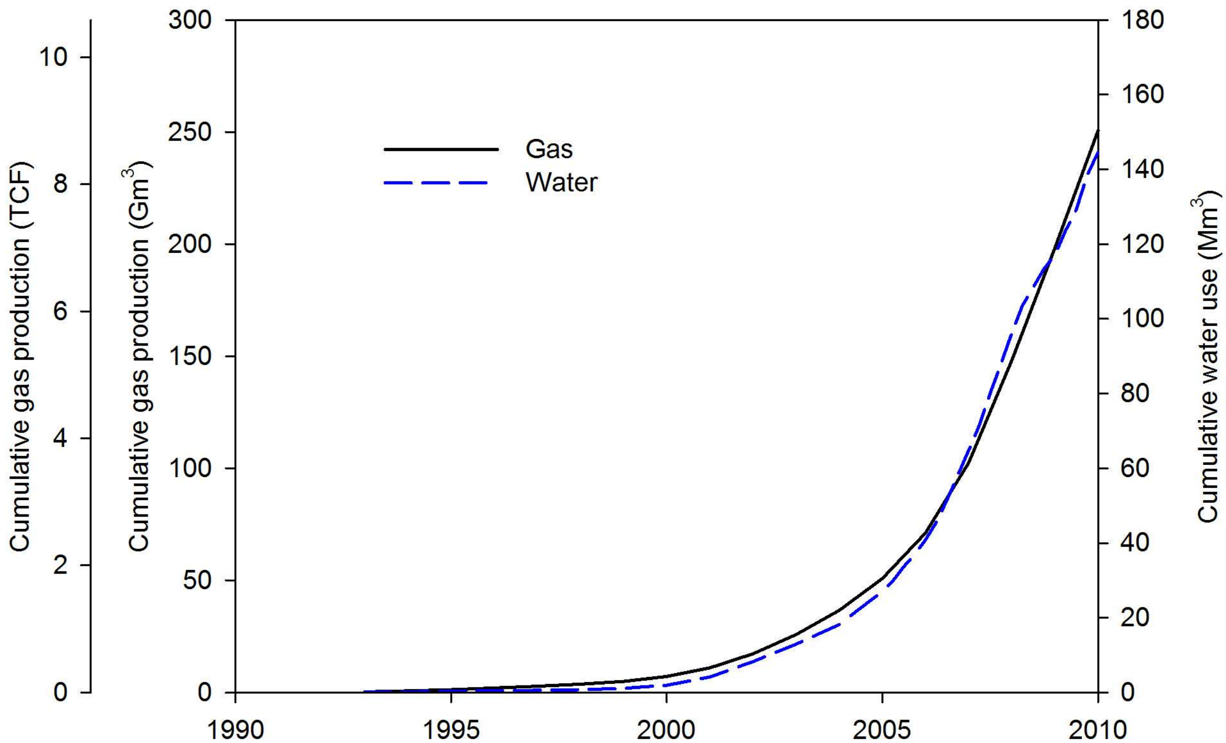

Figure S 2. Cumulative gas production and water use track each other ll in the development / extension phase of the Barnett Shale play.

C- Data Collection (historical water use)

Although the list of all wells drilled and hydraulically fractured is easily accessible, the amount of water used is sometimes not readily available for a fraction of the wells. Table S 3 gives the breakdown in terms of processing raw data downloaded from the vendor database (IHS). Well-completion data from the Barnett Shale are mostly complete, whereas well-completion data for the Eagle Ford and Haynesville Shales are less complete, requiring assumptions to access water use through use of proppant loading and length of laterals.

Wells with water use ⩽380 m^3 (<0.1 Mgal) were omitted from analysis. This threshold is somewhat arbitrary but convenient and was used to distinguish current high-volume frac jobs from simple well stimulation by traditional fracking and acid jobs. They represented two different populations as shown by bimodal or multimodal histograms of water use per well. In 2010, out of all the plays in Texas with some fracking, 3841 wells underwent fracking with a water volume >0.1 Mgal and frequently >>0.1 Mgal (Table 8 in Nicot et al.),[1] 3809 wells, the vast majority of which is vertical, were stimulated with water volume <0.1 Mgal and often <<0.1 Mgal, and 2712 other wells were drilled but neither fracked or stimulated. A quick analysis shows that the wells with mild stimulation do not contribute much to the overall water use: 3809 wells × 0.1 Mgal/well / 0.325851 AF/Mgal = 1170 AF or 1.2 kAF (1.4 Mm^3) at most and actually much less because 0.1 Mgal is the upper bound. This value is to be compared to the >35kAF (45 Mm^3) estimated to be used for high-volume fracking during the same time (Table S 4).

Table S 3. Well count on water-use well data statistics to estimate historical fracking water use.

	Barnett		*Haynesville (TX+LA)*		*Eagle Ford*	
	Wells	*% of Total*	*Wells*	*% of Total*	*Wells*	*% of Total*
Water use and proppant use	3374	97	394	33	279	59
Estimated from proppant use	70	2	150	12	147	31
Estimated from lateral length	43	1	629	52	46	10
Assigned average water use	2	0	32	3	2	0
Total	3489	100	1,205	100	474	100

Period from 1/1/2009 to 12/31/2010

D- Histograms of Water Use and Water Intensity (historical water use)

The following histograms show distributions of frac-water volume and water intensity in the Barnett (Figure S 3), Haynesville (Figure S 4), and Eagle Ford (Figure S 5) shales for selected years. Figure S 6 reproduces the same information and compares plays. The information was used to estimate projected water use. A detailed examination of water intensity through the years suggests that the industry is becoming more efficient and uses progressively less water per unit length of lateral.

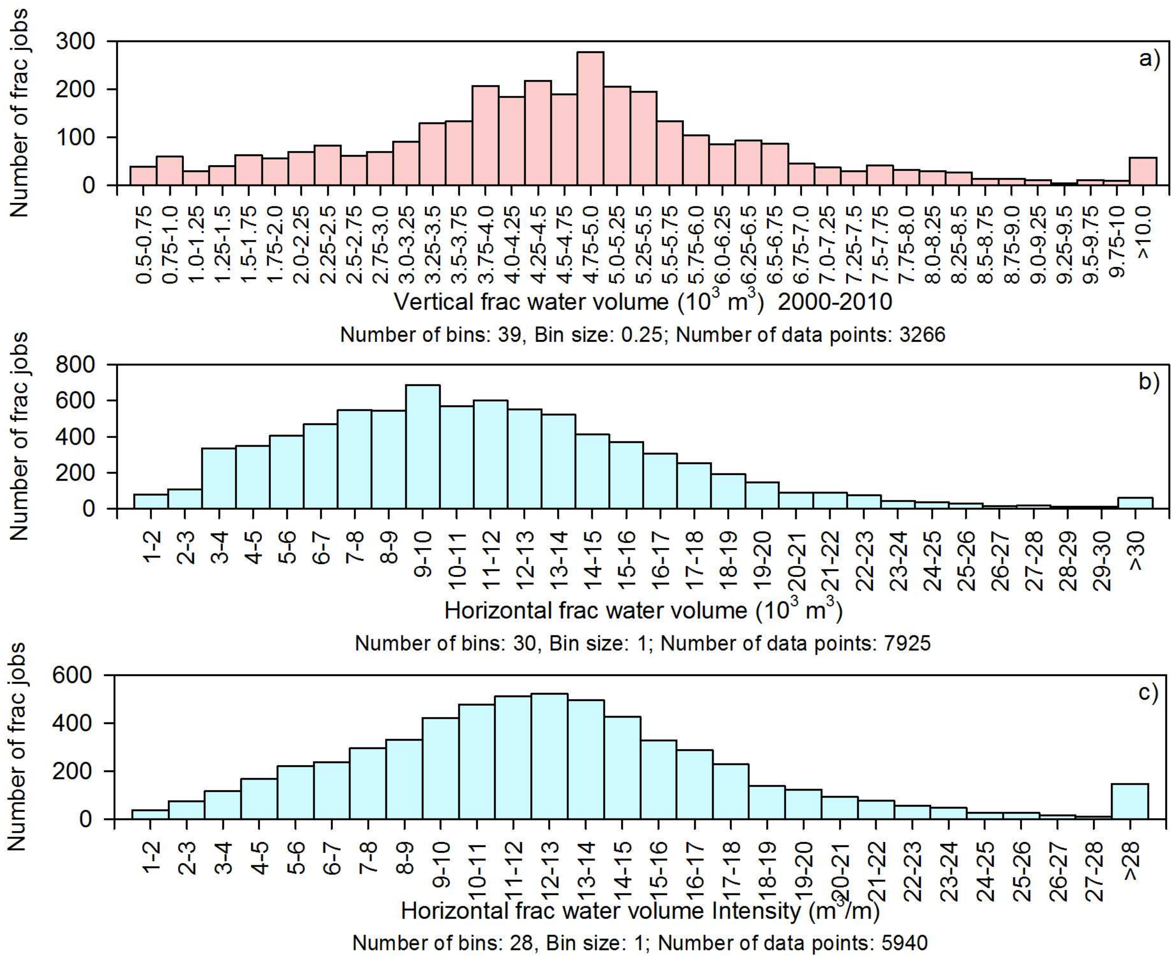

Figure S 3. Histograms of frac water volume for vertical wells, horizontal wells, and water intensity for the 2000–2010 period in the Barnett Shale play (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

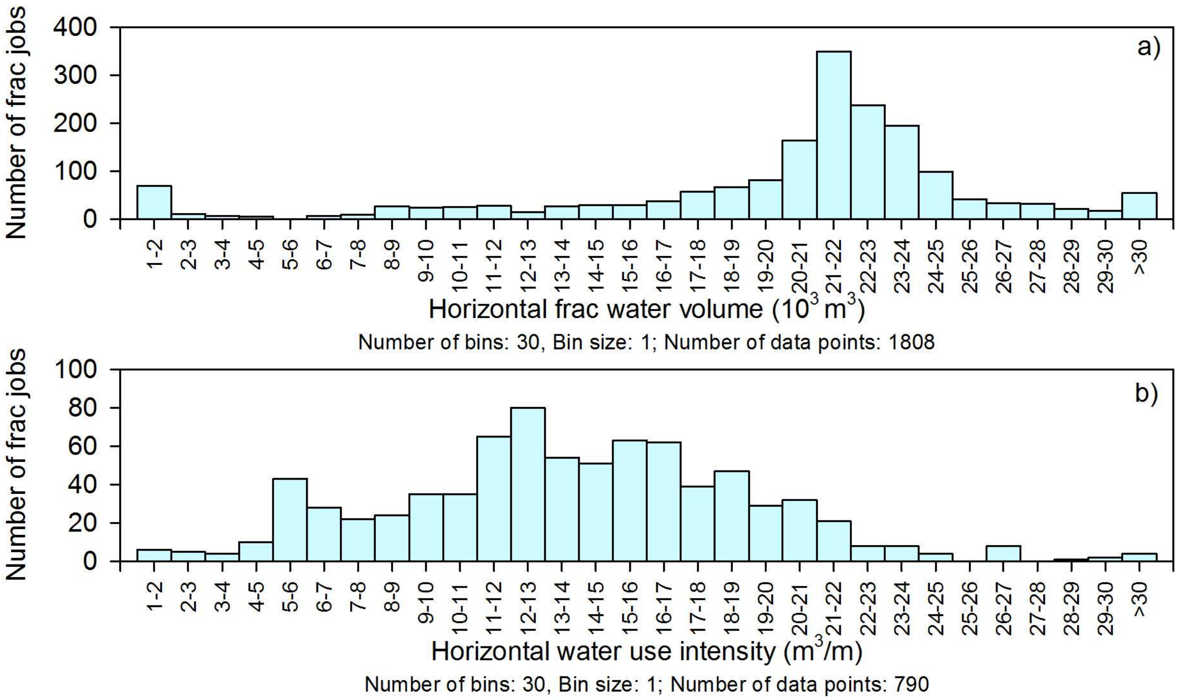

Figure S 4. Histograms of horizontal well frac water volume and water intensity in the Haynesville Shale play (Texas and Louisiana) (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

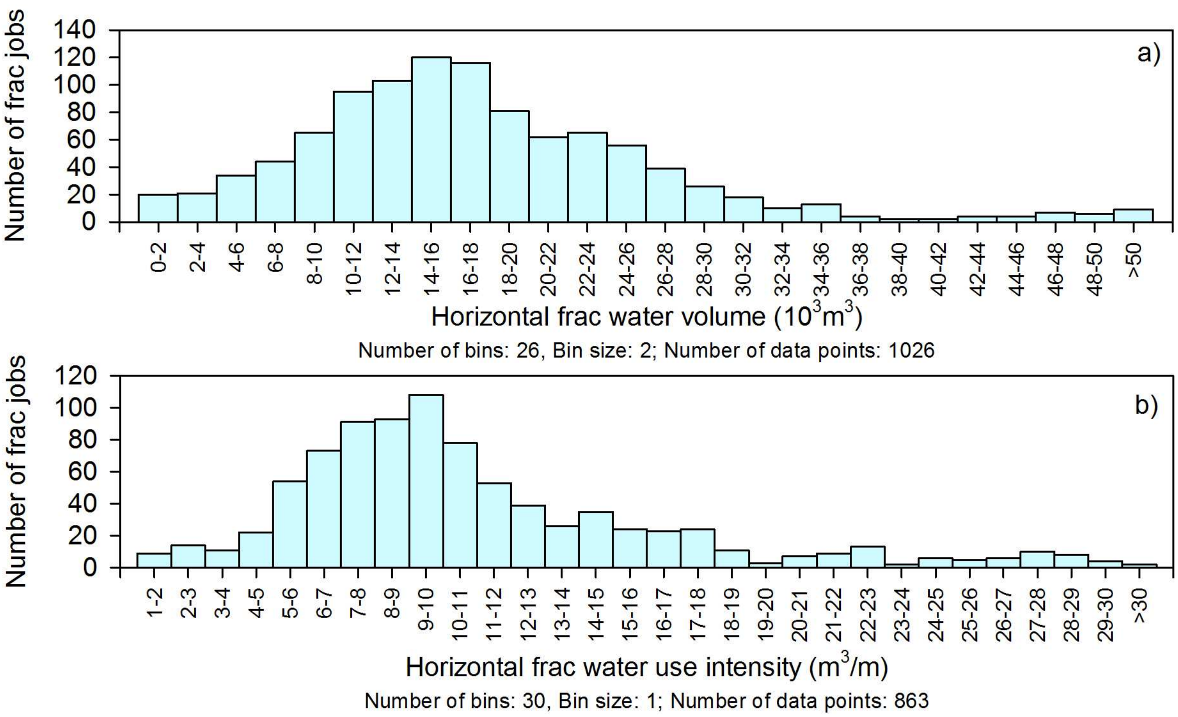

Figure S 5. Histograms of horizontal well frac water volume and water intensity in the Eagle Ford Shale play (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

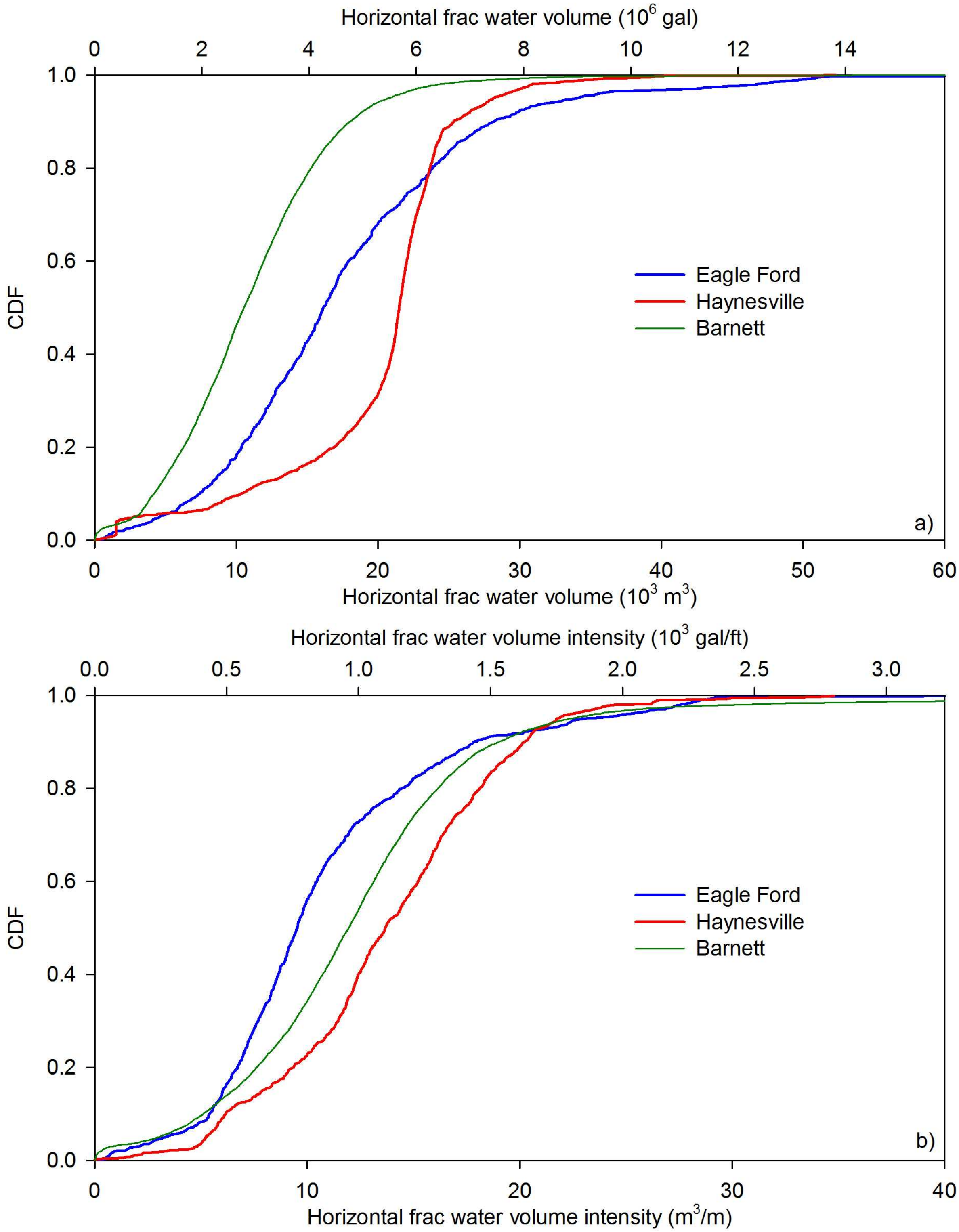

Figure S 6. Data-based cumulative distribution function for horizontal well frac water volume and water intensity in the Barnett, Haynesville (TX+LA), and Eagle Ford Shale plays (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft)

E- Auxiliary Water Use and Recycling (historical water use)

Auxiliary water use related to drilling and proppant mining (sand mining for proppant production) can be counted toward shale-gas development, in addition to fracking.

Drilling water use is variable depending on the play and technological choices of the operator. Well drilling requires a fluid carrier to remove the cuttings and dissipate heat created at the drill bit. The fluid also keeps formation-water pressure in check. Broadly, three types of fluids are used: (1) air, air mixtures, and foams (2) water-based muds, and (3) oil-based muds. Although the most common method involves water-based muds, shale operators tend to rely on the other methods more than the other operators. The amount of water used for drilling varies across plays and, within a play, is operator-dependent. It follows that, water use for drilling shale-play wells is only loosely correlated with depth. Nicot et al.[1] proposed several approaches and suggested an average of 500 m^3 (0.13 Mgal) per well for the ~10,000 wells (40% of which were hydraulically fractured, and 16% of which were shale-gas wells) drilled in Texas in 2008. DOE[2] (p. 64) put forward an estimate of 1500 and 3700 m^3 (400,000 and 1,000,000 gal) to drill a well in the Barnett and Haynesville shales, respectively. Some operators have released specific information about drilling water use, but the amount varies across plays and with different operators.[3] In this rapidly evolving technological field, information quickly become outdated; e.g., Chesapeake[4] listed values of 950 m^3/well (250,000 gal, Barnett), 2300 m^3/well (600,000 gal, Haynesville), and 500 m^3/well (125,000 gal, Eagle Ford); that is, 6.2%, 10.8%, and 2.0% of combined drilling and fracking water use, respectively—lower numbers than those reported by DOE.[2]

Sand for proppant (one use of industrial sand) is often mined from natural sand deposits and requires more water than typical aggregate plants because of the grain-size sorting involved, despite intense water recycling at these facilities. Nicot et al.[1] (p.161) estimated industrial sand/proppant net water use in Texas to be ~2.5 m^3 of water per metric ton of proppant (~600 gal/short ton or 0.3 gal/lb). Combining this statistic with an average proppant loading of 72 kg of proppant/m^3 of frac fluid (0.6 lb/gal) yields a value of 0.18 m^3 of water for proppant production per m^3 of frac fluid (0.18 gal of water for proppant production per gal of frac fluid).

Overall, these two additional water uses (drilling and sand mining) amount to an additional ~25% of water use relative to water used solely for fracking. Note that some deep plays such as the Haynesville Shale use man-made ceramics proppant and that some of the proppant can be imported from out of state.

Recycling and reuse of fracking fluids are possible only on the fraction flowing back to the wellhead. This fraction is variable and a function of the play, location within the play, and of the fracking operational details. Operational issues also render the use of flowback/produced water feasible only early in the history of the well (weeks). It follows that the usable water volume is lower and sometimes much lower than the total water volume that flows back. Mantell[3] reported that 10 days after fracking, only 16% and 5% of the frac fluid had been recovered in the Barnett and Haynesville shales, respectively, although ultimately about 3 to 1 times the injected volume will be produced from the same plays during the life of the wells in these plays. Another important parameter is water quality; in some cases treatment of flowback water is not economical, and the best approach to dispose of flowback water is deep well injection. Nicot et al.[1] estimated that, in the past few years, recycling water use was within the 5–10% range in the Barnett and ~0% in the Tx-Haynesville shales. No information was collected for the Eagle Ford Shale. Ultimately, the level of reuse and recycling may revolve around economics relative to other options such as deep well injection, which is commonly used in Texas.

Projected Water Use

F- Prospectivity Factor (projected water use)

A prospectivity factor is assigned to each county (or portion of county within the play footprint). It varies in the 0-1 range. A factor close to 1 is typically assigned to counties in the core area decreasing to 0 at the edge of the gas shale footprint. The prospectivity factor is one of the least known parameters and it gives a competitive edge to the companies with a good knowledge of it. Prospectivity factor includes assessment of characteristics that are readily available such as shale depth and thickness but also elements or features such as amount and type of organic matter, thermal maturity, burial history, microporosity, and fracture spacing and orientation. Prospectivity factor also includes impacts of cultural factors such as urban or rural environment. Although not an issue in Texas, it could also account for difficulties with local topography. By definition the value of the prospectivity factor is subjective but based on limited objective information on the elements listed above. The county-level estimates used in this work relied on educated estimates resulting from discussions with expert geologists.

G- Distribution of Water use through Time (projected water use)

Temporal distribution of water use may be as complex as allowed by data availability. A very simple methodology would consist is estimating the life of the play (for example, 20 or 40 years) and assuming a constant rate of drilling/fracking through time and space. In this paper, drilling/fracking rates are considered variable through time and are characterized by a start year, a peak year, and an end year at the county level. The start year is either in the past if drilling is already active in the county or in the future if no well or only a few wells have been drilled. The start year is assigned as a function of the prospectivity, that is, a more prospective county will have an earlier start year than a less prospective county. Peak year is approximately 10 years after the start year and is followed by a long tail of approximately 20 to 50 years until high-volume fracking stops in the county. Those values were derived from a more detailed work done on the Barnett Shale and assumed valid for the state as a whole.[1] The number of wells fracked in the peak year is a function of the prospectivity of the county. The four parameters for each county (start year, peak year, end year, and number of wells fracked at peak year) are then iterated until (1) the overall number of fracked wells is consistent with the number of drilling rigs available in the play (in general 50 to 250 rigs) and the "spud-to-spud" time interval (time between time zero of successive wells, 2 to 5 weeks depending on depth, play and operator) and (2) the overall peak year of the play is somewhat consistent with the projected evaluation of the plays as published in the public domain by oil and gas companies, think tanks, and other consultancies (well and play EURs, IPs).[1]

H- Assumption of No Refracking (projected water use)

This study assumes that all possible refracking has already been done and that there will be no need to refrac newer wells. Access to refrac information in Texas is not as straightforward as that for initial completion. How much refracking of wells already fracked is occurring or will occur is unclear, and the information is conflicting. Vincent[5] did a systematic study of refracking from the beginning of hydraulic fracturing and concluded that refracking works in some areas and not in other areas (note that successful or unsuccessful fracs use the same amount of water). Cases where refracking works are well documented in the literature and cases where refracking does not work are not documented as often. However, discussions with operators suggest that very little refracking of recent or future wells will occur. Refracking activities so far have been restricted to wells completed early in the development of the slick-water fracking technology and, thus, may be more common for vertical wells. Potapenko et al.[6], evaluating Barnett recompletions, found that despite great success with refracking of vertical wells, little success has come from refracking of horizontal wells. Gel fracs performed early in the history of the play may have damaged the formation, and new water fracs have restored its full potential.[7] Sinha and Ramakrishnan[8] suggested that 15-20% of the Barnett Shale horizontal wells have some attributes that make them suitable candidates for refracking. Eventually, the impact of refracking will be a function of the future price of natural gas, with a higher price likely leading to more refracs.

I- Additional Plays—State-Level Water-Use Projections (projected water use)

In addition to the three plays considered in this study (Barnett, Haynesville, and Eagle Ford shales), several others have growing potential, as well as many more tight plays. Tight plays are whole or portions of conventional reservoirs with very low permeability (<1 md) (Figure S 7). Tight gas plays represented the bulk of fracking before development of shale gas. Wells in these tight plays tend to be vertical; however, many are horizontal. Table S 4 shows the water-use breakdown by mining category in Texas for 2008, the last year with a complete data set. Figure S 8 displays the same information in a column chart. Figure S 9 illustrates the fact that mining (including fracking) water use (mostly consumptive) is a small fraction of total water use in Texas (mostly consumptive). The projections assume that extrapolation from current trends is appropriate. Unpredictable events, by their nature, are not included, and the multiplicity of potential scenarios quickly becomes unmanageable: what year does it begin, how rapidly does it develop, is it permanent or transient, what is the magnitude of the impact, etc.? Including uncertainty in changes in water-use projections is extremely difficult; therefore, our approach focused on a single best estimate. Figure S 10, Figure S 11, and Figure S 12 illustrate water use (mostly consumptive) through time for the entire mining industry, oil and gas sectors, and fracking only, respectively.

Table S 4. State-level 2008 water use, mostly consumptive, in the mining industry (not including any postmining processing water use).[1]

	Hydraulic Fracturing	*EOR*	*Drilling*	*Coal*	*Crushed Stone*	*Sand & Gravel*	*Industrial Sands*	*Others*	*Total*
Mm^3	44.7	16.0	9.9	24.5	65.7	22.6	12.0	1.6	197.0
kAF	36.2	13.0	8.0	19.9	53.3	18.3	9.7	1.3	159.7
Mgal	11.8×10^3	4.2×10^3	2.6×10^3	6.5×10^3	17.4×10^3	6.0×10^3	3.2×10^3	0.4×10^3	52.0×10^3

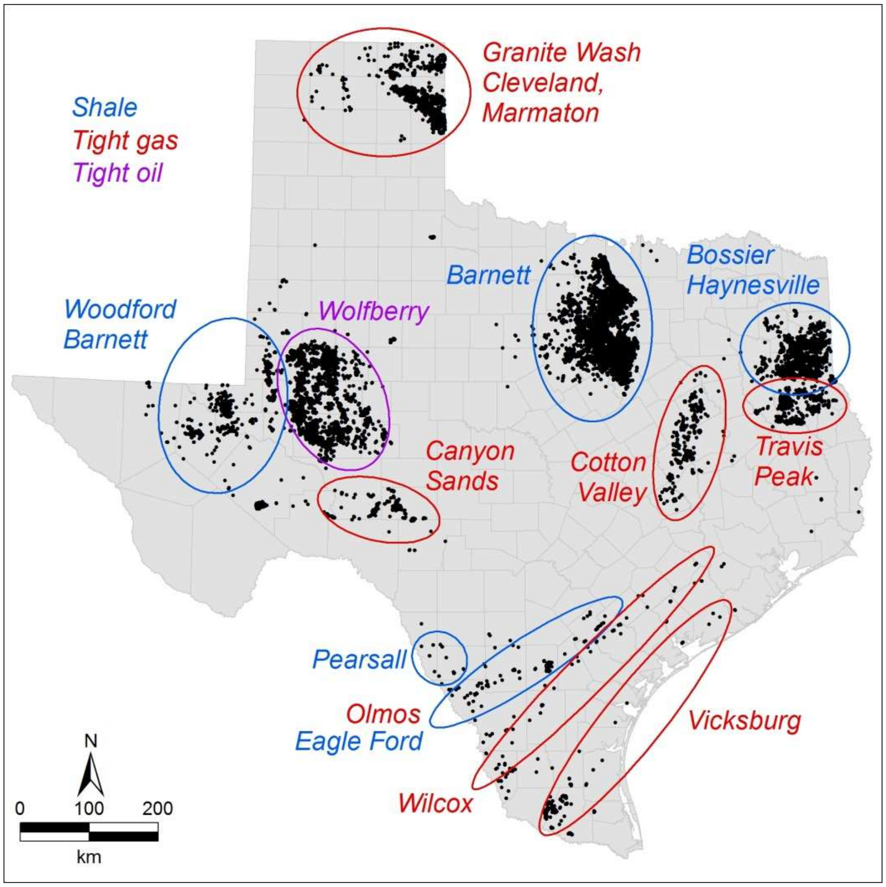

Figure S 7. Map showing locations of all frac jobs in the 2005–2009 time span in Texas. Approximately 23,500 wells are shown.

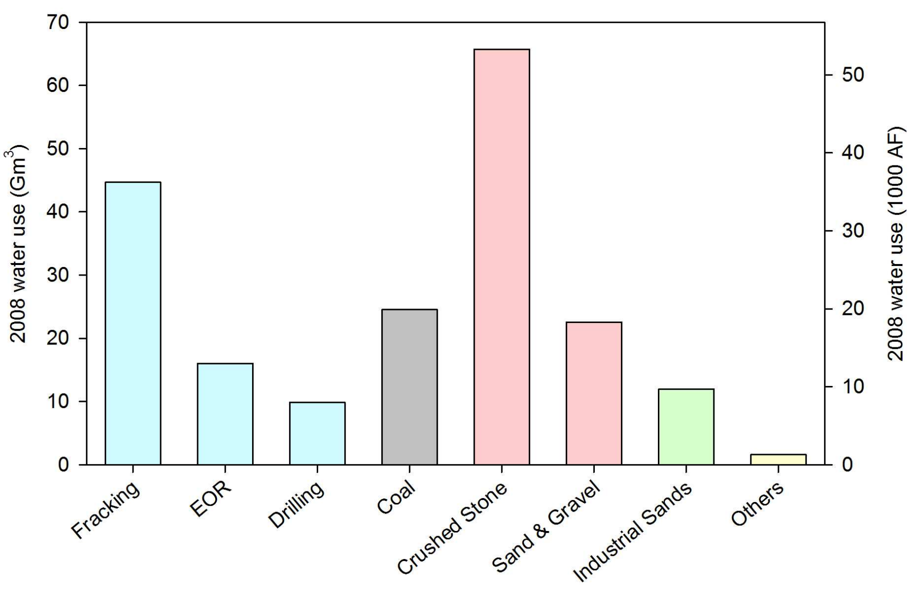

Figure S 8. Summary of 2008 water use by mining category in Texas (all sources). All categories are consumptive except some coal operations withdrawing water from aquifers (that is, consumptive for the aquifers) and redirecting them to surface water bodies.

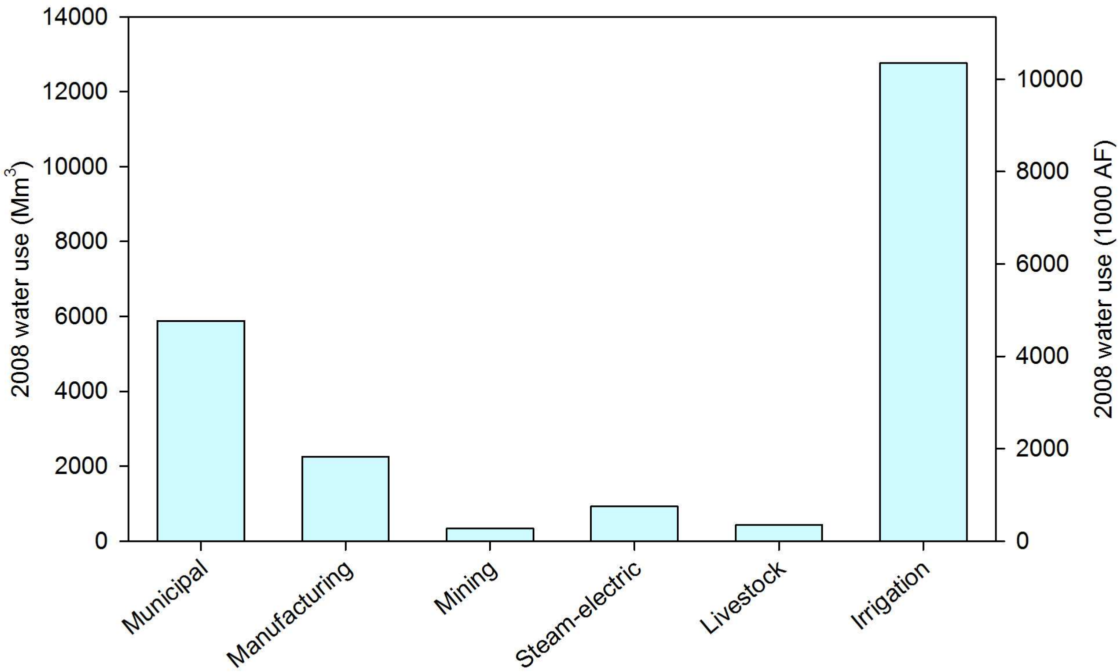

Figure S 9. Summary of 2008 overall water use in Texas. Irrigation, livestock, steam electric, and mining are overall consumptive. Water use for municipal and manufacturing is only partly consumptive because some of the water is returned to surface water bodies (lakes, rivers) and could be used again.

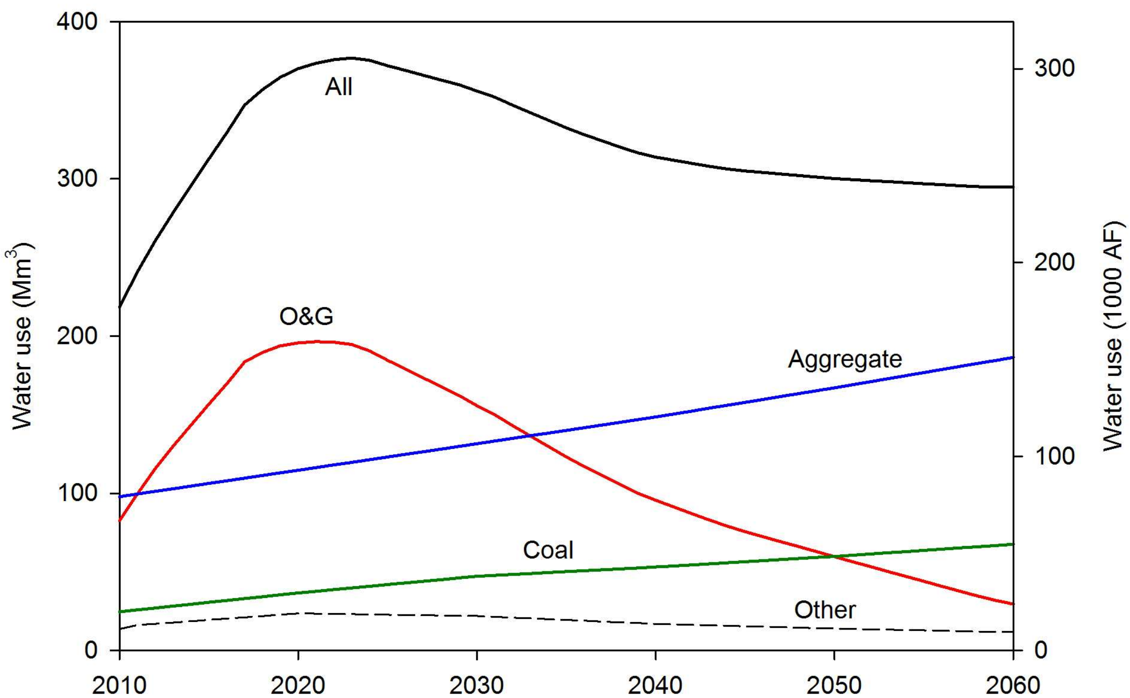

Figure S 10. Summary of 2010–2060 projected net water use in the mining industry segment (some coal water use can be considered as non- consumptive).

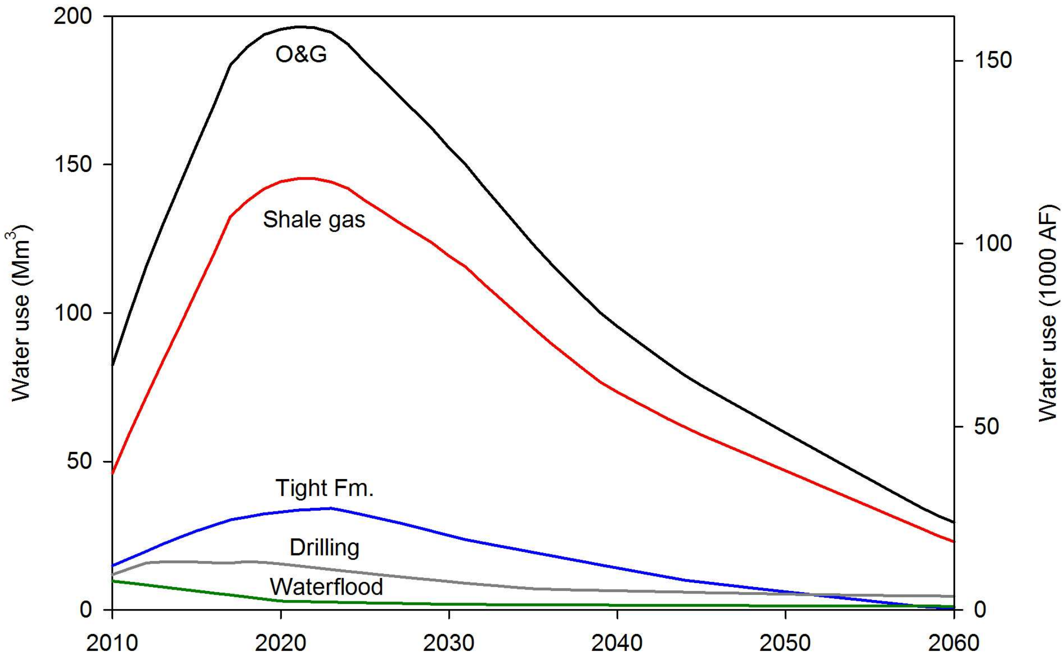

Figure S 11. Summary of 2010–2060 projected net water use in the oil and gas segment.

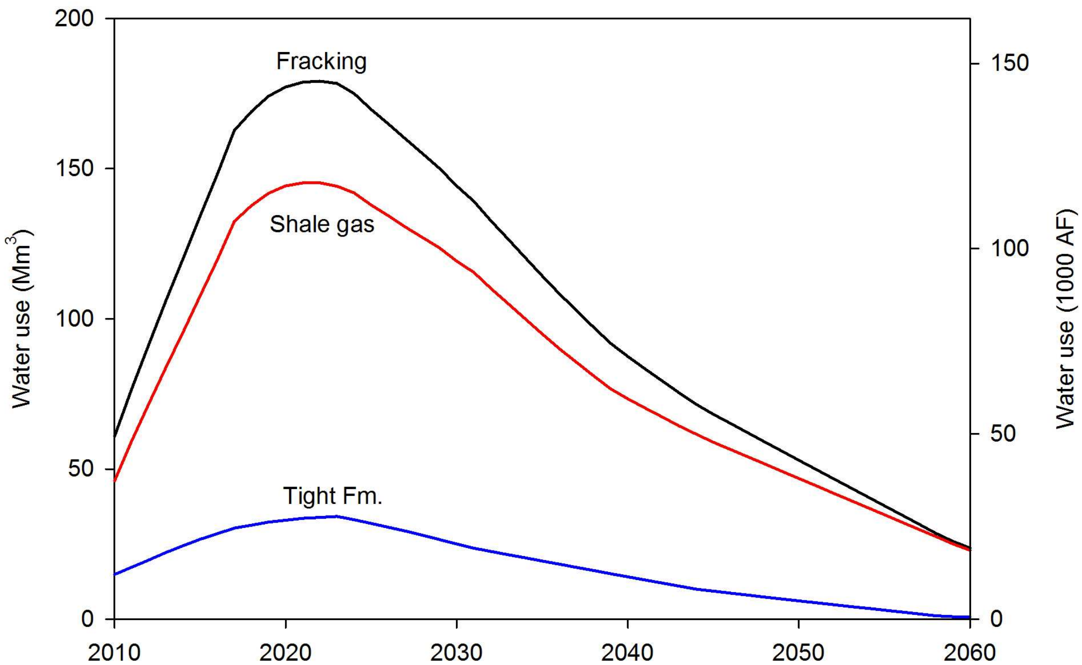

Figure S 12. Summary of 2010–2060 projected fracking shale-gas and tight-formation net water use.

J- Hydraulic-Fracturing Water Use Can be Significant at the County Level (projected water use)

Fracking net water use does not represent a large fraction of total water use (mostly consumptive) at the state level; however, it can represent a significant fraction at the county level, particularly rural counties with low populations, whose main water source is aquifers (Figure S 13). However, projected fracking demand (that can be met from a strictly groundwater-availability standpoint) is not necessarily within the projected net water use agreed upon by local governing bodies, i.e. groundwater conservation districts. At the county level, projected fracking net water use is sometimes larger than projected pumping for all other uses (Table S 5), as illustrated by the following example chosen in the Eagle Ford Shale, where most frac water is derived from groundwater. Karnes County is projected to have a maximum annual fracking net water use of 2.5 Mm^3 (2.0 kAF) and an average fracking net water use of 1.3 Mm^3/yr (1.1 kAF/yr) in 2010–2060. However, local water governmental entities have projected average annual water use for all usages over the 2010–2060 period (not including fracking) of 2.3 Mm^3/yr (1.9 kAF/yr). This value was agreed upon by various entities to protect long-term use of the aquifers. Including (exempted) fracking net water use will increase water use by 56% beyond agreed-upon water use. That is, averaged over the 2010–2060 period, several counties may need to provide more water for fracking relative to all other planned water uses.

Table S 5. Projected county-level water use vs. planned water use through desired future conditions.

	2008 Water Use				*Projected Water Use*				
County	*Total (Mm^3)*	*GW (%)*	*SG (Mm^3)*	*SG (%)*	*Max frac (Mm^3)*	*Max frac (%)*	*Mean DFC (Mm^3/yr)*[1]	*Mean frac (Mm^3/yr)*	*Mean frac (%)*
De Witt	7.9	86			2.8	35.4	18.0[2]	1.5	8.3
Dimmit	12.2	88	0.0	0.1%	6.7	55.1	2.7[3]	3.5	130
Karnes	6.2	91			2.5	39.4	2.3[3]	1.3	56.5
La Salle	8.0	95	0.0	0.1%	7.1	89.2	5.3[3]	3.5	66.0
Live Oak	8.4	66			1.0	12.3	14.2[4]	0.5	3,5
Webb	56.0	3	0.0	0.0%	2.9	5.2	1.1[3]	1.5	136
English Units									
County	*Total (kAF)*	*GW (%)*	*SG (kAF)*	*SG (%)*	*Max frac (kAF)*	*Max frac (%)*	*Mean DFC (kAF /yr)*[1]	*Mean frac (kAF /yr)*	*Mean frac (%)*
De Witt	6.4	86			2.3	35.4	14.6[2]	1.2	8.3
Dimmit	9.9	88	0.0	0.1%	5.4	55.1	2.2[3]	2.8	130
Karnes	5.1	91			2.0	39.4	1.9[3]	1.1	56.5
La Salle	6.5	95	0.0	0.1%	5.8	89.2	4.3[3]	2.8	66.0
Live Oak	6.8	66			0.8	12.3	11.5[4]	0.4	3,5
Webb	45.4	3	0.0	0.0%	2.4	5.2	0.9[3]	1.2	136

Total: total water use, *GW*: estimated groundwater-use percentage of total, *SG*: shale-gas water use and percentage of total, *Max frac*: projected maximum shale-gas annual net water use and percentage of 2008 total water use, *Mean DFC*: mean desired future condition (DFC) pumping 2010–2060, *Mean Frac*: projected mean annual fracking net water use 2010–2060 and percentage of DFC pumping.

[1]De Witt and Live Oak Counties are mostly over the Gulf Coast aquifers.

[2]TWDB, 2011, GAM Run 10-008 Addendum by S. C. Wade; Groundwater Management Area #15 has chosen pumping level corresponding to an average drawdown of 12 ft in the Gulf Coast aquifers over the 2010–2060 period across the whole GMA #15 area; http://www.twdb.state.tx.us/GwRD/GMA/gmahome.htm

[3]TWDB, 2010, GAM Run 09-034 by S. C. Wade and M. Jigmond; Scenario 4 has been retained by Groundwater Management Area #13 to establish DFCs corresponding to an average drawdown of 23 ft in the Carrizo aquifer over the 2010–2060 period across the whole GMA #13 area; http://www.twdb.state.tx.us/GwRD/GMA/gmahome.htm

[4]TWDB, 2011, GAM Run 09-008 by W. R. Hutchinson; Scenario 10 has been chosen by Groundwater Management Area #16 to establish DFCs corresponding to an average drawdown of 94 ft in the Gulf Coast aquifers over the 2010–2060 period across the whole GMA #16 area; http://www.twdb.state.tx.us/GwRD/GMA/gmahome.htm

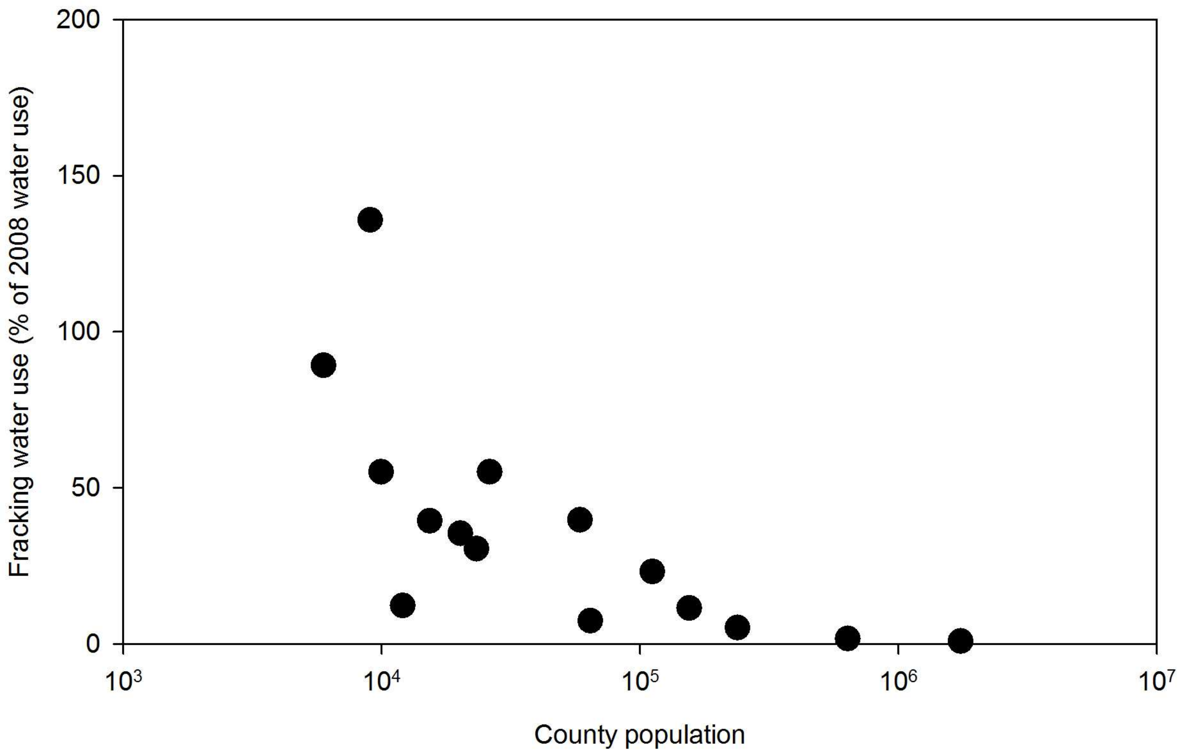

Figure S 13. Fraction of county-level highest annual fracking net water use relative to a 2008 total-water-use baseline in the same county. Counties with low populations should experience a large relative increase in water use because of a low baseline, whereas counties with a large population show a much lower relative increase.

K- Water Efficiency of Energy Fuels

Water efficiency for energy fuels can be computed in multiple ways all based on the ratio of net water use in a given period over fuel production (or its energy content) over the same period. However, depending on the water use and fuel-production pattern (Figure S 14), the ratio for a given fuel may vary. The geographic base used to compute water efficiency and varying water efficiencies through time complicates the analysis. For example, fresh water use for waterfloods (process by which water, generally saline water previously produced from other wells but sometimes fresh water, is injected into a reservoir to produce more oil) has been decreasing constantly for several decades, although the fraction of oil extracted through secondary and tertiary recovery has increased at the same time. Gleick[9] concluded that water efficiency for waterflood oil was >600 liter per gigajoule (L/GJ) (Table S 6). Nicot et al.[1] reported a somewhat lower value of 115 L/GJ in West Texas in 1994. That same value applied to the entire state for the same year at a time with large oil primary production would yield a low value of 5.8 L/GJ. Instantaneous water efficiency as computed in 2008 for oil was 13 L/GJ (8.6 L/GJ when applied to the whole state). Applying fracking net water use to gas production in the entire state in 2008 yields a water efficiency of 4.6 L/GJ. Water efficiency depends also on the granularity of the system, with oil and gas relative to coal representing opposite extremes. Including depressurization (process by with water from an aquifer underlying an open-pit mine must be withdrawn to decrease its pressure and avoid negative impacts) or not affects water efficiency for lignite by a factor of ~8. A mine requiring large-scale depressurization pumping recently closed down[1] and with it, efficiency numbers would have been less favorable.

Table S 6. Texas and overall water efficiency of various fuels (oil, gas, lignite).

	Gleick[9] (1994) DOE[10] (2006) Mantell[11] (2009) (Liter/GJoule)	Nicot et al.[1] (Liter/GJoule)
Oil	3-8 [glk]	
Waterflood – CO_2-EOR	600-640 [glk]	
West Texas, 1994[1]		115
Applied to whole state, 1994 (mixed)[2]		5.8
West Texas, 2002[3]		21.6
Applied to whole state, 2002 (mixed)		14.0
West Texas, 2008[1]		13.0
Applied to whole state, 2008 (mixed)		8.6
Oil refining	25-65[glk]	
Gas	~0 [glk]	
Barnett Shale[4]	4.8 [mtl]	
Haynesville Shale (TX and LA)[4]	2.3 [mtl]	
Texas shale gas (2010)[4]		8.3
Including drilling and proppant mining		10.4
All Texas gas (2010)[5]		4.6
Gas processing[6]	6 [glk]	
Coal (no washing)	3.6-21.6 [doe]	
Coal surface mining (no reclamation)	2 [glk]	
Coal surface mining (reclamation)	5 [glk]	
Lignite (consumption only)		~8.3-16.6
Lignite (depressurization included)		~63-126
Uranium (in situ recovery, no reclamation)		~6.1
Uranium open-pit mining	20 [doe] [glk]	
Postmining processing	26-30 [doe] [glk]	

The following conversion factors were used: 1 bbl oil ~ 5.9 MMBtu; 1 Mcf gas ~ 1 MMBtu; 1 ton lignite ~ 9-18 MMBtu; 1 lb U ~170 MMBtu; 1 MMBtu = 1.055 GJ;

[1]Only counties with significant waterflood

[2]Texas oil production was greater in 1994 (542 million barrels) than in 2002 (365) or 2008 (353)

[3]All counties, assuming that ~two-thirds of the oil was produced through secondary or tertiary recovery (Nicot et al.,[1], p.114)

[4]Mantell[11] estimates include all production to EUR ("ultimate water efficiency"), whereas figures extracted from Nicot et al.[1] include only gas produced during the year for which water use was computed ("instantaneous water efficiency"). Drilling is also included. Mantell[11] also included 1.8 gal/MMBtu for the Fayetteville Shale in Arkansas and 1.05 gal/MMBtu for the Marcellus Shale in Pennsylvania.

[5]2010 water-use fracking for gas wells was 35.2 Mm^3 (28.5 kAF), 2010 total gas production in Texas was 205 Gm^3 (7.25 Tcf) (http://www.rrc.state.tx.us/data/petrofacts/July2011.pdf), with 2010 shale-gas production accounting for about one-third of it.

[6]Not all gas produced requires processing.

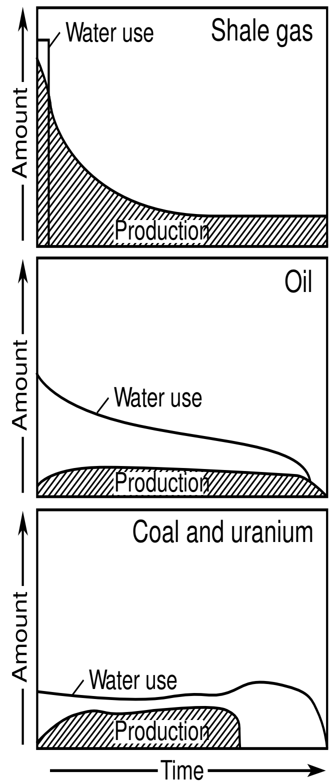

Figure S 14. Illustration of net water-use (water consumption) patterns in various mining industries in Texas. Time frame varies from years to decades. The relative size of the production and water-use curves and the relative size of the three water use curves are only indicative and should not be quantitatively compared with one another. Fracking consumes all water upfront and oil/gas production slowly declines. In the conventional oil production case, the initial amount of fresh water consumed during waterflood and EOR decreases through time as the water produced from the production well is reinjected and as oil production reaches a relative plateau. Typically, both injection and production stop within the same year. Water consumption for coal/lignite production is very variable in Texas, from almost non-existent to large. The figure represents a case with sustained depressurization throughout the life of the facility and the subsequent water needed for reclamation (which lags production by a few years). Uranium mining follows a similar pattern but for different reasons and with a much smaller absolute water volume. Most uranium is produced through in-situ recovery in which chemical are injected with water to leach the uranium from the rock. More water is produced than injected to maintain a negative pressure and avoid contaminant excursion. A cleaning and reclamation period follows.

L- Application of the Methodology to Other Plays

The methodology formulated in this study can be divided into 2 major steps: (1) obtain and process historical data and assess trends in key parameters, and (2) apply a prospectivity factor to obtain an overall water use for the play and then distribute it through time. It is mostly applicable to plays in which horizontal wells are the production method of choice.

The first step is accomplished through data mining of the IHS or another database to obtain the water intensity I (m^3 or gal of water per m or ft of lateral) and its trend through time. Mapping of the boreholes in the areas the most densely drilled allows for an estimate of the lateral spacing d. If the play is new or if the researcher lacks access to databases, ranges of water intensity and of lateral spacing provided in this work can be used as an initial estimate. Now, imagining that some domain of area D is entirely drilled with, in essence, parallel laterals covering the whole domain end to end with a spacing of d, the uncorrected water use Wu for the domain of area D would be: $Wu = D/d \times I$.

In a second step, the prospectivity factor p is applied to the domain of area D to yield a corrected water use factor Wc: $Wc = p \times Wu = p \times D/d \times I$. Details on the prospectivity factor are given in Section F. If the play has already been active, the p factors can be varied between the different domains making up the play (counties in this study), with values close to 1 in the core area to values close to 0 at the edge of the play (keeping in mind that the core is not necessarily at the center of the play). If no information is available, we suggest a prospectivity factor value taken in the 0.2-0.4 range. The water use Wc represents the cumulative amount of water used during the life of the play.

Similar to production from oil and gas reservoirs, water use in a shale-gas play will start with a ramp-up period leading to a peak or a plateau giving way to a slow decrease or tail as infill wells are fracked. It follows that Wc has to be distributed through time (n years with peak at year m) with $w(i)$ annual water use of year i satisfying the following equation:

$$Wc = \sum_{i=1}^{n} w(i)$$

$$w(i+1) = a \times w(i) \quad for\ i < m$$
$$w(i+1) = b \times w(i) \quad for\ i \geq m$$

The constraints simply mean that the time distribution of water use has a triangular shape with ascending and descending straight lines converging at year *m*. if no other information is available, values for parameters *n* and *m* can be extracted from Figure 4 of the main paper. It shows estimated time distribution of projected water use for the three main shale-gas plays in Texas. Note that this approach assumes no refracking (Section H). Water use values $w(i)$ for early time ($i \leq 10$) have to be consistent with the average time to drill a well and the anticipated rig count (Section G) in the play, itself consistent with the rig count of the multi-state region competing for rigs. Finally, recycling/reuse (Section E) is added to the estimated water use through a time varying factor $r(i) \leq 1$. This study assumes that *r* varies from 1 when no recycling/reuse occurs to 0.8 for the Barnett and Eagle Ford shale plays in 2060 (that is, 20% of the water injected is recycled/reused). The net water use for year *i* is $r(i) \times w(i)$ and the total net water use W_{net} in the domain *D* is:

$$W_{net} = \sum_{i=1}^{n} r(i) \times w(i)$$

The net water use W_{net} can then be compared to local surface water and groundwater use. All final projection results presented in this work are net water use (W_{net}).

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