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Depressurization: process by with water from an aquifer underlying an open-pit mine must be withdrawn to decrease its pressure and avoid negative impacts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

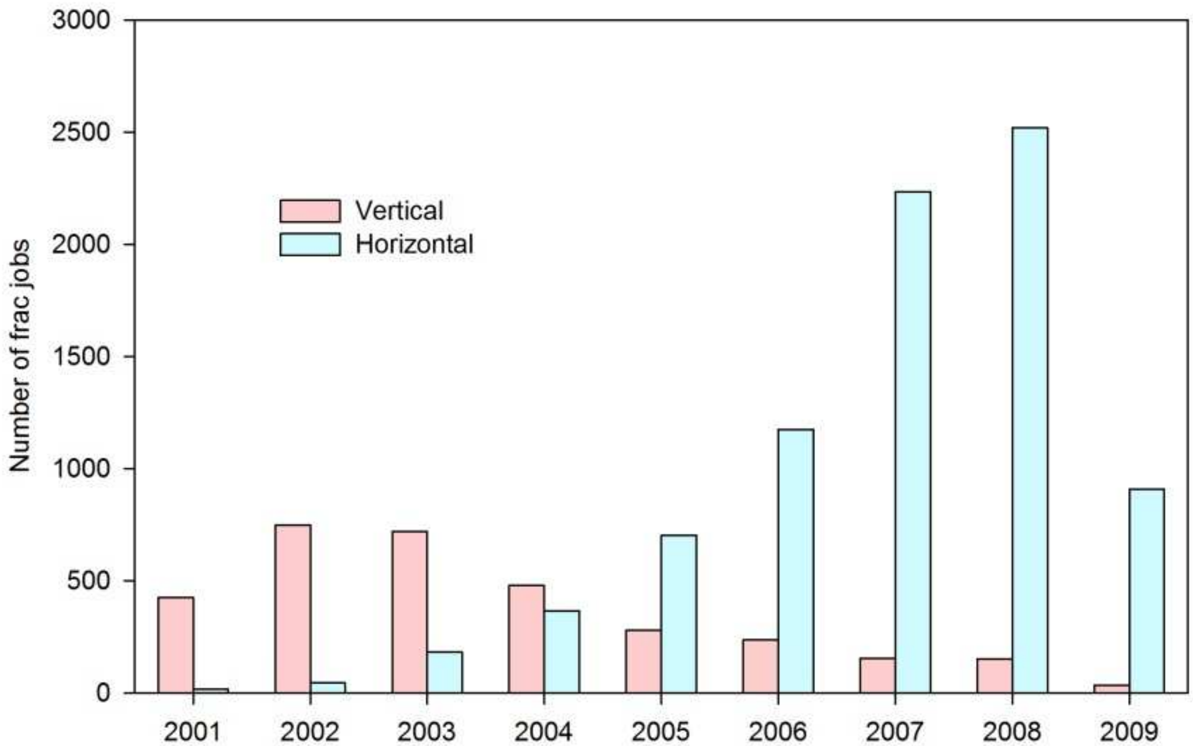

Figure S 1. Vertical vs. horizontal wells in the Barnett Shale play (incomplete data for 2009).

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).

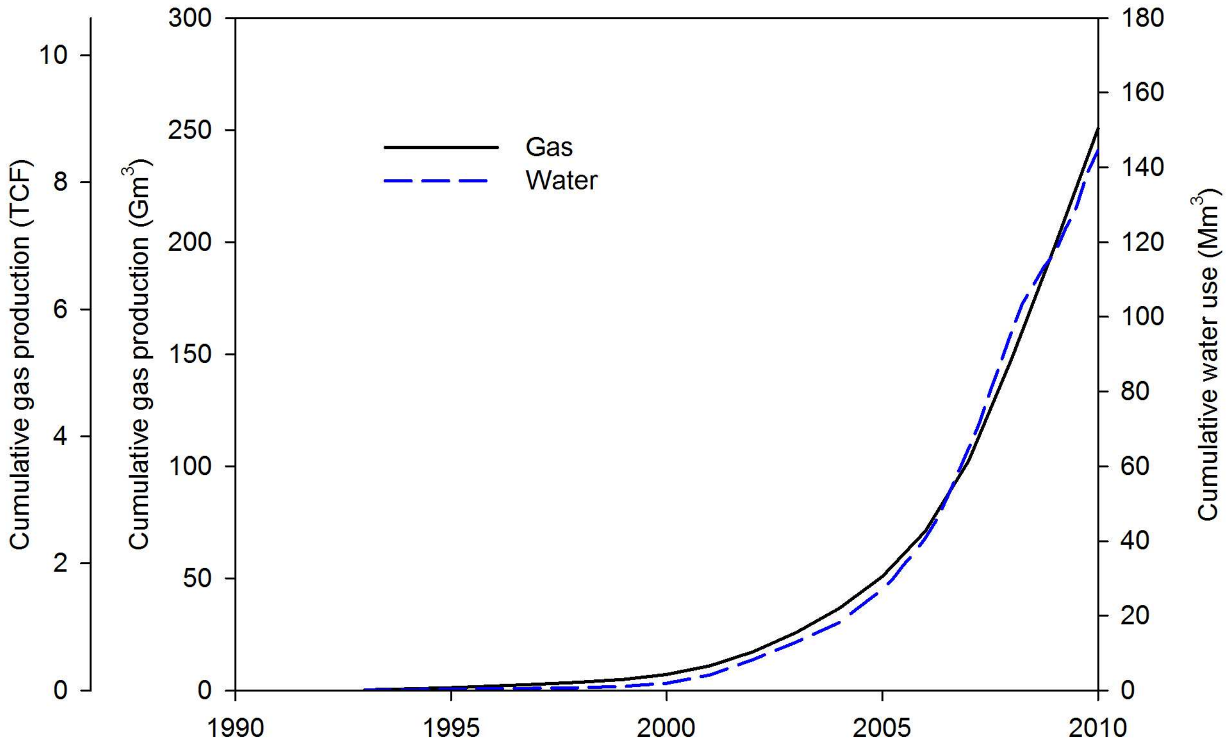

Figure S 2. Cumulative gas production and water use track each other ll in the development / extension phase of the Barnett Shale play.

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 $\leqslant$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.

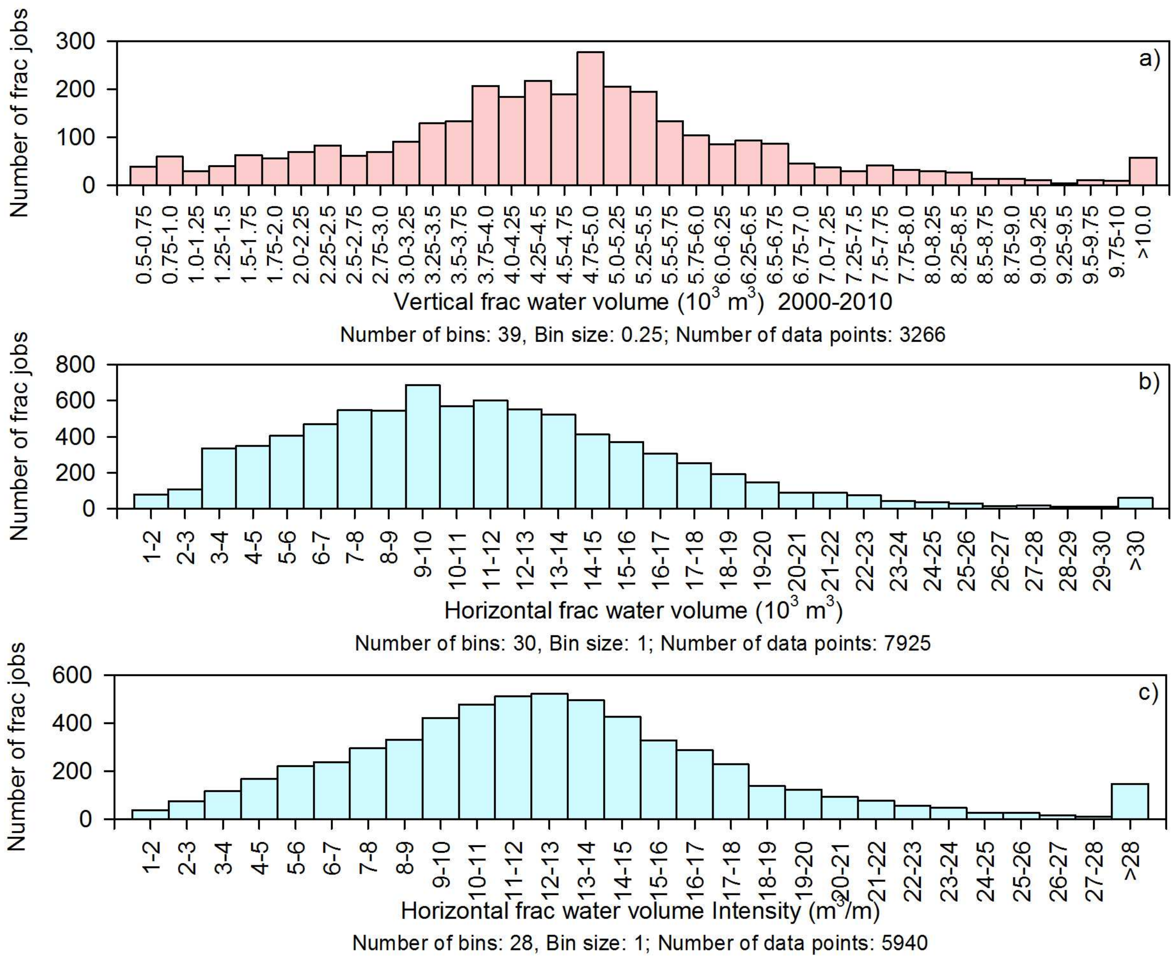

Figure S 3. Histograms of frac water volume for vertical wells, horizontal wells, and water intensity for the 2000–2010 period in the Barnett Shale play (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

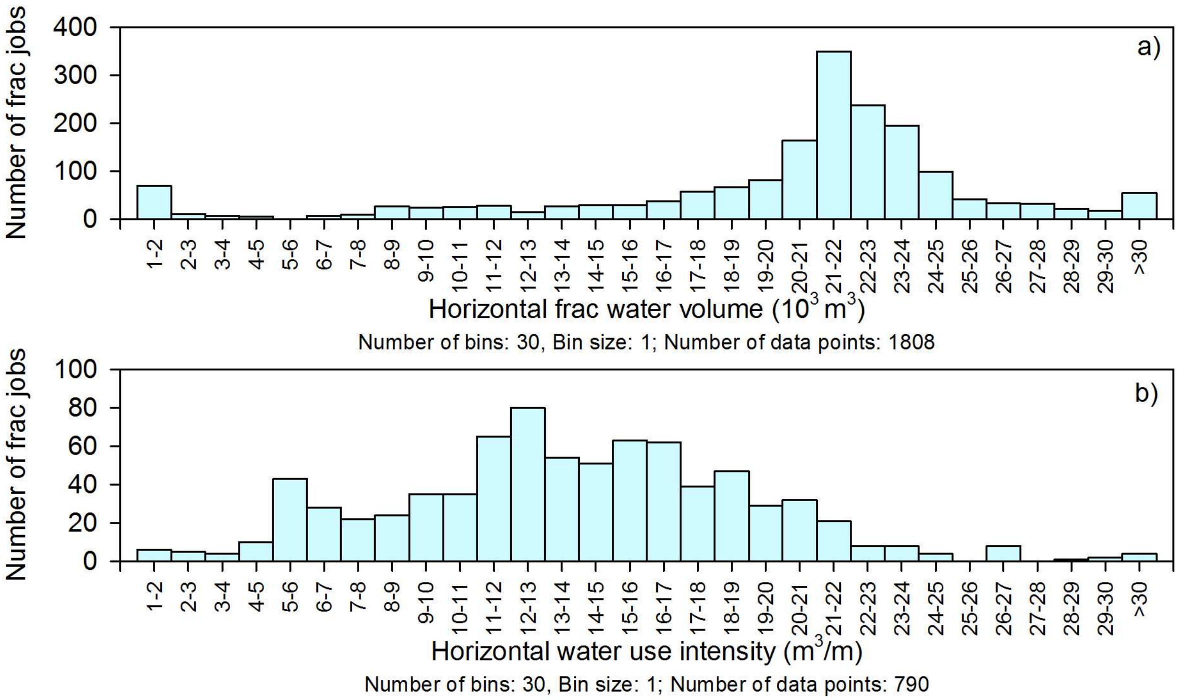

Figure S 4. Histograms of horizontal well frac water volume and water intensity in the Haynesville Shale play (Texas and Louisiana) (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

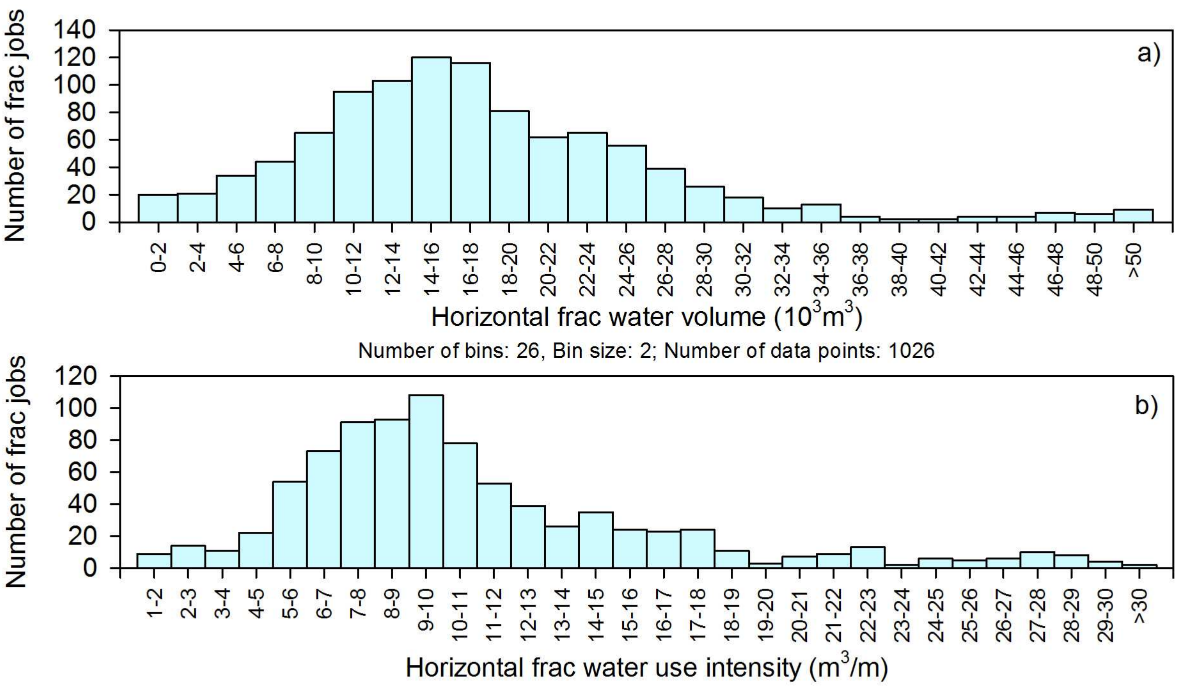

Figure S 5. Histograms of horizontal well frac water volume and water intensity in the Eagle Ford Shale play (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft).

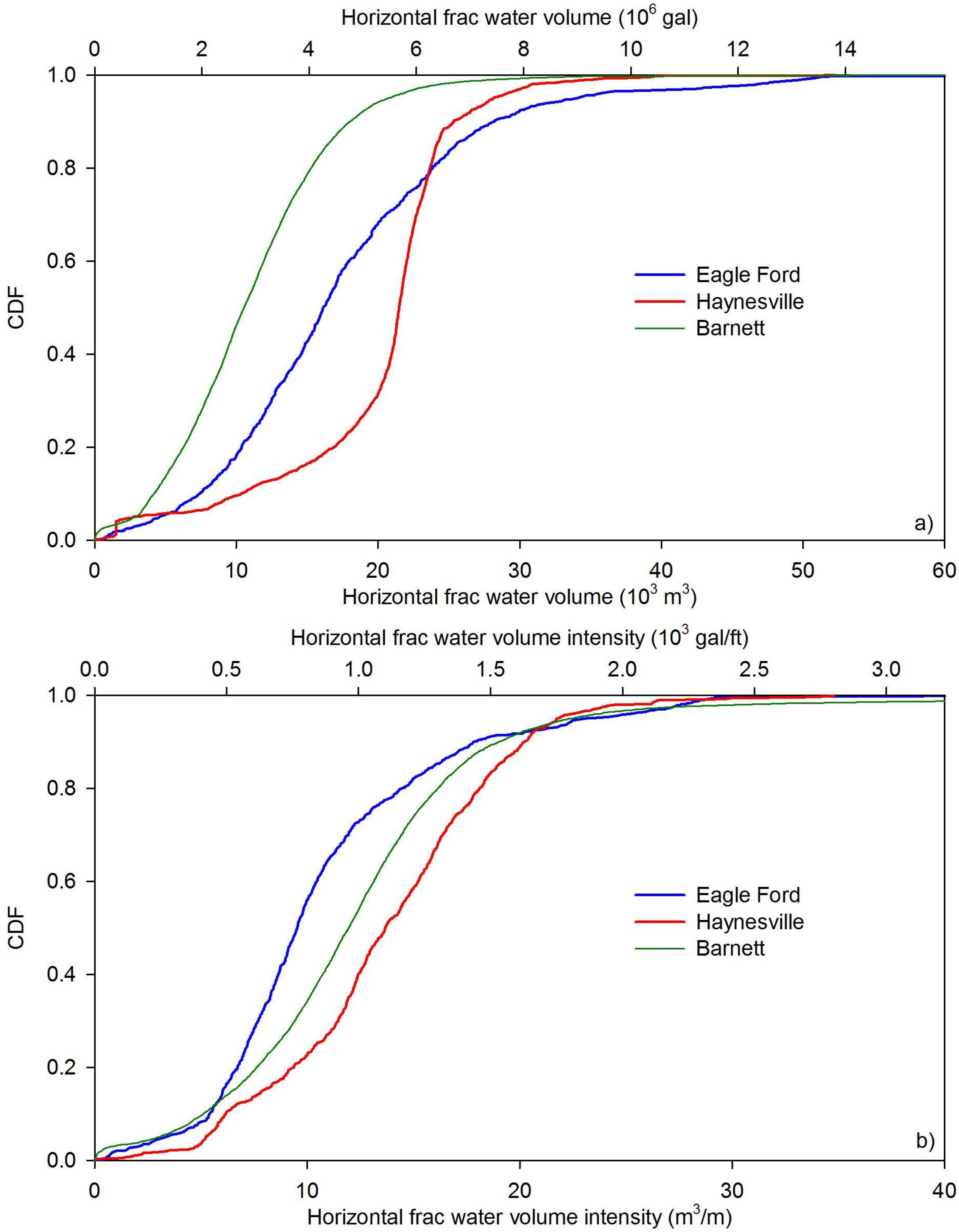

Figure S 6. Data-based cumulative distribution function for horizontal well frac water volume and water intensity in the Barnett, Haynesville (TX+LA), and Eagle Ford Shale plays (1000 m^3 = 0.26 Mgal; 10 m^3/m = 805 gal/ft)

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

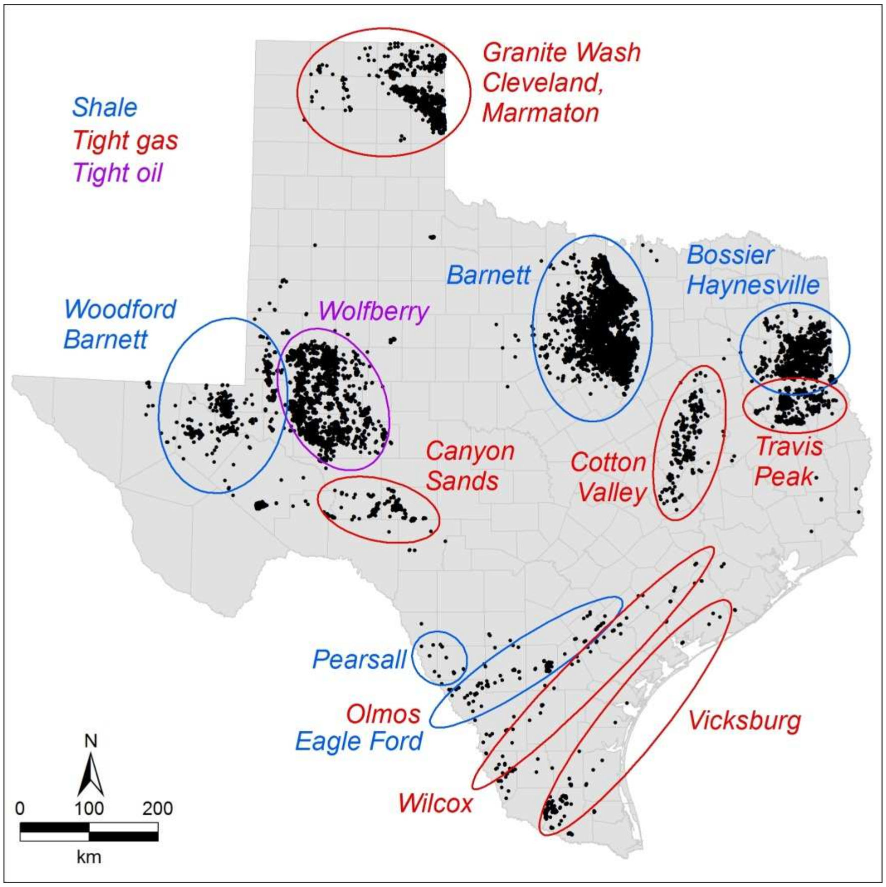

Figure S 7. Map showing locations of all frac jobs in the 2005–2009 time span in Texas. Approximately 23,500 wells are shown.

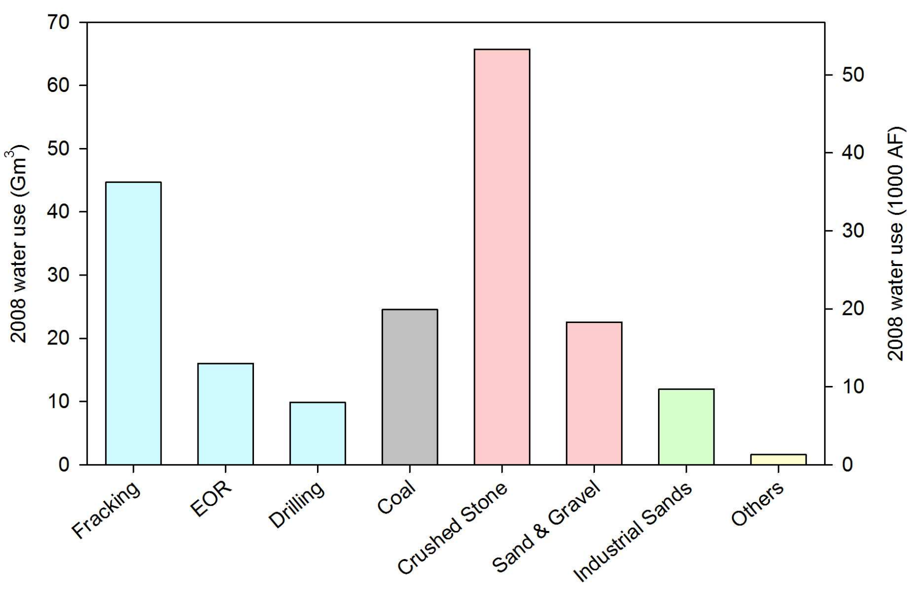

Figure S 8. Summary of 2008 water use by mining category in Texas (all sources). All categories are consumptive except some coal operations withdrawing water from aquifers (that is, consumptive for the aquifers) and redirecting them to surface water bodies.

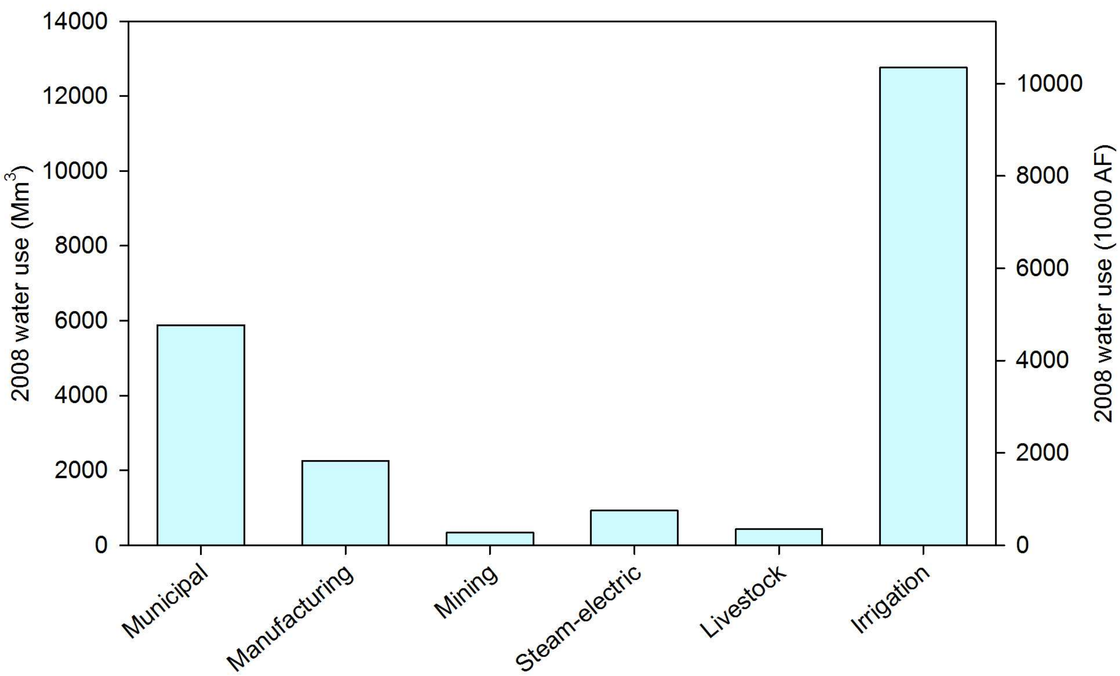

Figure S 9. Summary of 2008 overall water use in Texas. Irrigation, livestock, steam electric, and mining are overall consumptive. Water use for municipal and manufacturing is only partly consumptive because some of the water is returned to surface water bodies (lakes, rivers) and could be used again.

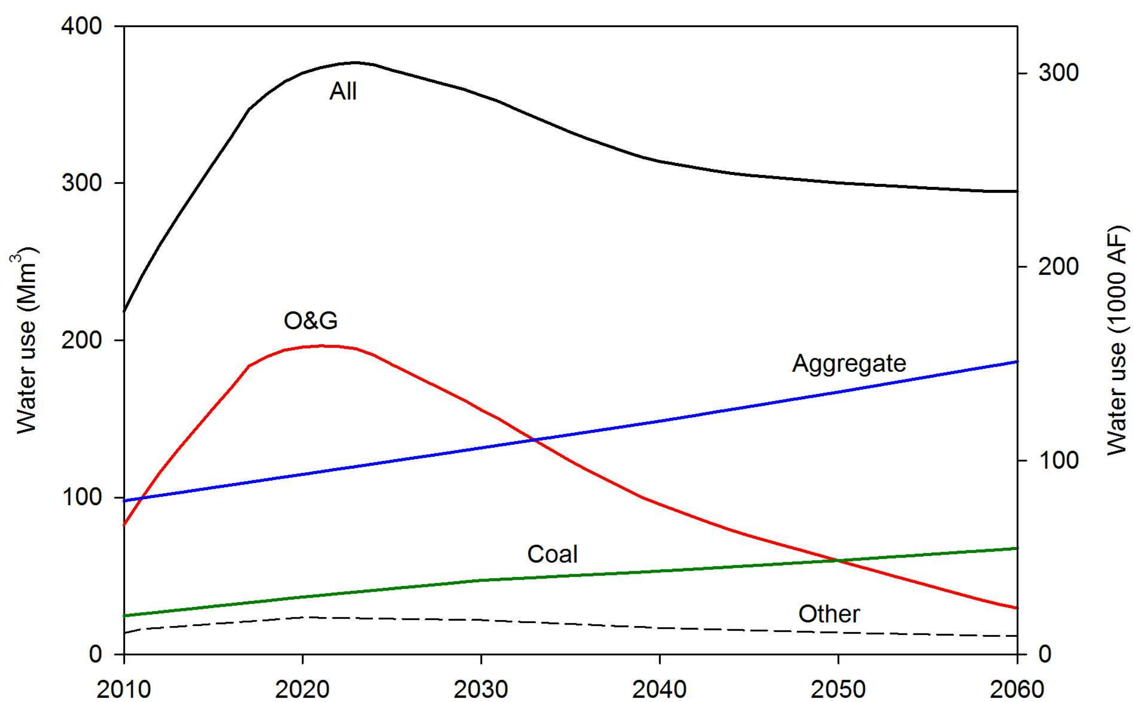

Figure S 10. Summary of 2010–2060 projected net water use in the mining industry segment (some coal water use can be considered as non- consumptive).

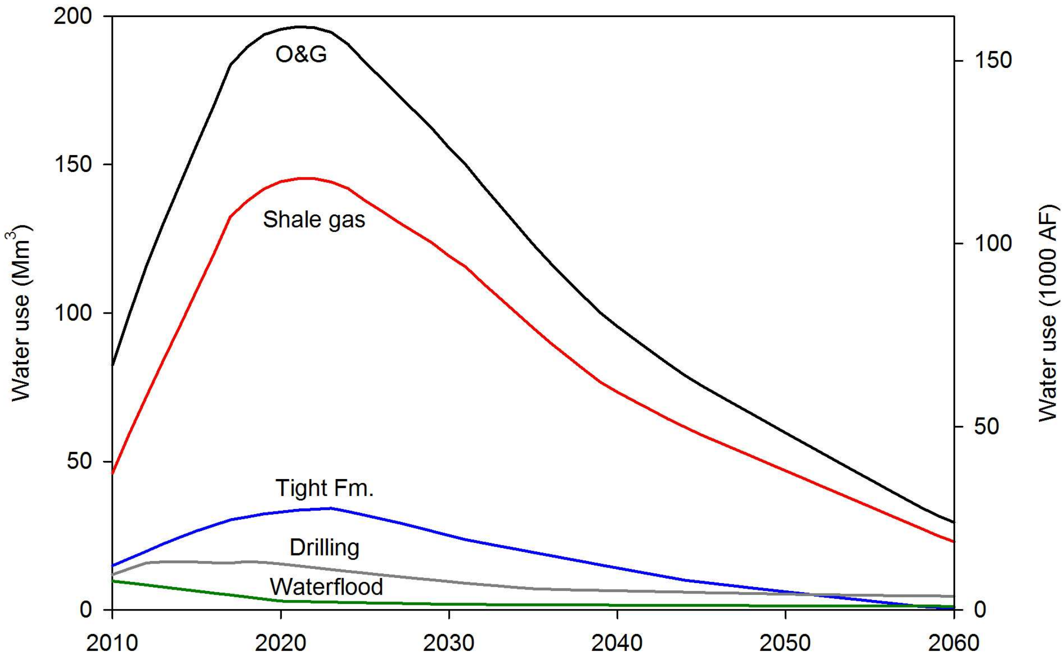

Figure S 11. Summary of 2010–2060 projected net water use in the oil and gas segment.

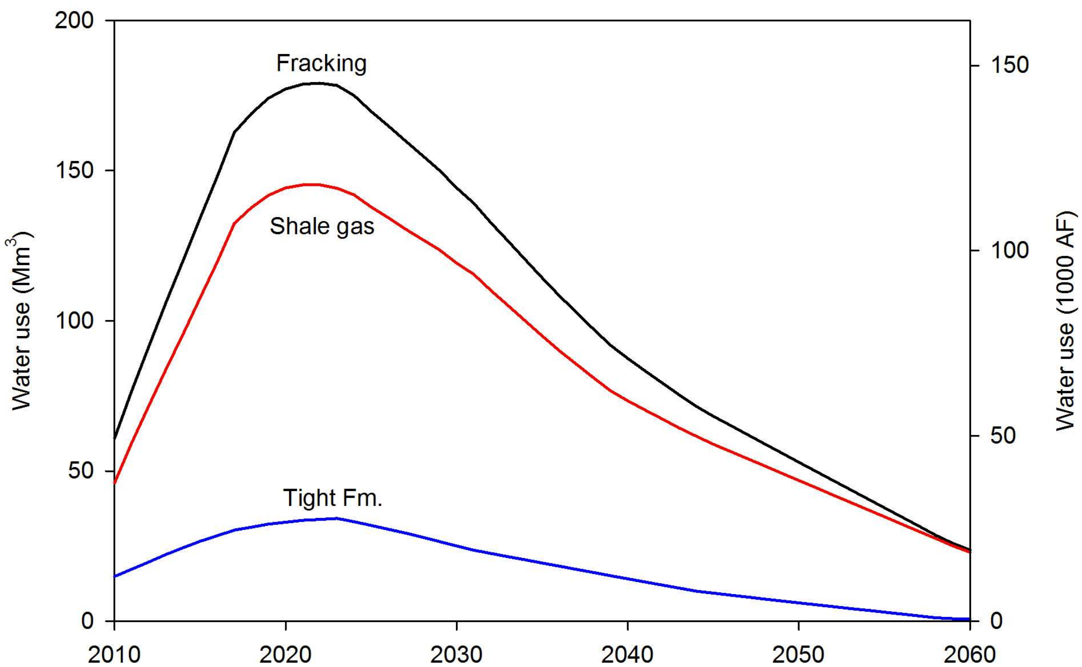

Figure S 12. Summary of 2010–2060 projected fracking shale-gas and tight-formation net water use.

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

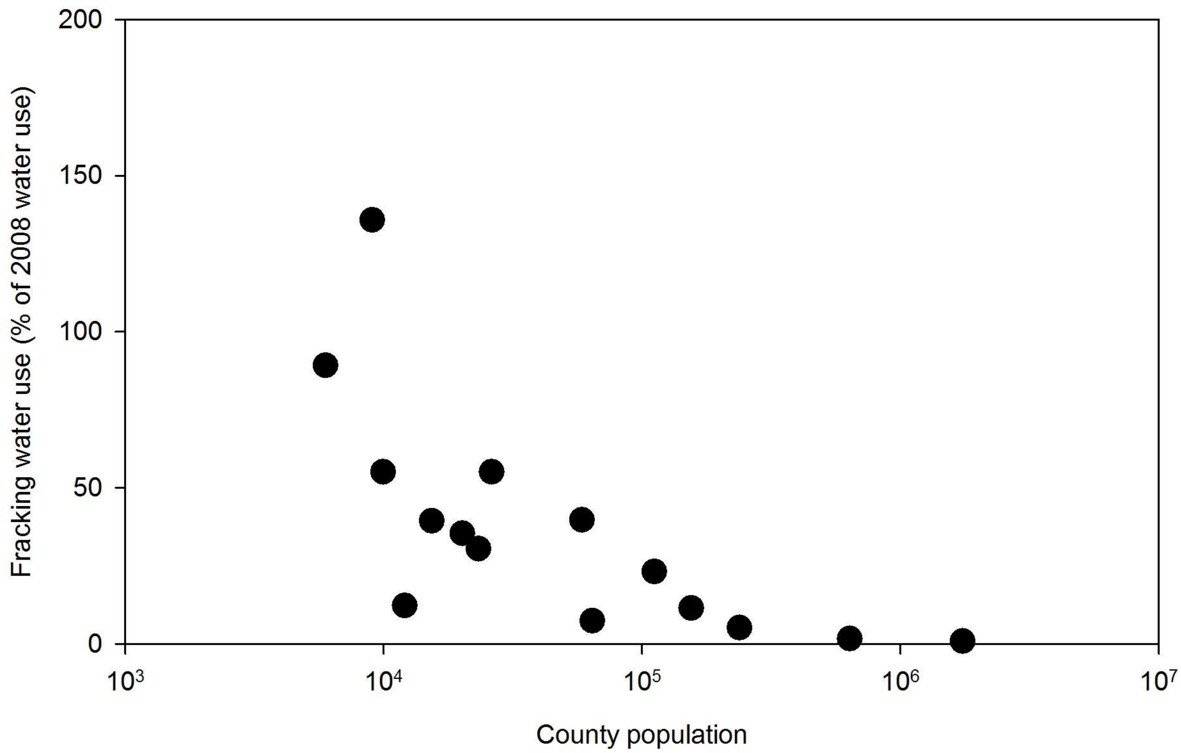

Figure S 13. Fraction of county-level highest annual fracking net water use relative to a 2008 total-water-use baseline in the same county. Counties with low populations should experience a large relative increase in water use because of a low baseline, whereas counties with a large population show a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

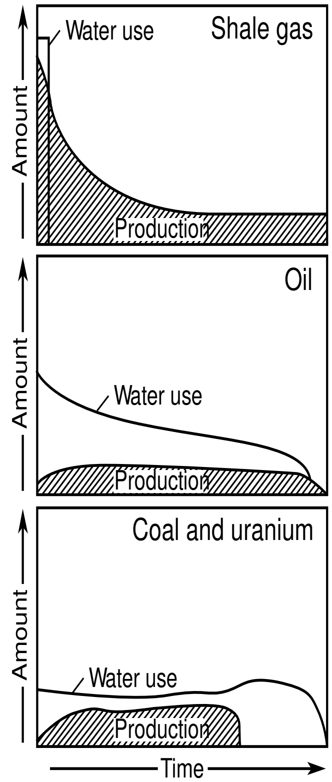

Figure S 14. Illustration of net water-use (water consumption) patterns in various mining industries in Texas. Time frame varies from years to decades. The relative size of the production and water-use curves and the relative size of the three water use curves are only indicative and should not be quantitatively 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:

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

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

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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