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Supplementary Information for

Water use in the US energy system:

A national assessment and unit process inventory

of water consumption and withdrawals

Emily Grubert[1*], Kelly T. Sanders[b]

This PDF file includes:

Supplementary Text (184 pages)
Tables S1 to S15

Other supplementary information for this manuscript includes the following:

Data File S1 as Excel Workbook: Water Use in the US Energy System

[1]Emmett Interdisciplinary Program in Environment and Resources, Stanford University, Y2E2 Suite 226, 473 Via Ortega, Stanford, CA 94305.
[b]Sonny Astani Department of Civil and Environmental Engineering, University of Southern California, Kaprielian Hall, Room 200b, 3620 S. Vermont Avenue, Los Angeles, CA 90089.
[*]Correspondence to: Emily Grubert, gruberte@berkeley.edu.

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Executive Summary of the Supplementary Information

This detailed Supplementary Information (SI) text supplements the main paper and Data File S1 with detailed descriptions of water withdrawn and consumed for seventeen fuel cycles in the United States, covering 99.4% of commercial primary energy (excluding food and feed) consumed in 2014. (The remaining 0.6% is mostly heat from renewable resources, including wood, solar, and geothermal, that is not likely to have water use impacts.) The seventeen fuel cycles include eleven fuels, with internal differentiation for several fuels where water use or application profiles are sufficiently distinct that analysts are likely to benefit from higher resolution. Specifically, data are differentiated for conventional and unconventional oil and natural gas resources; ethanol and biodiesel liquid biofuels; subbituminous, bituminous, and lignite coal; and photovoltaic and thermal solar resources.

The SI text following this summary presents methods and results organized by resource, with the exception that the method for estimating water withdrawal and consumption for thermoelectric power plants (excluding geothermal and solar thermal facilities) is described in its own section. In addition to this text, the SI includes an Excel file (Data File S1) with quantitative detail on the results presented in this work. The Excel file includes:

- Water withdrawal and consumption values, both absolute and per GJ of energy delivered to the consumer, by life cycle stage for all seventeen fuel cycles analyzed across twelve water source/quality categories;
- Resource-specific summaries of water withdrawal and consumption by individual process analyzed within each life cycle stage, including absolute values, intensity per GJ involved in the process, and intensity per GJ delivered to the consumer;
- Conversion factors and constants used in this work; and

- Total GJ involved in each life cycle stage by resource for the US in 2014.

Several resource- and system-relevant conclusions stand out, which are summarized very briefly in this section.

- Once-through cooling at steam cycle power plants dominates water withdrawals for the energy system.
    - It is well known that power plant cooling systems rival only agriculture in demand for US water withdrawals.
    - Our research adds resolution and shows that this major water withdrawal is specifically for once-through cooling systems at steam cycle-based power plants, which account for over 75% of total power plant water withdrawals and over 70% of total energy-related water withdrawals. These systems generate about 25% of the US' electricity (as of 2014), with fewer than 1,000 units at about 300 sites (EIA 2015)[1].
- Both technological and policy changes contribute to changing water intensity in the energy sector.
    - Based on available data and our analysis, oil extraction from shale resources using hydraulic fracturing is less water intensive than oil extraction using enhanced oil recovery (EOR) techniques like water flooding.
    - Requirements to add flue gas desulfurization (FGD) systems at coal-fired power plants reduce water withdrawals (but increase consumption) at coal-fired power plants overall. The reason is that FGDs act as closed-loop pre-cooling systems for flue gases, which reduces the cooling need and thus

withdrawals for the main cooling system. At plants with once-through cooling, this effect can be large.

  - Wind and solar photovoltaic fuel cycles are much less water intensive than the existing energy system.

- Energy-related water consumption and withdrawals are both mostly freshwater. Consumption is primarily groundwater and related to the energy production life cycle stage (largely as irrigation for ethanol crop production and produced water from wells and mines). By contrast, withdrawals are primarily surface water and related to the energy conversion life cycle stage (largely as cooling water for steam cycle power plants with once-through cooling systems).

Standard Assumptions

Sources for this effort were sought in the following order of preference:

1. Raw, centrally reported empirical data for water consumption, withdrawal, source, and/or quality (e.g., through an Energy Information Administration publication);
2. Peer-reviewed literature using recently (<10 years) collected datasets;
3. Non-peer-reviewed literature using recently (<10 years) collected datasets;
4. Personal communication with operators;
5. Recent official estimates for water consumption, withdrawal, source, and/or quality (e.g., through an Environmental Impact Statement document projecting water use for a particular project or project category);
6. Calculated values based on thermodynamic, chemical, or other physical relationships (e.g., evaporation, chemical scrubbing);

7. Older data (≥10 years) in the same preference order as the newer data.

A note on the issue of seeking information in the peer-reviewed literature is that data on water intensity of energy systems are heavily re-cited, so it is critical to evaluate the source data and, often, to follow references to their origin. In particular, many modern publications rely heavily on Gleick's 1993 compendium of water intensity of energy systems[2] (often via major re-citations of that work in works including Gleick 1994, DOE 2006, Mielke et al. 2010, and Meldrum et al. 2013)[3–6]. The 1993 compendium is itself largely based on a DOE technology characterization compendium published in 1980, which draws on older data that are often single-plant examples or forecasts of water intensity (DOE 1980)[7]. Thus, values in even very recent publications citing other recent publications are in some cases 70-year-old estimates rather than an empirical reflection of the water-energy nexus as it currently exists in the United States.

<u>Limitations</u>

As noted in the main text, the known limitation with the greatest influence on the overall findings in this work is that the total volume of water withdrawn and consumed in the United States in 2014 is not precisely known. To add confidence that our estimate is approximately correct, this section describes how these totals were selected.

Total US water consumption in 2014 is estimated using two approaches. The first approach uses data from the most recent USGS estimate of both water consumption and water withdrawals, a 1998 estimate of 1995 conditions (Solley et al. 1998)[8]. That report cites 1995 withdrawals of 402 billion gallons of water per day (bgd), of which 341 bgd were fresh. Freshwater consumption for 1995 was estimated at 100 bgd, or about 30% of freshwater withdrawals. Assuming that 30% of water withdrawals of any quality are consumed, extrapolating to the most recent available national withdrawal data (a 2014 estimate for 2010, Maupin et al. 2014)[9] suggests 2010 water consumption of about 1.4×10^{11} m^3 (and freshwater consumption of about 1.2×10^{11} m^3). Further assuming that national water withdrawals and consumption are very similar for 2010 and 2014, this approach suggests that water consumed for energy in 2014 accounts for 11% of total water consumption and 11% of freshwater consumption.

A second approach to estimating the proportion of US water consumption attributable to the energy system uses the same 1998 estimate of 1995 conditions to note that an estimated 80% of water was consumed for irrigation (Solley et al. 1998)[8]. The US Department of Agriculture (USDA) also notes 80% of US water consumption is for irrigation, though the source for this claim is not listed (USDA 2017)[10]. USDA estimates 2013 consumptive water use for irrigation at 89 million acre feet, or 1.1×10^{11} m^3 (Set 1, Table 1-15d, USDA 2017)[11]. This work estimates energy-related 2014 water consumption at 1.62×10^{10} m^3 (fresh consumption of 1.30×10^{10}). Assuming irrigation accounts for 80% of US consumptive total water use, total 2013 water consumption is estimated at 1.4×10^{11} m^3. In this case, energy-related water consumption is estimated at 12% of total water consumption. By contrast, assuming irrigation accounts for 80% of US consumptive freshwater use, 2013 freshwater consumption is estimated at 1.4×10^{11} m^3 and 2013 total water consumption is estimated at 1.6×10^{11} m^3, assuming consumption to withdrawal ratios are the same for fresh and nonfreshwater sources and assuming withdrawals match those in Maupin et al. (2014)[9]. In this case, energy-related freshwater consumption accounts for 9.5% of US freshwater consumption, and energy-related total water consumption accounts for 10.2% of US total water consumption. Despite limitations on data, including inconsistent base years and lack of clarity on where numbers are measured versus estimated, an overall estimate that the US energy system accounts for about 10% of both US freshwater consumption and US total water consumption appears robust. Again, caution is advised, particularly as changes to practices in high-withdrawal systems like irrigation (for example, high efficiency irrigation) and thermoelectric power plant cooling (for example, different proportions of once-through versus closed-loop cooling systems) between 1995 and 2014 might affect the relationship between withdrawals and consumption.

Total US water withdrawal in 2014 is assumed to be the same as the USGS-estimated water withdrawal for 2010, the most recent available at the time of this writing, at 355 billion gallons per day, 86% of which is fresh (Maupin et al. 2014)[9]. Converting to SI, this is 4.9×10^{11} m^3/year total water withdrawals, and 4.2×10^{11} m^3/year freshwater withdrawals. Note that this estimate excludes withdrawals from natural channels for hydropower, which we estimate at 2×10^{13} m^3/year. This work's estimates of 2.2×10^{11} m^3/year total water withdrawals and 1.8×10^{11} m^3/year freshwater withdrawals correspond to the proportional estimate of 45% of water withdrawn for the energy system and 42% of freshwater withdrawn for the energy system. We urge extreme caution, however, given both that 2014 withdrawal data are not available and that some of the major nonthermoelectric water withdrawals addressed in this research are not included in the USGS numbers. Specifically, water extracted from mines and wells for resource extraction is not reported in Maupin et al. (2014)[9] unless it is beneficially reused. This exclusion means that dewatering volumes and produced water volumes of about 5.4×10^9 m^3—about 1% of estimated 2010 total US water withdrawals—are included in the numerator (this study's estimate of energy-related water withdrawals) but not the denominator. The effect on the proportional estimate is small (yielding estimates of 44.7% vs. 44.2% of withdrawals) and thus, for clarity, no adjustment is made to the 2010 estimate.

Other limitations that apply to this study include reliance on nonprimary sources of data and the decision to limit the scope of research to 2014 in the United States. Use of nonprimary sources means that source data are not all collected with the same goal, and adjustments made in this work to standardize characteristics like base year, water quality and source definitions, and others introduce further uncertainty. The use of 2014 as a baseline means that continued changes in the energy industry are not captured, and dynamism associated with precipitation patterns, economic shifts, and others is also not captured. Restriction to the United States means that the use of these data might not be appropriate in other regions, particularly for estimates associated with geologic rather than thermodynamic drivers, such as mine dewatering volumes versus power plant cooling water use.

Definitions Used in this Research

Water

- water use
    - Unless otherwise specified, the quantity of water removed from the environment to meet the operational needs of the process under analysis. "Water use" does not refer to quality changes or to water needs met directly by rainwater or a living plant's use of groundwater. Water embodied in the support infrastructure for the energy system, like concrete, steel, process chemicals, etc., is not included.
- water consumption
    - Removal of water from its proximate originating source (e.g., a stream or an aquifer) without directly returning it. Consumptive uses include evaporation, incorporation, and discharge to a nonoriginating body (including groundwater that is discharged at the surface). Contamination is not considered to be consumptive in this research.
- water withdrawal
    - Removal of water from its proximate originating source (e.g., a stream or an aquifer) whether or not it is returned.
        - Note that definitions of "withdrawal" (and "consumption") are inconsistent in the literature. For example, classifying flows for hydropower or produced water from fossil energy resource deposits as withdrawals, as we do in this work, is not universal. However, we see no compelling physical argument that transferring water to a pipe

for hydropower is distinct from transferring water to a pipe for power plant cooling or that removing groundwater, even deep groundwater, from an energy resource reservoir and disposing it to the surface is distinct from a municipality pumping water, potentially fossil water, from an aquifer and eventually disposing it to the surface. The primary distinctions are issues of quality (e.g., thermal pollution or salinity), not of mass transfer. Similarly, definitions of withdrawal and consumption that depend on whether transfers are discretionary or whether water is put to beneficial use easily lead to unequal treatment of physically similar activities.

- water discharge
    - Return of water to the environment in liquid form, whether or not it is returned to the water's proximate originating source.
- return flow
    - Return of water to its proximate originating source. Equivalent to withdrawal less consumption.
- water from combustion
    - Water produced from hydrogen and oxygen during combustion. This is the only water considered to be "produced" in this work. Combustion water is reported separately (i.e., not included in withdrawal and consumption estimates unless explicitly noted) as its fate (i.e., source and quality upon incorporation to the hydrologic system) is unknown.

- freshwater
    - Water with less than 1,000 milligrams per liter (mg/L) total dissolved solids (TDS).
- brackish water
    - Water with TDS between 1,000 and 3,000 mg/L.
- saline water
    - Water with TDS between 3,000 and 50,000 mg/L, including all seawater.
- not RO treatable water
    - Water with TDS exceeding about 50,000 mg/L, making it too salty for membrane-based desalination, notably reverse osmosis (RO).
- surface water
    - Water with its most recent origin above the earth's surface, for example in a lake, river, or ocean.
- groundwater
    - Water with its most recent origin below the earth's surface in an aquifer.
- reuse
    - Water with its most recent origin at the end of an external anthropogenic process, for example municipal wastewater. Same-facility reuse is not considered reuse for the purposes of this work.

Energy

- 2014 US energy system
  - The network of processes supporting production, processing, transportation, conversion, and waste disposal for commercial fuels occuring within United States borders in calendar year 2014. That is, US refining of imported fuels is included, but extraction of those imported fuels outside the US is not. Similarly, US extraction of exported fuels is included, but downstream processing of those exported fuels outside the US is not. Notably, this work excludes food and feed.
- delivered energy
  - Used interchangeably with "energy delivered to consumer." The amount of energy delivered to the consumer as an energy currency, with losses incorporated from upstream but not downstream stages. Most significantly, a unit of delivered electricity energy is substantially more removed from primary energy than a unit of delivered liquid transportation fuel energy, as the major energy losses occur upstream of the consumer for electricity (i.e., in a power plant) but downstream of the consumer for liquid transportation fuels (i.e., in a vehicle engine). The use of intensity factors based on units of delivered energy is an attempt to make intensities more easily comparable across fuels.
- production
  - Processes associated with extraction or capture of a resource. For example, mining. Processes associated with making fuel resources available for use

(e.g., reservoir storage for hydropower or solar photovoltaic panel cleaning) are included in the production stage.

- processing
    - Processes associated with improving a resource's usability in the energy system that are not primarily intended to extract work from the resource. For example, contaminant removal and fuel fabrication.
- transportation
    - Processes associated with moving a fuel resource, mainly prior to conversion. For example, pipeline use. Electric power lines are not explicitly considered but are assumed to have negligible direct water use.
- conversion
    - Processes associated with the production of an energy currency (secondary energy) from an energy resource (primary energy). In this work, this category includes, almost exclusively, power generation and liquid fuel refining.
- post-conversion
    - Processes associated with resource management after conversion processes, notably excluding processes associated with ultimate use. In this work, this category includes, almost exclusively, waste management.

Oil

The oil fuel cycle withdraws and consumes water for extraction (including enhanced oil recovery, hydraulic fracturing, and produced water), pipeline transportation, crude processing and refining, and in power plants. Notes on oil storage and end uses are also included. Conversion for transportation uses, the dominant end use of oil, does not generally use water. Burning oil releases water as a combustion byproduct.

This work estimates that the US oil system consumes 2.1×10^{-2} m^3/GJ delivered energy of freshwater (9.2×10^{-2} m^3/GJ total water) in the US through these mechanisms, noting that all domestic water use is considered here, regardless of the origin of the oil. That is, water used to refine imported crude in the United States is counted, while water used to produce oil outside the US that is later used in the US is not. Note also that the large increase in unconventional oil production from tight formations like shale starting around 2010 means that data vintage for oil extraction is highly relevant. US oil withdraws 6.8×10^{-2} m^3/delivered GJ of freshwater and 2.4×10^{-1} m^3/delivered GJ total. Many of the steps in the oil fuel cycle are robust to relatively low water quality. Note that states control a significant portion of the regulatory process for oil and natural gas, so the data sets used in this work are generally either state-level analyses or aggregations thereof.

Extraction

Data on water used for oil and natural gas extraction are relatively plentiful, particularly when compared to data for other energy extraction processes. This data abundance is likely due to significant changes in the oil and natural gas industries in the last decade that have put water use in the spotlight, particularly the rise of multistage high-volume hydraulic fracturing applied to horizontal wells (HF), a completion technique commonly referred to as hydraulic fracturing, fracking, or fracing. Multiple recent studies of water use for oil extraction (e.g., Ali and Kumar 2017, Kondash and Vengosh 2015, Murray 2013, Scanlon et al. 2014, Tiedeman et al. 2016)[12–16] have been performed. Continued interest in water use for oil and natural gas extraction, particularly for unconventional resources like shale oil and shale gas, is reflected in United States Geological Survey (USGS) efforts through the Water Availability and Use Science Program (WAUSP) to gather, model, and publish higher resolution national data than are currently available through the five-year estimates (Carter et al. 2016)[17]. Conventions differ on the choice of reporting metric, e.g., water per well, water per length of wellbore, water per field, or others, which can make direct comparison of water intensity on an energy basis somewhat challenging.

In this analysis, drilling water is calculated based on estimated relationships between production and water use (Scanlon et al. 2014)[15] rather than taken from a database of measurements like FracFocus, even though the typical data priority for this work is to rely on measured values first. Here, this choice is because FracFocus is believed to underreport water use, possibly by about 35% (Scanlon et al. 2014)[15]. A likely explanation for the discrepancy is that FracFocus reports water used for HF rather than for all drilling-stage water use.

Drilling

Total US water volumes withdrawn and consumed for drilling and cementing oil wells are estimated based on 2014 estimates based on bore volumes and water requirements for cementing, at about 0.02 vol/vol for conventional oil and 0.04 vol/vol for unconventional oil (Scanlon et al. 2014)[15]. (Note that 0.2 vol/vol is sometimes cited for drilling water requirements for oil production: based on an assessment of underlying data in both Scanlon et al. 2014[15] and Gleick 1993[2], this appears to be a typographical error and should be about 0.02 vol/vol.) The overall US estimate is made by multiplying EIA values for conventional and unconventional 2014 oil production in the United States (EIA 2017, Crude Oil Production[18], and EIA 2015, Drilling Productivity Report[19]) by their respective intensity factors. Given the nature of the drilling process, no water is assumed to be returned to its original source, so withdrawals and consumption are the same. Note that this work uses a volume/volume estimate (which is itself based on a bore volume-based estimate) rather than a direct bore volume-based estimate: the main reason for this choice is that drilling footage is not available through centralized public sources for the target period (EIA 2015, Drilling Productivity Report)[19].

Estimates for water used for drilling are rooted in physical principles, but drilling water source and quality allocations are based on assumptions. First, the volume of recycled water used for drilling is estimated assuming that all oil and natural gas-related produced water used for beneficial reuse is used in drilling (at 0.6% of produced water, Veil 2015)[20], allocated between oil and natural gas wells based on Kondash and Vengosh (2015)[13]. All recycled water is assumed to be saline or not RO treatable (though it might be treated in some manner to remove salts before reuse). The remainder of the drilling water is allocated to groundwater or surface water sources based on the ratio between groundwater and surface water sourcing for hydraulic fracturing water for unconventional wells in the Bakken and Eagle Ford shale plays, accounting for 75% of 2014 unconventional production, at 57% groundwater to 43% surface water. While there is no clear evidence that water sourcing for unconventional wells is similar to that for conventional wells, this assumption is made for simplicity absent evidence otherwise.

All groundwater and surface water used for drilling are assumed to be fresh given a lack of more specific data and a general decision throughout this work to conservatively overestimate the use of freshwater for the energy system. However, evidence from Texas suggests a trend toward increased use of brackish rather than freshwater for oil extraction, with brackish water share as high as 80% for the Permian Basin in 2010 (Scanlon et al. 2014, Supporting Information)[15].

Multistage high volume hydraulic fracturing of horizontal wells

Literature estimates for the water intensity of HF are much more recent than those for many other energy systems. This recency is due in part to the fact that the practice essentially did not exist commercially until about 2010 for oil (EIA 2015, Drilling Productivity Report)[19]. This work takes a production-weighted average based on Chen and Carter (2016)[21], which is in turn based on analysis of data for over 80,000 wells hydraulically fractured in the US between 2008 and 2014, as a best-guess estimate for the total volume of water used for HF. The Chen and Carter (2016)[21] values are used preferentially in this work given their recency and use of an extensive database. Numbers for annual water use for hydraulic fracturing based on Chen and Carter (2016)[21] are derived by multiplying values in that document's Table S2 (wells per state by year) by values in Table S5 (annual average water use per well by state by year). Allocation across surface, ground, and recycled water is based on the 2014 value of 4% for recycled water use in hydraulic fracturing (Chen 2016, pers. comm.) and a surface water to groundwater split based on values from the Eagle Ford Shale in Texas and the Bakken Shale in North Dakota (Nicot et al. 2014, UND EERC 2014)[22,23] which accounted for 75% of total unconventional oil production in 2014 (EIA 2017, Drilling Productivity Report)[24]. Note that re-fracturing was not prevalent in 2014, but future work on water intensity might need to evaluate whether and how re-fracturing influences water use.

Produced water

Like natural gas wells but in contrast to uranium ISL wells or coal mines, oil wells are typically thousands of meters deep. This depth suggests that water resources produced from the formation are often isolated from the active hydrologic cycle (as "fossil water") until they are liberated during oil production activities. Produced water quality ranges from brackish to too saline for treatment by reverse osmosis (Harto and Veil 2011, Otton and Mercier n.d.)[25,26], and almost all produced water is reinjected into the ground for disposal or oilfield operations (Veil 2015)[20]. Despite the name "produced water," this work does not consider this water resource to be a net introduction of water into the system in the way that water formed from combustion of hydrocarbons is. Just as fossil water from aquifers like the Ogallala is withdrawn and consumed for human use rather than "produced," so too is formation water from deep wells. This decision is further supported by the observation that beneficial reuse of produced water outside the oilfield is noted as plausible even in cases with substantial depth or quality barriers (Kang and Jackson 2016, Grubert et al. 2015)[27,28]. Rarely, and usually in locations with high quality produced water, such use is observed (see e.g., Onishi 2014)[29].

The major source of data on produced water for this work is a 2015 analysis of 2012 produced water (Veil 2015)[20]. State-specific reported or estimated water-oil ratios (WORs) are used in conjunction with 2014 oil production volumes by state to estimate 2014 produced water volumes. All produced water is accounted as a groundwater withdrawal, with quality allocated by state based on USGS maps of salinity (Otton and Mercier n.d.)[26]. Produced water is allocated to either unconventional or conventional oil production based on Kondash and Vengosh (2015)[13]. Given the tight nature of many unconventional reservoirs as of 2014, produced water volumes from unconventional reservoirs are considerably lower—both in total and in intensity—than from conventional reservoirs.

Consumptive use is estimated based on Veil (2015, Fig ES-2)[20], assuming the ultimate fate of produced waters was constant between 2012 and 2014. Roughly 55% of produced water from oil and natural gas extraction is consumed, i.e. not returned to its original aquifer, through disposal injection (~40% of total), surface discharge (~5% of total), or evaporation, offsite injection, and beneficial reuse (~10% of total). (Almost all offshore produced water—about 80% as of 2012—is discharged into the ocean, with the remainder reinjected, Veil 2015[20].) The remaining 45% is used for enhanced oil recovery, which typically involves injection into the originating formation and is thus considered nonconsumptive. All EOR water is allocated to conventional, i.e. non-tight, oil production. This work makes the simplifying assumption that no natural gas-related produced water is used for EOR (which might not be true in cases of co-produced natural gas in a field using EOR), which implies that 52% of oil-related produced water is consumed and 48% is used for EOR in the originating formation and is thus not consumed. As natural gas-associated produced water is estimated at only 7% of total oil and natural gas-related produced water and only about 20% of natural gas was coproduced with oil in 2014 (EIA 2017, Natural Gas Gross Withdrawals from Oil Wells)[30], the simplifying assumption is not consequential.

Note that data in Veil (2015)[20] include flowback from drilling and completions. While it could be argued that flowback water is being double counted (consumed for drilling, then withdrawn and consumed or not as produced water), this work adopts the stance that the situation is analogous to repeated withdrawals of the same water molecules in other situations and is thus not double counting. However, produced water associated with various resources represents a definitional challenge with respect to withdrawals and consumption, particularly when it is a byproduct of an activity or available for beneficial use downstream (e.g., Grubert et al. 2012, Smith 2016)[31,32]. Volumes and flows associated with moving produced water are relevant to understanding e.g., the energy and financial costs of water handling, and produced water handling meets definitions for withdrawals and consumption of water. However, there is some resistance to allocating produced water consumption to specific industries when the water is not being actively sought out. This work adopts the position that water removal and disposal associated with resource extraction is necessary for that resource extraction, even when it is undesirable, and thus acknowledges but disagrees with the suggestion that produced water should not be counted as withdrawals and consumption. Further, particularly in the oil and natural gas context, being clear about the quality of the water involved (here, usually very saline) supports the intuition that produced water is a less valuable water resource than the freshwater typically discussed with regard to withdrawal and consumption. Finally, this work echoes prior work that data quality on produced water is poor, particularly given that there is no requirement to track volumes in some jurisdictions and that measurements are not always made using reliable tools (Clark and Veil 2009, Veil 2015)[20,33].

Water and Steam Flooding (Secondary and Tertiary Recovery)

Many techniques exist to increase recovery of oil in place, including enhanced oil recovery processes like CO_2 injection and others. For this water-focused work, two processes in particular are relevant to the water balance of oil production: water flooding (or water injection), a secondary recovery process, and steam flooding (or steam injection), a tertiary recovery process. Both techniques involve the injection of water into a producing formation, whether as vapor or liquid. Water flooding increases oil recovery through physical displacement, increasing the pressure of a depleting reservoir by replacing lost produced fluid volume with water. Steam flooding increases oil recovery both by heating the oil in place to decrease its viscosity, thus enabling it to flow more freely, and by physical displacement similar to water flooding (the precise design of the steam flood dictates the relative importance of this physical displacement versus the thermal effects). Given their low permeability, these processes are unusual or nonexistent in tight formations that have recently experienced high growth. That is, reservoirs where multistage high volume hydraulic fracturing is used do not generally also use water and steam flooding, and vice versa (see e.g., Scanlon et al. 2014[15] for a discussion of water use for oil production in unconventional tight formations versus others).

Most water used for water-based enhanced recovery—about 94% (Veil 2015)[20]—is produced water. This produced water has highly variable quality and is sometimes treated before use. This work assumes that produced water used for EOR is being returned to its original source basin and is thus a nonconsumptive use. A definitional question arising here is whether this EOR water should be considered “reuse” or simply subtracted from the volume of produced water consumed through injection into an aquifer other than its source. An argument for categorizing it as reuse is that the application is beneficial and very likely prevents the water from being consumed through disposal, given other management options. Further, it is often tacitly understood that water used in a “reuse” application might be intentionally used somewhat inefficiently because of the secondary benefit of water disposal, which is consistent with the observation that little water that producers need to obtain externally is used for EOR. However, a reuse designation would also necessitate classification of the use as withdrawal or consumption. Since the water is only withdrawn once—during production—and since the water is returned to its original formation, either designation somewhat misrepresents what is physically happening. This problem is considered more severe, and so the produced water used for EOR is not classified as reuse in this work.

The remaining 6% of the water used for EOR is makeup water from other sources. This makeup water is accounted as a consumptive use. Given limited information about the makeup water, it is assumed to be fresh given the need for clean water for practices like steam flooding (Veil 2015)[20]. Makeup water is allocated to groundwater or surface water sources in the same proportion as hydraulic fracturing water, with caution that EOR and HF basins are differently geographically distributed and might have different water access. However, the allocation is close to 50-50, which is the most logical arbitrary allocation. Produced water volumes for EOR are scaled to 2014 based on the proportion of produced water that Veil (2015)[20] reports as used for EOR in 2012. Makeup water volumes are similarly estimated based on the ratio of makeup to produced water used in EOR reported for 2012 (Veil 2015)[20]. EOR water is all allocated to conventional, i.e. non-tight, oil production given the need for reservoir permeability in EOR applications.

Based on experience to date, a major difference in water use for enhanced recovery versus HF is the timing, as water use for HF occurs all at once during well completion while water use for enhanced recovery occurs over time as a field ages. Refracturing could alter this relationship, though it was not widespread as of 2014.

Processing

Field processing of crude oil is sometimes performed to improve quality before the crude reaches a full-scale refinery. For example, crude extracted from bituminous sands in Canada is often treated with hydrogen to increase fluidity, and very sour (sulfurous) crudes are sometimes stripped at sub-refinery scale processing units. Field processing for US crude oil centers on removing undesirable gases, primarily hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Notably, H_2S levels can be higher in waterflooded or steam flooded oil fields because of introduction pathways for sulfur-reducing bacteria (Boman 2013)[34]. Hydrogen sulfide removal from crude, which is distinct from flue gas desulfurization of post-combustion oxidized sulfur compounds from a power plant or refinery stack (SO_x), generally proceeds through a conversion of H_2S to elemental sulfur (S).

While these processes might not technically occur at full-scale refineries, for the purpose of this work of estimating total water use for energy fuel cycles, the water used for field processing is captured below as a refining use. This decision is motivated by the high risk of double counting given that data are unclear about the precise point of use.

Transportation

Pipelines

As of 2014, the US has about 130 thousand miles of pipeline dedicated to transporting oil (67 thousand miles of crude pipelines and 62 thousand miles of refined petroleum product pipelines) (PHMSA 2017)[35]. About 60% of crude oil received at US refineries is transported by pipeline (EIA 2017, Refinery Receipts of Crude Oil by Method of Transportation)[36]. Pipeline transportation represents a minor withdrawal and consumption of freshwater in the US, primarily via hydrostatic testing that involves first washing, then pressurizing a pipeline with water to test its strength. This analysis is similar to the analysis performed for natural gas pipelines (see natural gas section, this document), using PHMSA data on pressure testing intervals, pipeline mileage, and pipeline diameter for crude oil and refined petroleum product pipelines to estimate the total amount of hydrotest water required. Similar cautions about hydrostatic testing not being the only method for strength testing pipelines apply, and pressure tests using product fluid might be more common for oil pipelines. In 2014, about 4.9% of the total petroleum pipeline mileage in the United States was pressure tested, for about a 20-year test interval (PHMSA 2017, Hazardous Liquid Annual Data – 2010 to present)[37]. This proportion is much higher than for natural gas.

Additional water is used during pipeline cleaning operations, for example as a pig (sometimes "backronymed" as pipeline inspection gauge) propellant. This water consumption can range from tens to thousands of gallons (see e.g., Wylde 2011)[38], often as a slug between runs of other fluids. Measured data from hydrostatic tests by Pacific Gas and Electric (PG&E), which only operates natural gas pipelines, is used as a proxy to estimate the volume of this additional water. Based on 2014 data, total water withdrawals for hydrostatic testing are estimated at four times the tested pipeline volume (see the natural gas section for details). This natural gas-based estimate is almost certainly an underestimate of the amount of water used for oil pipelines, particularly since oil pipelines tend to need more frequent cleaning due to e.g., waxy buildups (PPSA n.d.)[39]. The relative contribution of the likely overestimate due to assuming all pressure tests use water versus the underestimate due to higher cleaning needs for petroleum pipelines is unclear. Overall, however, the total volume of water associated with pipelines is small compared with total water use for oil. Consumption is estimated at 0%: the gas pipeline operator PG&E reports consumption for dust control and irrigation (PG&E 2015)[40], which is not considered pipeline-associated consumption, and a liquids pipeline operator (Enbridge) reports essentially no consumptive use (Enbridge 2016)[41].

Ships

Another 30% of US crude oil transportation is by tanker (EIA 2017, Refinery Receipts of Crude Oil by Method of Transportation)[36]. Oil tankers generally carry cargo in only one direction and thus require additional weight during their empty return voyages for safety (NRC 1996)[42]. Ballast mass replacement for cargo is estimated to be between about 40 and 65% of deadweight tonnage (DWT) for oil tankers (ABS 2004)[43]. About 90% of an oil tanker's DWT is available for oil storage (Hamilton 2014)[44], so ballast water is estimated at 47% of tanker-borne oil import tonnage (using the midpoint of 40 and 65% multiplied by 90%). Given refinery receipts of about 1,828 million barrels of oil by tanker in 2014 (EIA 2017, Refinery Receipts of Crude Oil by Method of Transportation)[36] and a conversion of about 0.14 tonnes of oil per barrel, total water ballast requirements for oil are estimated at 121 million m^3 of water, or about 1.1×10^{-2} m^3/ process GJ of crude transported this way. This water is assumed to all be surface seawater. While it could be argued that the ocean is a single originating water body, given concerns about e.g., invasive species being transported to nonnative environments through ballast water (NRC 1996)[42], ballast water is accounted as a consumptive use as it is discharged distant from its origin upon ship reloading.

Other modes

Vessels like tanks used for petroleum transport by rail, truck, and barge also can require hydrostatic testing and cleaning. Associated water use is assumed to be negligible, especially since some test methods favor air pressure tests, though note that wash water is subject to contamination.

Storage

Oil is often stored in tanks, depleted fields, or salt caverns. This work assumes no additional water use for tank and depleted field storage (though water for hydrostatic testing and cleaning is likely required). Though formation water is displaced by oil during storage in depleted fields, this work assumes that the water does not need to be removed. This assumption is supported by the fact that depleted fields previously held oil or natural gas and are usually hydrologically isolated. Storage in salt caverns requires the use of water for solution mining to dissolve the salt.

Salt Caverns

While salt cavern construction requires a relatively large amount of water to dissolve the salt (see e.g., DOE 2006)[4], ongoing direct water withdrawals and consumption for storage are mainly associated with preventing creep, or closure due to salt movement. Major salt cavern storage facilities include the strategic petroleum reserve (SPR), with capacity of 727 million barrels of oil and infrequent removal (DOE 2012)[45], and the Louisiana Offshore Oil Port (LOOP) caverns, with capacity of about 60 million barrels of oil and more frequent cycling (LOOP LLC 2017)[46]. Salt cavern storage capacity for oil is not reported specifically (EIA 2017, Total Stocks)[47], unlike salt cavern storage capacity for natural gas (EIA 2017, Underground Natural

Gas Storage Capacity)[48], so estimates are based on SPR and LOOP capacities. This work assumes no new caverns were mined for oil storage in 2014. As of this writing, a project to develop about 20 million barrels of salt cavern storage is underway (Fairway Energy 2017)[49].

A study of the largest SPR site, Bryan Mound, suggests annual closure of about 0.06% of volumetric capacity (0.14 million barrels of closure out of a total of 226 million barrels of capacity) (Sobolik and Ehgartner 2009)[50]. While this estimate is based on specific salt characteristics that are unlikely to translate directly to all salt storage caverns, it can be used to roughly estimate water use for salt cavern storage. Given a total SPR and LOOP cavern capacity of about 790 million barrels of oil, and assuming annual closure like that observed at Bryan Mound, maintenance solution mining is estimated at about 0.5 million barrels of storage space per year. Assuming approximate water requirements of 50 gallons per mmbtu of oil storage (DOE 2006, p. 60)[4], and assuming energy density of 5.8 mmbtu or 6.1 GJ/bbl oil, this storage space requirement translates to about 1.2×10^{-4} m^3/ process GJ for oil stored as of 2014, or 1.6×10^{-5} m^3/ delivered GJ based on total oil use in the US.

Conversion

Refining

Refineries withdraw and consume freshwater for process steam and cooling to convert crude oil into secondary energy products like gasoline, diesel, and other fuels. One clear trend from the literature is that refinery water intensity has declined dramatically over time. A detailed assessment of US refinery water use in 1955 estimates refinery water consumption at almost 500 gallons per barrel of crude input (Otts 1963)[51]. Based on modern work (Buchan and Arena 2006 as cited in Hwang and Moore 2011, Masanet and Walker 2013, Nacheva 2011, Walker et al.

2013)[52–55], this work finds that refineries consume between 20 and 30 gallons of freshwater per barrel of crude input to process fuel (Table S1; best estimate: 20 gal/bbl input). This volume rises to a total of about 45 to 70 gallons of freshwater per barrel of crude input when the chemical manufacturing that is collocated with fuels refining at many facilities is included, which is consistent with other published estimates of refinery water usage (e.g., Elgowainy et al. 2014, used for GREET)[56]. Elgowainy et al. (2014)[56] report refinery water intensity about twice what this work finds, based on a model of 43 US refineries accounting for 70% of US refining capacity. These large refineries are also more likely to coproduce chemicals. Since chemical manufacturing is not part of a fuel cycle as assessed in this work, water for chemicals is excluded.

Table S1. Estimated refinery water use in 2014

A. Based on process allocation as in Buchan and Arena 2006

Use	Estimated Percent of Consumption	Estimated water consumption based on MECS 2010, gal/bbl	Estimated water consumption based on MECS 2006, gal/bbl
cooling tower makeup	48%	9.25	12.93
boiler feed	20%	3.85	5.39
fire water/construction water	11%	2.12	2.96
water for process units	10%	1.93	2.69
potable water	6%	1.16	1.62
backwash and rinse	5%	0.96	1.35
	Total, Fuel Only	19.27	26.94
	Total, Fuel and Chemicals	44.87	62.72

Sources: Process-based estimates: Buchan and Arena 2006; MECS 2010: Walker et al. 2013; MECS 2006: Masanet and Walker 2013[52,53,55]

B. Based on process allocation as in Nacheva 2011

Use	Estimated Percent of Consumption	Estimated water consumption based on MECS 2010, gal/bbl	Estimated water consumption based on MECS 2006, gal/bbl
cooling tower makeup	56%	11.36	15.88
water for process units	19%	3.85	5.39
boiler feed	16%	3.25	4.54
other	9%	1.83	2.55
	Total, Fuel Only	20.28	28.36

Total, Fuel and Chemicals	47.23	66.02

Sources: Process-based estimates: Nacheva 2011; MECS 2010: Walker et al. 2013; MECS 2006: Masanet and Walker 2013[53–55]

Withdrawals are estimated at about 1.5 times consumption (Scown et al. 2011)[57] for a best estimate of 30 gallons of water withdrawn per barrel of input. As noted above, many US refineries are producers of both transportation fuels (which are in the scope of this work) and nonenergy chemicals (which are not), and so determining water use factors for refineries requires allocation between the fuel and nonfuel products of the complex. Table S1 shows estimates based on reporting categories from Manufacturing Energy Consumption Survey (MECS) 2006 and 2010, which separate water use for chemicals and thus provide a strategy for estimating the fuel-only water use at refineries.

An additional strategy for determining a reasonable allocation is to investigate refineries that do not have associated chemicals production. This work uses a Californian refinery to check the MECS-based estimate for reasonableness. Since fuel quality standards in California are different from those in the rest of the US, transportation fuels for the California market are generally refined in fuel-only refineries in California. While many of the Californian refineries are coastal, freshwater use appears to be more typical than seawater use due to regulatory limits on the use and heating of seawater, in addition to corrosion and scale concerns (pers. comm, 2015). At one California fuel-only refinery that uses higher-than-typical amounts of air cooling, withdrawals are estimated at 20-30 gallons of water per barrel of processed crude, of which 15-20 gallons is for cooling and 10-15 gallons is for steam. About half of the cooling water (8-10 gallons) and all the steam water (10-15 gallons) is consumed, for a total of about 18-25 gallons of consumptive freshwater use per barrel of processed crude (pers. comm, 2015). This estimate for water consumption at a fuel-only refinery is consistent with the national MECS-based average. The withdrawal-to-consumption ratio of about 1.2 is lower than the estimated average, an expected result given California’s relatively strict limitations on once-through cooling.

Notably, the lower end estimates in Table S1 are based on MECS 2010 data, while the higher estimates are based on MECS 2006. This implies that the downward trend in water consumption at refineries continues. If this detected trend is real, there is a strong argument to be extremely cautious about data age when evaluating water use at refineries. For example, Gleick estimates 40-105 gallons of freshwater consumption per barrel of oil equivalent in traditional refineries and 97-194 gal/boe for refineries with reforming and hydrogenation, which is significantly higher than seen in modern refineries (1994)[3]. Other publications, including Wu et al. (2011)[58] and EPA (2017)[59], also note relatively high water consumption in part based on these older datasets.

Power generation

Oil is primarily used for transportation, but some oil products are burned in power plants. Notably, power plant cooling is the second-largest water withdrawal (after produced water) for oil on a delivered energy basis, despite the relatively small fraction of oil used in power plants. Please see the section on Thermoelectric Power Generation for details on the calculation of water use at oil-fired power plants.

Direct use

The direct use of oil products in non-steam generating capacities, including in vehicles like cars, trains, and airplanes, is assumed to require no direct water consumption or withdrawal, as most of these processes are air-cooled. The major exception is for ships, which withdraw water from the oceans or other water bodies they ride on. Seawater or other raw water is often used as an indirect coolant, with fresh or distilled water used in a cooling loop that directly contacts sensitive components (Anish 2016)[60]. Ships need to be consistently cooled during transit. Challenges associated with e.g., defining when the cooling occurs in US waters versus non-US waters means that no estimate for ship cooling water is made in this work. Note that some environmental impact statements provide information on ship cooling needs. For example, the Oregon LNG DEIS includes per-hour cooling needs for various ship sizes and configurations (FERC 2015, 4-50)[61].

Combustion

As a hydrocarbon, oil releases water alongside CO_2 when it is combusted. On average, combusting oil produces about 0.029 m^3 of fresh water vapor/delivered GJ. This estimate assumes an average H/C ratio of two, as petroleum can be idealized as chains of CH_2 units. This combustion water is accounted for as produced surface water, which may fall as rain and either remain fresh or become part of the ocean. For simplicity, this analysis accounts for the water as fresh, as it is fresh when produced.

<u>Direct waste handling</u>

Aside from wastes handled at petroleum refineries, there is little direct waste from oil that might require water for handling. Petroleum coke, a refinery product often burned for heat or power, is often high in sulfur and other contaminants but low in ash. EIA Form 923 data indicate that coal-fired power plants are responsible for over 95% of ash generation at electricity producing facilities, so this analysis neglects any ash handling from petcoke. Most other oil is burned onboard transportation vehicles that do not use water.

Liquid Biofuels

The liquid biofuel fuel cycle consumes freshwater through two primary mechanisms: irrigation and biorefining. Small amounts of water are also consumed during pipeline transportation, and these carbon-based fuels produce some water upon combustion. This work estimates that freshwater consumption for US liquid biofuels is 2.9 m^3/delivered GJ for ethanol and 2.3 m^3/delivered GJ for biodiesel. Irrigation estimates are based on a 2016 analysis of the 2013 Farm and Ranch Irrigation Survey (FRIS) data, following analysis of 1998, 2003, and 2008 FRIS data by Wu et al. (2011)[58]. Water quality consumed and water quality required are both generally fresh, as the primary water demand is for irrigation. This section addresses ethanol and biodiesel in the US in 2014.

<u>Irrigation</u>

The major water use associated with biofuels is water for irrigation. Not all biofuels feedstocks require irrigation, including some feedstocks that are irrigated sometimes but not always, like corn and soy. This section adds to the biofuels water use literature by explicitly investigating feedstocks beyond corn for ethanol and soy for biodiesel and by updating prior estimates by Wu et al. (2011)[58] with 2013 Farm and Ranch Irrigation Survey (FRIS) data (USDA 2014)[62]. Much of the work on water for biomass fuels includes or emphasizes crops prospective for energy use in addition to those in use (e.g., Gerbens-Leenes et al. 2009, Harto et al. 2010, Wu et al. 2014)[63–65]. Given this analysis' focus on characterizing the 2014 US energy system, these prospective crops (e.g., switchgrass and jatropha) are not assessed.

Ethanol

Grain corn is not the only feedstock for US ethanol production, but it is dominant. DOE does not currently release feedstock data for ethanol, unlike current practice for biodiesel (USDA 2017, "Biofuels feedstocks")[66]. Starting in 2015, however, the National Agricultural Statistics Service (NASS) shows sorghum inputs "for fuel alcohol" (USDA 2017)[67]. No such category exists in NASS for sugarcane or sugar beets, so this research investigates only corn and sorghum.

Corn ethanol This work updates Wu et al.'s analysis (2009, updated in 2011 by Wu and Chiu)[58] of irrigation water intensity for corn based on the 1998, 2003, and 2008 FRIS data by replicating the analysis using the 2013 FRIS (USDA 2014)[62]. Analytical detail can be found in the original references. In brief, FRIS corn irrigation data is retrieved for each corn producing state and taken as the withdrawal volume for corn irrigation, and state-level irrigation return flow percentages reported by the USGS for 1995 (Solley et al. 1998[8], the last time consumption was estimated by USGS) are used to calculate the consumptive amount. Irrigation and production are rolled up into USDA Farm Production Regions as shown in Figure 6 of Wu et al. (2011)[58]. Groundwater and surface water proportions are calculated based on the total acreage irrigated by groundwater and surface water systems, ignoring the contribution of off-farm water sources (which supply about 7% of corn acreage as reported by FRIS), assuming that the amount of water withdrawn and consumed per acre is the same for groundwater and surface water-fed acreage. After the irrigation intensity is calculated, total volumes are adjusted to the 2014 base year used for this project. National Agricultural Statistics Service (NASS) data include the irrigated and nonirrigated acreage for corn during noncensus years only for a few states (USDA 2017)[67], so irrigated acreage for corn by state for 2014 is estimated by scaling the 2013 FRIS value for irrigated acreage by the ratio of 2014 to 2013 corn production in the state, adjusted for state-level differences in yield between 2013 and 2014. This technique implicitly assumes that the irrigated proportion of corn acreage by state is the same for 2013 and 2014. Further, this analysis assumes that corn ultimately processed into ethanol is corn grown for grain (as opposed to sweet corn or corn for silage) and is not more or less likely to be irrigated than corn in general.

Ground- and surface water irrigation consumption and withdrawal by state are calculated as

$$\frac{I_{\text{irrigated}} \times A_{\text{irrigated}} \times \%_{\text{water source}}}{P_{2014}} \times \frac{\text{bushel}}{\text{gallon}} = I_{\text{ethanol}},$$

where *I* is irrigation intensity (either consumption or withdrawal, where the ratio is determined by 1995 USGS state-specific factors as in Wu and Chiu 2011)[58], *A* is acreage, "%" is the proportion of water from surface or ground sources, based on acres irrigated with each, and *P* is total production in bushels. These state values are then rolled up to regional irrigation intensity on a corn grain production weighted average basis for 2014. For most regions, corn production and operational ethanol refining capacity proportions are similar (Table S2).

Table S2. Regional summary of corn irrigation needs for ethanol production in the US, 2014

				Irrigation Consumption		Irrigation Withdrawal	
Region	2014 share of US ethanol production capacity (%)[1]	2014 share of US corn production (%)[2]	Sufficient corn production in region to support ethanol production?	Surface water (vol/vol)	Ground water (vol/vol)	Surface water (vol/vol)	Ground water (vol/vol)
1	2%	3%	yes	2	6	2	7
2	2%	3%	yes	2	8	2	8
3	1%	2%	yes	19	58	19	60
4	2%	6%	yes	10	123	13	171
5	48%	45%	yes	0	9	0	9
6	13%	14%	yes	2	21	2	22
7	27%	23%	yes	5	237	6	262
8	2%	2%	yes	8	427	10	518
9	2%	1%	yes	45	320	113	797
10	2%	0%	no	5	87	7	107

Sources: [1]RFA 2015; [2]USDA-NASS 2016

Note: “vol/vol” denotes volume of water per volume of denatured ethanol

This work adopts the initial assumption that corn biorefined into ethanol is grown in the same region as the biorefinery. However, Region 10 (California, Oregon, and Washington) does not produce sufficient corn to supply its biorefining capacity, about 1.5% of the national total (RFA 2013, USDA 2017)[11,68]. Given the very close match between operational capacity and ethanol production in 2014 (14,300 million gallons produced using 14,575 million gallons of operating capacity, RFA 2013)[68], assuming that capacity factor is not close to 0 for the 219 million gallons of production capacity in Region 10 suggests that Region 10 imports corn for processing. The other nine regions are able to cover their feedstock requirements. In practice, many might import corn from cheaper and less water intensive growing regions, but for this analysis, corn is assumed to come from same region as the refinery except for Region 10, where corn is assumed to be imported from around the US proportional to the amount of total corn grown (the implication is that Region 10 water intensity is assumed to be the US average, including Region 10). Region 10's highly water intensive corn cultivation, particularly in California, has been noted in the literature in the past (Fingerman et al. 2010)[69], so the assumption of imported corn is relevant from a water accounting perspective. Since Region 10's corn production is highly water intensive relative to the rest of the country, this importation assumption reduces the overall estimate for irrigation water intensity for corn ethanol by about 15% (13% for consumption, 17% for withdrawal).

As shown in Table S2, the contribution made by this analysis is not only updating Wu and Chiu's analysis (2011)[58] using FRIS 2013 data but also accounting for irrigation demand in smaller corn producing regions. Though it is possible that the assumption that biorefineries privilege corn from their own regions is incorrect, accounting for irrigated corn for ethanol outside regions 5, 6, and 7 increases the estimate for overall irrigation water intensity substantially. For 2013 data, assuming Region 10 draws from a national corn mix, accounting for corn outside regions 5, 6, and 7 (18% of production) raises the consumptive irrigation intensity estimate by 14% (withdrawal by 25%), as irrigation in those regions is on average twice as consumptively intensive as in regions 5, 6, and 7 (withdrawal is three times as intensive). Performing the same analysis for 2008 data analyzed in Wu and Chiu (2011)[58] suggests that including regions 1-4 and 8-10 would increase the irrigation consumption estimate by 40%, even though those regions accounted for less than 15% of corn production. This discrepancy between 2013 and 2008 is likely due to the more widespread drought conditions in 2008, contributing to higher irrigation demand and lower yield overall (NCEI 2009, NCEI 2014)[70,71].

Several conversion factors are needed to find the irrigation intensity of ethanol rather than corn. First, this work assumes a corn bushel-to-gallon of ethanol conversion of 0.38, based on USDA figures for 2015, the first year USDA implemented the Current Agricultural Industrial Reports program tracking ethanol (USDA 2017, CAIR)[72]. This value is effectively the same as the 0.37 bushel per gallon value used by Wu et al. (2011)[58]. Second, fuel ethanol is assumed to contain 5.797 mmbtu/bbl feedstock and 3.558 mmbtu/bbl ethanol (EIA 2017, Total Energy, Table A3)[73]. The last factor applied is the most subjective. Namely, corn crops designated for ethanol produce saleable co-products, which means that some method of allocating impacts like water intensity across the products is required. Multiple allocation techniques are available, including mass-, energy-, value-, and displacement-based approaches (see e.g., Wang et al. 2011)[74]. This analysis departs from Wu and Chiu (2011)[58] and follows examples like that of Mathioudakis et al. (2017)[75] in choosing to allocate water intensity to corn ethanol co-products based on financial value, rather than e.g., carbon displacement as in Wu and Chiu (2011)[58]. Essentially, this assumption suggests that farmers are making their primary water allocation decisions based on monetary value rather than e.g., mass or displacement. As this research is a single-year snapshot, one of the major problems with economic allocation—the fact that prices vary over time—is less relevant than it might be for a longer-term investigation. Based on 2014 prices, and noting that a limitation of this method is that the value fraction as reflected in end products might not be the same as the value fraction observed by the farm, this analysis assigns about 70% of the blue water irrigation intensity to ethanol rather than to the coproducts DDGS and corn oil (Table S3).

Table S3. Corn coproduct allocation for ethanol

coproduct	mass fraction[1]	price in $/ton, 2014	value fraction
ethanol	0.538	462[4]	70.5%
DDGS	0.422[2]	172[5]	20.6%
corn oil	0.040[3]	788[6]	8.9%

Sources: [1]Lampert et al. 2016, Table S.9; [2]Value from Lampert S.9 less value of corn oil, assuming that non-ethanol component is 13.5 lb 20% protein + 2.5 lb 60% protein + 1.5 lb corn oil: https://www.e-education.psu.edu/egee439/node/672; [3]Assuming that non-ethanol component is 13.5 lb 20% protein + 2.5 lb 60% protein + 1.5 lb corn oil: https://www.e-education.psu.edu/egee439/node/672; [4]Table 14, 2014 calendar year: https://www.ers.usda.gov/data-products/us-bioenergy-statistics/us-bioenergy-statistics/#Prices. $1.52/gal, this is corn cost per gallon ethanol. Lampert et al. 2016, S.1: 2.98 kg/gal ethanol; [5]Table 9, 2014 calendar year: https://www.ers.usda.gov/data-products/us-bioenergy-statistics/us-bioenergy-statistics/#Prices; [6]Table 7, 2013/2014 marketing year: https://www.ers.usda.gov/data-products/us-bioenergy-statistics/us-bioenergy-statistics/#Prices. 39.43 cents/lb

Sorghum ethanol Data on 2014 sorghum consumption for US production of fuel ethanol are not centrally available, but trends show increasing use of the sorghum crop for fuel ethanol, with about 2% of the crop used for fuel alcohol in 2015 and about 9% in 2016 (USDA 2017, NASS QuickStats, assuming 0.56 bushels/cwt for grain sorghum)[67]. Sorghum ethanol yield per bushel is similar to corn ethanol yield per bushel, at about 2.4 gal/bu (4.3 gal/cwt) (USDA 2002)[76]. In 2015, sorghum for fuel ethanol accounted for less than 1% of total US ethanol production (USDA 2016, Grain Crushings and Co-Products Production)[77], with the remainder of USDA-reportable feedstock being corn. Thus, this work assumes that irrigation of non-corn crops for ethanol produced in 2014 is negligible for this water analysis. Note, however, that sorghum and other substitute ethanol crops (including sugar beets) often have lower irrigation water intensity than corn per unit of ethanol (Montross et al. 2009, Saballos 2008, Zegada-Lizarazu and Monti 2012, though see Gerbens-Leenes et al. 2009 for a less favorable global view of sorghum)[63,78–80].

Biodiesel

Irrigation water associated with three main inputs to biodiesel production in 2014 are analyzed here: soybean oil (4,869 million pounds), canola oil (1,046 million pounds), and corn oil (977 million pounds) (EIA 2016, Monthly Biodiesel Production Report Table 3)[81]. An additional 1,057 million pounds of animal fats, 1,289 million pounds of recycled feeds, and 150 million pounds of "other" feedstock inputs (EIA 2016, Monthly Biodiesel Production Report Table 3)[81] are assumed not to require additional water input for production.

Soy biodiesel The major crop used for US biodiesel is soy, with an estimated 11% of production grown on irrigated acreage. As for corn, this work uses state-level 2013 and 2014 data (USDA 2017)[67] to update estimates for the water intensity of soy from GREET's 2007 and 2008 data (Lampert et al. 2015)[82]. Using a similar approach as that described above for corn, the irrigation intensity for the entire US soy crop is estimated at 572 gal/bushel withdrawals and 453 gal/bushel consumption. In 2014, about 4,869 million pounds of US soybean oil (EIA 2016, Monthly Biodiesel Production Report Table 3)[81] were used for biodiesel production. As with corn, the soybean crop produces multiple valuable products, not all of which are used for energy. Again, this analysis uses financial allocation (Table S4). Here, this choice follows the hypothesis that farmers are growing soy (and allocating water) because of the high-value biodiesel product, with some additional benefit from the higher mass but lower value soy meal animal feed coproduct, so more of the water burden should be assigned to the biodiesel. The choice of allocation technique is more relevant for soy than for corn because of the greater discrepancy between allocation fractions for soy (Lampert et al. 2016, Tables S.9 and S.12)[83]. This work updates Wang et al. (2011)[74] with 2014 market data, noting that it is not clear that the value fraction of the end products is the same as the value fraction observed by the farm.

Table S4. Soy coproduct allocation for biodiesel

coproduct	mass fraction[1]	price, 2014 ($/ton)	value fraction
biodiesel	20.2%	1127[2]	42.4%
soy meal	77.4%	368[3]	53.1%
glycerin	2.4%	990[4]	4.4%

Sources: [1]Lampert et al. 2016, Table S.12; [2]Average of quarterly national averages, B99/B100 (Table 11), http://www.afdc.energy.gov/publications/search/keyword/?q=alternative%20fuel%20price%20report and per Lampert et al. 2016, Table S.1, biodiesel density of 3.361 kg/gal to convert $4.175/gal to $/ton; [3]2014, table 4, https://www.ers.usda.gov/data-products/oil-crops-yearbook/oil-crops-yearbook/#Soy and Soybean Products; [4]January 2014, https://www.icis.com/globalassets/global/icis/pdfs/sample-reports/chemicals-glycerine.pdf, though note extreme price volatility in part due to biodiesel production (Ciriminna et al. 2014).

Assuming 10.7 pounds of crude soybean oil per bushel in addition to meal byproducts (USSEC 2015)[84] and 4,869 million pounds of soybean oil used for biodiesel in 2014 (EIA 2016, Monthly Biodiesel Production Report Table 3)[81], an estimated 455 million bushels of US soybeans were used to produce biodiesel in 2014. Using Table S4 and estimated withdrawal and consumptive water intensity of 572 and 453 gal/bushel of US soybeans, respectively, and assuming 96% mass yield of biodiesel from soy oil (Lampert et al. 2016, Table S.11)[83], irrigation water intensity is estimated at 1.6 m^3/ delivered GJ of consumption and 2.0 m^3/delivered GJ of withdrawals, all freshwater. Note this analysis assumes that soybeans devoted to biodiesel have the same irrigation profile as US soybean production as a whole, which might not be accurate.

Canola biodiesel As of the 2012 USDA Census of Agriculture (USDA 2014, accessed through Quick Stats 2.0)[85], about 1.5% of US-grown harvested canola acreage was irrigated.

(Rapeseed, a very similar crop, was harvested from about 3,000 acres in 2012, in contrast to nearly 2 million acres for canola, and is thus ignored.) Given the low proportion of irrigated canola, this work assumes no blue water irrigation footprint for canola-derived biodiesel.

Corn biodiesel In addition to starch-based ethanol, the US corn crop contributes to biodiesel production through corn oil. As of 2014, corn oil accounts for about 9% of the value of a given energy-allocated unit of corn (Table S3). Using the same logic as above, corn irrigation water is allocated to biodiesel based on the value fraction of corn oil, noting that the value fraction as reflected in end products might not be the same as the value fraction observed by the farm. The volume of corn oil converted to biodiesel is about 15% of the corn oil produced from the corn ethanol crop; the remainder enters other product streams. Irrigation water intensity for corn biodiesel is estimated at 0.75 m^3/ delivered GJ of consumption and 0.93 m^3/delivered GJ of withdrawals, all freshwater.

Transportation

Liquid biofuels are most commonly transported in tanks on trucks, trains, and barges. Dedicated pipelines for liquid biofuels are rare, with about 16 miles of pipelines dedicated to liquid biofuels in the US as of 2014, compared to over 125 thousand miles of pipelines dedicated to petroleum products and about 2.5 million miles of pipelines for natural gas (PHMSA 2017)[35]. Concerns about contamination mean that blended ethanol and biodiesel are not typically transported in petroleum pipelines (Galbraith 2009, US DOT 2017)[86,87]. While transportation containers and the limited biofuel pipelines use water for hydrostatic testing and cleaning, water use associated with biofuel transportation is considered negligible. Note that as with other fuels, water used for cleaning transportation vessels is subject to contamination concerns.

Biorefining

Corn ethanol

As summarized in Lampert et al. (2015)[82], based on Mueller and Kwik (2013)[88], we assume 2.7 gallons of freshwater per gallon of dry milled ethanol fermentation is consumed, accounting for about 90% of ethanol production (USDA 2016, Grain Crushings and Co-products Production)[77]. Lampert et al. (2015)[82] also report that wet milling ethanol consumes 3.92 gallons of water per gallon of ethanol, accounting for the remaining 10% (USDA 2016, Grain Crushings and Co-products Production)[77]. A total of 14,300 million gallons of ethanol were produced in 2014 (EIA 2017, "Fuel Ethanol")[89]. Water is assumed to be 90% consumed, based on an assumption that these typically groundwater-based systems with heavy process water recycling consume most of their water. Note also that as the industry matures, these data will likely change to reflect learning, economies of scale, etc., so data vintage is relatively important.

Water sourcing is assumed to be 5% surface water and 95% groundwater, in line with irrigation needs estimated from FRIS, given that plants are likely to be close to growing areas. This is corroborated by e.g., practice in Minnesota, where groundwater dominates supply for ethanol biorefineries (Minnesota Technical Assistance Program 2011)[90]. Like irrigation water, all biorefining water is assumed to be fresh.

Biodiesel

The approach to refining feedstocks into biodiesel varies based on feedstock. Crops are first converted to oil, then the oil is converted to biodiesel. Inputs like waste oil already exist in oil form and are therefore converted directly to biodiesel, potentially after some purification. This analysis uses data from Tu et al. (2016)[91] to estimate these processing needs at 0.17 vol water/vol biodiesel consumed for crop-to-oil processing and 0.31 vol water/vol biodiesel consumed for biodiesel production. For soy biodiesel, the estimate of about 0.5 vol water/vol biodiesel is lower than the estimate of 0.66 gallons in Lampert et al. (2015)[82], likely because the data in Tu et al. (2016)[91] are somewhat newer. Oil processing values are based on 2008 data reported in a survey to an industry group (Omni Tech International 2010)[92], and biodiesel production water intensity is based on responses to a survey conducted for Tu et al. (2016)[91]. Contributors to water use include purification steps, washing (for those manufacturers employing a water wash), cooling tower use, and boiler use. Note that while the data gathered by Tu et al. (2016)[91] are recent and reflect more than a single case, they are not necessarily industry-representative due to a low survey response rate. Also note that oil processing values are based on soybean processing but for this work are also applied to other oil crops. As biodiesel production is a relatively new industry, data vintage matters, and water intensity will likely fluctuate as the landscape changes. Typically for industrial processes, intensities decline over time as larger plants built based on more experience come online. Withdrawals are calculated assuming that consumption is 90% of withdrawals.

A total of 1,280 million gallons of biodiesel were produced in 2014 (EIA 2017, "Renewable Fuels Except Fuel Ethanol")[93]. Water sourcing is assumed to be 8% surface water and 92%

groundwater, in line with soy irrigation needs as estimated from FRIS. All of this is assumed to be freshwater.

Combustion

Biofuel releases water alongside CO_2 when it is combusted. This water is an addition to the active hydrologic cycle, as combustion occurs within the boundaries of the active hydrologic cycle. Combusting bioethanol produces about 0.04 m^3 of fresh water vapor/GJ delivered, assuming an average H/C ratio of three and an energy density of 29.3 GJ/tonne. Combusting biodiesel produces about 0.03 m^3 of fresh water vapor/GJ delivered, assuming an average H/C ratio of two and energy density of 44.9 GJ/tonne, as for petroleum. This can be considered production of surface water, which may fall as rain and either remain fresh or become part of the ocean.

Coal

The coal fuel cycle consumes freshwater through mining, preparation, power generation, sulfur scrubbing, and ash handling. This work estimates that, on average, US coal consumes 0.3 m^3/delivered GJ of freshwater through these mechanisms based on a 2017 analysis, noting that water use is highly site specific and nonlinearly related to production volumes. In particular, estimated dewatering volumes per unit energy extracted vary by a factor of 1,000 across the US' major coal provinces. US coal consumes an estimated 0.3 m^3/delivered GJ and withdraws an estimated 16 m^3/delivered GJ, over 95% of which is freshwater.

This analysis finds that non-power plant coal-related freshwater consumption is about 10 times prior literature estimates based on older and less detailed information. Despite this higher estimate, this work also updates the literature by noting that two frequently cited coal-related uses of water, both relatively large, are not currently applicable. Specifically, modern US coal mine reclamation does not appear to require large volumes of water, and the last coal slurry pipeline in the US ceased operations in 2005, despite persistent citations in the literature referencing their use.

Overall, water withdrawal and consumption are reported for the three major coal ranks used in the United States: subbituminous coal, bituminous coal, and lignite. Given large variations in mining practices, mining water is described for each of five coal regions, which are then distributed across the coal ranks according to typical coal qualities in each region.

<u>Mining</u>

Coal mining takes two primary forms: surface mining and underground mining. In each case, water is used for both industrial uses (like dust control and equipment washing) and human uses (like drinking and sanitary water for mine workers). This water is typically supplied either from water that enters the mine or from additional groundwater wells. Total volumes in addition to those accounted as water entering the mine are assumed to be relatively small. Coal mines withdraw and consume substantially more water than they actively seek because of mechanisms related to the geology of the mines, primarily dewatering and depressurization. Dewatering and depressurization are processes by which mine operators remove water that has accumulated in and around a coal seam both before and during mining, with the goals of ensuring access to the coal and ensuring that the work area is dry. A second mechanism that is well known but extremely difficult to quantify is subsidence-related drainage, a process by which water from overlying strata is drained from surface sources or aquifers into mines or collapsed areas below the aquifers (see e.g., Booth 2002)[94]. In both cases, the water removal is nondiscretionary, and the volumes themselves are incidental to geology: if a given mine did not have water intersecting the mined area, it would not be necessary to obtain water for dewatering in the way that it would be necessary to obtain water for dust control. The result is that water intensity of coal mining is highly region-specific and is nonlinearly related to production volumes.

This work adopts the convention that dewatering is a consumptive withdrawal, as water is removed from its source and not returned. While this definition is consistent with definitions included in documents like ISO 14046 (2014)[95] and legal definitions in jurisdictions like Texas, where dewatering water is considered a consumptive withdrawal unless the water is specifically earmarked for another user (Grubert et al. 2012)[31], dewatering is often excluded from consideration as consumption (and sometimes even as withdrawal, e.g., Maupin et al. 2014)[9] because the water is a nuisance that operators need to remove but do not need to secure. At least one major coal mining state (West Virginia) exempts water encountered by coal mining from definitions of withdrawal, and the water might even be considered a beneficial production of water that contributes to downstream river flows for other users (Smith 2016)[32]. Despite the possibility of later beneficial use (which also applies to any other discharge), dewatering occurs because of mining rather than because of an identified need for the water by a direct user and is thus considered a mining-related consumption of groundwater in this work.

Other geology-related drivers of water removal from its original source are more difficult to quantify meaningfully, so they are summarized here but not included in the overall analysis. Such drivers are likely more important in eastern and interior coal basins where underground mining and mountaintop removal mining occur, as the primary non-dewatering mechanisms for water loss are subsidence-related water drainage (more common for longwall mines) and mountaintop removal-related losses of streams and aquifers due to burial or removal. During subsidence, fractures and increased porosity can lead to rapid drainage of overlying aquifers or loss of surface water temporarily or permanently into the subsurface (see e.g., Booth et al. 2002)[94]. However, this effect is difficult to quantify. While longwall mining is more likely to be associated with aquifer drainage than mines that are designed to prevent subsidence, since longwall mines allow mine roofs to collapse behind machinery as it advances, some longwall mines have successfully operated under large bodies of water without drainage (Booth et al. 2002)[94]. When drainage does occur, waters might be transferred from one aquifer to another, or they might be drained from surface water into groundwater storage or possibly out to other surface waters, and not all underground mining results in water losses (Booth et al. 2002)[94]. Further, in some cases, the drainage manifests as water that must be removed from the mines as dewatering water. Mountaintop removal mining can also lead to losses of water resources when thick sections of the surface are removed and emplaced nearby, usually in valleys. This removal can mean entire aquifers are removed, headwater streams are removed, and streams are buried (Palmer et al. 2010)[96]. This type of mining is different from other surface mines because the shape of the removal is inverted relative to conventional surface mines (an inverted “V” rather than a “V” shape, meaning that streams and aquifers might be entirely removed rather than merely disrupted), which means that water that would otherwise likely have been removed during a dewatering process instead drains to valleys or is no longer orographically captured.

Province-specific estimates

The US produces coal from multiple basins with different characteristics, including water saturation, sulfur content, and ash content, all of which affect life cycle water use (due to dewatering; wet flue gas desulfurization, or scrubbing; and ash handling uses, respectively). Notably, given impacts of characteristics like mine layout, production methods, geology, and others, water use for mining is not generally well correlated with production, so to the extent possible, measured water use is used rather than inferred from intensity estimates. Dewatering in particular is related to geology, hydrology, and other local water use, which makes intensities difficult to generalize across mines and even across years. For example, eastern mines with significant rainfall have continual dewatering needs that fluctuate heavily with weather, while the mines of the arid Powder River Basin (PRB) in Wyoming and Montana exist in a coal seam aquifer. As a further complication, PRB mines currently have almost no dewatering needs due to the rise of coalbed methane (CBM) production in the area that has almost entirely dewatered the mining region (see e.g., Myers 2009[97]; also, dust control water is often self-supplied from groundwater wells rather than mine inflow due to the extent of dewatering, pers. comm with operators, 2015). Thus, the context of a mine and particularities of its development drive water withdrawals. Given the nature of water disposition from dewatering (i.e., not returned to the original aquifer), water consumption and withdrawals are assumed to be equivalent for coal mining.

Given these highly specific conditions and this work's interest in characterizing a snapshot of US water use for energy, five major coal provinces accounting for the majority of US coal mining are characterized and then compared and aggregated to form a picture of US water use for coal mining. These regions are the Northern Great Plains (including the Powder River Basin), Appalachia (also called the Eastern Region), the Interior, the Gulf Coast, and the Rocky Mountain Region (including the Uinta Basin) (Table S5). The grouping used here does not perfectly correspond to geology, precipitation regimes, mining techniques, etc., but the simplification is made to enable relatively direct use of state- rather than basin-based data for calculation to facilitate easier updating as conditions change.

Table S5. States assigned to each coal province

Province	States
Northern Great Plains	MT, ND, WY
Appalachia/Eastern	AL, eastern KY, MD, OH, PA, TN, VA, WV
Interior	AR, IL, IN, KS, western KY, MO, OK
Gulf Coast	LA, MS, TX
Rocky Mountain Region	AZ, CO, NM, UT

No distinction is made between thermal coal for power generation and coking coal for steel manufacturing, given that both forms of coal are ultimately used as fuels. The choice to use region-level resolution in this work, particularly as opposed to differentiating between surface and underground mining, is intended to mitigate the concern that mine water use is heavily site-specific. In general, caution is advised in using intensity factors for mining. The implied water intensities for our 2014 snapshot are published in Table S6 in recognition of the fact that many analysts require a quick estimation method and to show the large differences among coal provinces.

Table S6. Coal province-specific freshwater consumption estimates

Coal Province	Percent of 2014 US coal production (%, energy basis)	Total estimated 2014 water consumption (m^3)	Estimated freshwater consumption (m^3/process GJ)
Northern Great Plains	39%	9.4×10^{6}	1.1×10^{-3}
Appalachia/Eastern	33%	1.3×10^{8}	1.8×10^{-2}
Interior	16%	4.2×10^{8}	1.2×10^{-1}
Gulf Coast	3%	4.3×10^{7}	5.8×10^{-2}
Rocky Mountain Region	8%	3.6×10^{7}	2.1×10^{-2}
US Total or Average		9.4×10^{6}	3.0×10^{-2}

Water consumption and withdrawals are estimated based on USGS estimates of water withdrawals for mining in counties with 2010 coal production, scaled to 2014 coal production (Maupin et al. 2014, EIA 2017)[9,98]; NPDES data for water discharges from SIC code 12 (coal mining, including processing) (EPA 2015)[99]; and EIA data on average heat content and production by region (EIA 2017)[98]. While USGS water withdrawals for mining include all mining—including oil and natural gas extraction—cross referencing USGS mining withdrawal data with EIA data on which US counties produce coal enables a higher resolution look at coal water intensity. In many cases, coal dominates mining at the county level. A major and important exception is the Powder River Basin, the largest producing region in the US (and the majority of Northern Great Plains production), as the USGS withdrawal estimate from coal-producing counties also captures the large amounts of water associated with oil and natural gas in many of the same counties that produce coal in the region. The Northern Great Plains estimate is thus based on a thorough review of EIS and other documentation for the Powder River Basin (e.g., HKM Engineering 2002)[100] in addition to personal communication with mine personnel in Wyoming and North Dakota. A smaller exception is the Gulf Coast production region, dominated by Texas lignite, which was characterized in detail by Nicot et al. (2011)[101] and summarized in Grubert et al. (2012)[31]. Given the 100% participation by Texas mines (accounting for 87% of Gulf Coast production by tonnage) in a water use survey described in Nicot et al. (2011)[101], and given extremely high NPDES discharge values for the Gulf region in 2014 associated with the flooding in the region that year, that estimate is used here in place of the coarser USGS and NPDES-based estimate.

For the remaining three coal producing provinces considered here, Appalachia, the Interior, and the Rocky Mountain Region, best-estimate water consumption and withdrawal intensity per unit of energy is taken as USGS-reported withdrawal (which does not include dewatering volumes) plus NPDES discharges (which do include dewatering volumes). This estimate is cross-referenced with company reports and exemplar data for each region based on e.g., state water plans, EIS for particular mines or mining complexes, and other mine-specific information for validation. The slightly counterintuitive addition of NPDES discharges to USGS withdrawals rather than subtraction of NPDES discharge from USGS withdrawal to estimate consumption is explained by recognizing NPDES discharges are primarily dewatering volumes while USGS withdrawals are abstractions used for consumptive mine water uses like dust control and equipment washing (Maupin et al. 2014)[9]. This estimate does not capture water reuse. Due to the inclusion of storm water runoff in the NPDES volumes, estimates made here are likely somewhat high for mines in wet regions. However, water consumption due to e.g., groundwater loss to underground mine workings or through channels caused by subsidence is not captured.

Overall, estimates for freshwater consumption for coal mining are about ten times the estimate in Gleick (1993)[2], which is one of two major sources frequently re-cited in the literature. The original data used to produce Gleick's (1993)[2] estimate of 2.0×10^{-3} m^3/GJ extracted for surface coal mining and 3.0 to 20×10^{-3} m^3/GJ extracted for underground coal mining are several decades old and not American, which could explain the difference. The other commonly used estimate comes as United States Geological Survey (USGS) guidance, which suggests withdrawals of 50 – 59 gal/short ton (Lovelace 2009)[102] (linear average of 9.7×10^{-3} m^3/GJ extracted based on 2014 average energy density of coal production of 20.146 mmbtu/short ton, EIA 2017 Table A5)[98]. This USGS estimate does not include dewatering and is not region-specific.

Regional estimates reported in Table S6 can be validated against corporate reports of water use by coal mining companies, specifically via the standardized index used by the Global Reporting Initiative (GRI) (2017)[103], using information about coal production, coal heat content, and mine locations by company to produce an estimate of water use that can then be compared to the reported figures. Of the top 10 US coal producers as of 2014 (EIA 2016, 2014 Annual Coal Report Table 10)[104], Peabody Energy (19% of 2014 US production by tonnage), Arch Coal (13.2%), and CONSOL Energy (3.2%) report GRI water metrics for at least one recent year. Alpha Natural Resources, at 8.0% of 2014 US production by tonnage, is listed in the GRI database, but the GRI table links are dead and not available using digital archives as of September 2016. Using reported production volumes, coal heat content, and the water consumption estimates in Table S6 to estimate consumptive water intensity per unit energy, estimates match relatively closely. Comparisons of reported values and estimated values based on Table S6 are summarized in Table S7. Upheaval in the coal industry leading to non-steady state extraction strategies and unclear accounting of water that never leaves corporate boundaries (like dewatering water used for dust control) contribute to uncertainty. While these estimates thus provide some indication that the regional intensities in Table S6 are accurate, they should not necessarily be interpreted as stable, high resolution data.

Table S7. Comparison of coal mining water intensities estimated in this work with reported company-specific data

Company	Reported intensity based on GRI (m^3 water / GJ coal)	Estimated intensity based on Table S6 (m^3 water / GJ coal)	Difference (% of reported intensity)
Peabody Energy (2014 GRI)	2.1×10^{-2}	2.3×10^{-2}	3% with dewatering -39% without
CONSOL (2014 GRI)	1.5×10^{-2}	1.6×10^{-2}	-2% with dewatering -39% without
Arch Coal (2012 GRI)	6.5×10^{-3}	8.6×10^{-3}	-40% (excludes dewatering)

The largest difference between reported and estimated water intensity is for Arch Coal, with Table S6 values overestimating the reported value by 40%. This larger value is almost certainly due to the fact that Arch does not report water associated with mine dewatering: when such waters are excluded from the estimates for Peabody and CONSOL, intensity estimates decline by 42% and 37% of the reported intensity, respectively, indicating that dewatering likely accounts for the gap for Arch. The similarity between estimates and reported values across these three companies, with production in multiple regions, increases confidence in the water intensity estimates presented in Table S6. Note that the water intensity of Peabody's Australian assets, about 20% of the company's production on an energy basis, is estimated based on GRI reported water use by Centennial Coal, an Australian producer.

Reclamation

Current estimates of water consumption related to coal mining suggests that reclaiming mined lands via revegetation consumes large amounts of water (Gleick 1993)[2]. This estimate of revegetation-related water consumption is derived from a 1977 National Academies publication estimating potential water needs for coal mining in the semi-arid regions (NAS 1977)[105], not empirical data. Discussions with six professionals working in three major coal provinces, including the semi-arid regions, and who have direct experience with all five major coal provinces, indicate that in practice, irrigation is not used for revegetation during mine rehabilitation. A strong emphasis on re-seeding with native plants, sometimes via hand collection of seeds from the immediately local area (e.g., Schuman et al. 2000)[106], supports this assertion that water is not routinely used for revegetation. Similarly, the date of the estimate for revegetation requirements in the semi-arid regions (well before large-scale rehabilitation had been attempted, as the publication came out at the beginning of the development of the Powder River Basin) and its emphasis on risk assessment for the region that likely lead to an interest in potential overestimates for the sake of comprehensiveness indicate that its conclusions can be superceded by the direct experience of modern practitioners.

Thus, this work updates the literature by noting effectively no water use for revegetation over rehabilitated coal mines. This finding is significant, as prior published estimates assumed revegetation consumed 1.5 times as much water as surface coal mining itself, irrespective of the location (e.g., in the semi-arid versus humid regions) of the mining (Gleick 1993)[2]. We do not consider mining-related changes to infiltration patterns due to effects like compaction (which can reduce infiltration) and deforestation (which tends to increase infiltration) (Hawkins and Smoyer 2011)[107].

Preparation

Coal preparation (also called washing or cleaning) is a term for intermediate non-transportation steps between the mine and the power plant to improve coal quality, often by reducing ash or sulfur content. Not all US coal is washed: lower value coals are less likely to be washed due to the relatively high cost of washing, which is difficult to offset for low-value coal. Coal preparation often proceeds by crushing the coal to an intermediate size (between highly variable run-of-mine (ROM) size and the pulverized powder used in pulverized coal (PC) power plants that exist in the US), then using large volumes of water to perform a physical separation between the combustible organic material (coal) and waste like the noncombustible mineral material (ash). At the end, the fines-filled water that is not recycled is frequently impounded in slurry dams. Not all coal preparation processes involve water, but because this solid-liquid separation technique is so common (Luttrell 2008)[108] coal preparation is also often called "washing." Wet coal cleaning techniques are typically more efficient than dry techniques, though not all coals respond well to water-based washing (NETL 2012, p. 20)[109]. Other methods of coal preparation do not involve large amounts of water, including gravity separation and other techniques. The extent to which such preparation methods are deployed in the US will not be carefully examined in this work due to the focus on water use.

Coal washing operations require large volumes of water, but this water is often recycled, making exact characterization of water consumption challenging. Estimating the amount of water used for coal washing proceeds by first deriving an estimate of the consumptive and withdrawal intensities associated with coal washing, then determining the total amount of coal that is washed in the United States. Data on coal prep plant water use are not widely available, but this work identifies four independent estimates that are in relatively close agreement. The first is the widely-cited estimate from Gleick (1993)[2], which implies a consumptive water intensity of 0.11 m^3 freshwater/tonne of prepared coal (converted from 0.004 m^3/GJ: given the nature of coal washing, tonnage is likely a better metric than energy for estimating total water use). A second estimate is from a pre-operational assessment of a coal prep plant in the environmental impact statement for the Allen-Warner Valley project (BLM 1980)[110], which implies a consumptive water intensity of 0.19 m^3 and withdrawal intensity of 0.99 m^3 freshwater/tonne of prepared coal. A third estimate from a 1991 reference handbook suggests that "new" plants consume about 0.2-0.25 m^3 water per tonne of coal, which is in line with a much more recent estimate from a Chinese source (Li et al. 2014)[111] indicating a consumptive water intensity of 0.20 m^3 freshwater/tonne of prepared coal, including 0.15 m^3/tonne incorporated into wastes and byproducts (like slurries) and 0.05 m^3/tonne consumed and not incorporated into wastes and byproducts. The same source indicates withdrawals of 2.5 m^3 freshwater/tonne of prepared coal. While up-to-date, nationwide estimates for water usage by coal preparation plants in the United States would be preferred, this work prioritizes the recent and higher-coverage Chinese estimate (Li et al. 2014)[111].

Given an estimate of consumptive and withdrawal water intensity for coal preparation, the total volume of water used for coal washing in the US in 2014 can be estimated using information about the total amount of washed coal. Determining the amount of coal that is washed in the United States requires several assumptions, as the data from EIA Form 7A are not publicly reported. The trade publication *Coal Age* publishes an inventory of coal preparation plant capacity annually (Fiscor 2014)[112], but actual throughput is not available. This research estimates that about 35% of US coal is washed, by tonnage, an estimate derived by comparison of coal preparation plant inventories with data on coal production by location and quality. Specifically, this work crossreferences by-state coal preparation plant capacities from the 2014 Coal Age Prep Plant Census (Fiscor 2014)[112] with EIA data on coal production volumes, heat content, sulfur content, and ash content (EIA 2017)[98]. Key assumptions include the idea that all metallurgical coal is washed (see e.g., Alvarez 2014)[113] and that high energy density, high sulfur coals are washed. Some more specific situations are also included, such as the existence of a single prep plant at an underground mine in Montana that suggests low sulfur bituminous coal in Montana is washed (Fiscor 2014)[112]. Similarly, the knowledge that there are no prep plants in Arizona or New Mexico suggest that Southwestern mid-sulfur bituminous coals are not washed (Fiscor 2014)[112]. Where coal is assumed to be washed, implied wash volumes are compared to regional washing capacity to confirm sufficient infrastructure is available. Using these assumptions, this work estimates that all metallurgical coal and about 29% of thermal coal tonnage (34% of thermal coal energy) in the United States is washed, for about 35% of total tonnage (42% of total energy). This estimate is consistent with prior estimates. A 1982 estimate indicates that 100% of met coal and less than 25% thermal coal was washed (Wolfe and Walia 1982)[114] while a 1994 estimate suggests that 45-50% of US coal was washed at the time (Fonseca 1994)[115]. A 15-20% rise in unwashed PRB coal's market share of the roughly consistent total produced tonnage in the intervening two decades (EIA 2017, Form 7-A)[98] suggests that the estimate made here of 35% washed total tonnage is accurate. We note that while this work takes a snapshot of 2014 conditions, US coal volumes have declined dramatically in the last two years (EIA 2016, Annual Coal Report, Table 1)[104] and are expected to continue to decline (EIA 2017, Annual Energy Outlook)[116].

Based on the assumptions described in the preceding paragraphs, this work estimates total freshwater withdrawals and consumption for coal washing in the United States in 2014 at 7.5×10^8 m^3 and 6.0×10^7 m^3, respectively. All water is assumed to be fresh, and sources are assumed to be 65% surface and 35% groundwater based on assumptions in Leonard (1991)[117] and supported by the similar ratios of both domestic and agricultural water withdrawals (Maupin et al. 2014)[9]. Average regional water intensities (accounting for the proportion of coal washed in each region) are summarized in Table S8.

Table S8. Water consumption and withdrawal for coal preparation in the US by producing province

		Consumption		Withdrawal	
Province	**Percent of 2014 US coal production, energy basis**	**Total (m^3)**	**Intensity (m^3/GJ produced)**	**Total (m^3)**	**Intensity (m^3/GJ produced)**
Northern Great Plains	39%	1.6×10^{6}	1.9×10^{-4}	2.0×10^{7}	2.4×10^{-3}
Appalachia/Eastern	33%	3.0×10^{7}	4.0×10^{-3}	3.8×10^{8}	5.0×10^{-2}
Interior	16%	2.5×10^{7}	7.6×10^{-3}	3.1×10^{8}	9.5×10^{-2}
Gulf Coast	3%	0	0	0	0
Rocky Mountain Region	8%	6.5×10^{6}	4.1×10^{-3}	8.1×10^{7}	5.1×10^{-2}
US Total or Average		$\mathbf{6.3\times10^{7}}$	$\mathbf{2.9\times10^{-3}}$	$\mathbf{7.9\times10^{8}}$	$\mathbf{3.7\times10^{-2}}$

As the total amount of water involved in coal preparation is relatively small, this work notes but does not investigate two additional details. First, high moisture coals like lignite can be subjected to drying or dewatering procedures (Rao et al. 2015)[118] that technically reintroduce water previously bound in coal to the active hydrologic cycle. Second, coal washing can improve power plant efficiency (typically by 1-2%), reducing cooling water needs, and can reduce water needs for ash handling later, as ash is often handled via water-based slurry. One Indian example suggests that a 10% reduction in ash means a 30% reduction in water consumption at the power plant (RAP 2013)[119]: results from this work indicate that coal washing consumes about 10% as much water as power conversion per unit energy of washed coals, which would suggest that the water investment in washing is offset by savings at the power plant if the relationship holds (note that the amount of ash removal from US coal washing is not well characterized in this work, however).

Power generation

Power plant operations and cooling

Please see the section on Thermoelectric Power Generation for details on the calculation of water use for cooling at coal-fired power plants.

Sulfur management

Coal-fired power plants, like refineries, often have active sulfur management requirements because the combustion of sulfur-bearing fuels like coal produces sulfur oxide (SO_x) compounds that are regulated air pollutants. There are two major approaches that coal-fired power plants take to managing sulfur: active SO_x removal with equipment called scrubbers or use of low-sulfur coals. Sulfur management is a major driver of the growth of mining in the Powder River Basin, which contains abundant low sulfur coal with a tradeoff of low energy density (EIA 2017)[98]. (Note that recent trends have shifted away from preference for low sulfur PRB coal in favor of high energy density coals in the Non-Gulf Interior region that were previously not used due to their high sulfur content: widespread required installation of sulfur scrubbers for control of mercury and air toxics (EIA 2014)[120] has effectively removed the advantage of not having to install sulfur scrubbers that burning low sulfur coal could provide.) Both techniques have water use implications: plants burning lower-heat coals like PRB coal are less efficient (see e.g., Nowling 2015 for relevant anecdotes about heat rate at coal plants)[121], which increases their water needs relative to an equivalent plant burning higher-heat coals, and sulfur scrubbers often require large volumes of water both because of efficiency hits and because of the prevalence of wet scrubbers that combine lime or limestone with a water spray for sulfur removal.

Results of this work differentiate among lignite, subbituminous coal, and bituminous coal. Even though some power plants that would likely otherwise have burned bituminous coal burn subbituminous coal as a sulfur control mechanism, we do not attempt to attribute additional water consumption associated with subbituminous coal use to sulfur control. While initial shifts to subbituminous coal were strongly associated with sulfur compliance because the major subbituminous US resource is low sulfur, it is harder to state that plants burn this coal primarily because of sulfur concerns under present conditions (now, scrubbers are frequently required even for coal-fired power plants burning compliance coal, and the infrastructure of the Powder River Basin already exists). However, our data suggest that the 2014 US coal-fired power plant fleet burning subbituminous coal (primarily from the Powder River Basin) consumes and withdraws about 20% more water per unit of energy than the 2014 US coal-fired power plant fleet burning bituminous coal (see Data File S1).

Though we ignore these structural approaches to sulfur control, we do characterize the difference in water consumption and withdrawals attributable to active sulfur removal strategies like scrubbing. Average sulfur content in US coal was 1.16% in 2014 (EIA 2017)[98], up from less than 1% in 2008 (the rise in sulfur content is likely partly attributable to a resurgence in production of high sulfur Illinois coal able to meet compliance targets due to a MATS-related scrubber buildout; a slight decline from 2014 to 2015 likely reflects the timing of slowdowns and bankruptcies in different geographies of the US coal sector). Accordingly, we expect that water use for sulfur removal has also risen, as a lower average sulfur content likely implies a higher proportion of compliance coal that does not need scrubbing. While some estimates of scrubber water intensity exist (e.g., Grubert and Kitasei 2010, Zhai et al. 2011)[122,123], scrubber type, coal quality, and many other factors make an accurate bottom-up estimate for sulfur scrubbing water use challenging to construct. Instead, we disaggregate data published in EIA 923[1] to compare water consumption and withdrawals at scrubbed and unscrubbed plants across the three major coal fuel categories of bituminous, subbituminous, and lignite coal and two major cooling system categories of once through and recirculating.

Analysis proceeds as follows. First, EIA 923 data are used to associate individual US power plants with the number of megawatt hours produced by each fuel an individual power plant uses. Then, plants are characterized by fuel type and scrubber status, with filters applied to prioritize clear boundaries between wet scrubbed and not wet scrubbed coal-fired power plants in each category. That is, plants that use multiple fuels, use multiple scrubbing systems, or otherwise represent unusual cases are not used to characterize fuel-specific water use associated with wet scrubbing. Plants that use coal for at least 95% of their total output in 2014 are classified as coal plants, and plants are assigned to a particular coal type if at least 90% of their total output is associated with that coal type. Data for these plants are crossreferenced with waste byproduct data from EIA 923 to determine whether wet or dry scrubbing was in place in 2014 (in cases where multiple scrubber types are in use, a manual check was performed based on hours-in-service data for each scrubber to attempt to assign the plant appropriately; unclear cases were excluded). Total scrubbed megawatt hours are estimated based on hours-in-service data for the plant and scrubbers, and water withdrawals and consumption as reported for each plant are allocated proportionately to wet, dry, and unscrubbed megawatt hours (in the vast majority of cases, 100% of water is allocated to a single category). Finally, plants that consume less than 30% of their reported withdrawals are classified as once through systems (results are stable when this assumption is between about 20 and 50%). Results are presented in Data File S1.

The overall estimate that using sulfur scrubbers at US coal-fired power plants consumes about 0.2 m^3 of water/MWh produced (62 gallons per MWh produced) is very similar to results in Klett et al. (2007)[124] indicating about 63 gal/MWh for scrubbing. One noteworthy observation is that scrubbers seem to reduce total withdrawals per unit of plant output for plants using once-through cooling, though consumption generally grows, as expected. This observation is likely because scrubbers effectively act as plant exhaust pre-coolers that use a recirculating system. Since flue gases are cycled through scrubber units before going through the main cooling loop, they are cooler than they otherwise would be and thus require less cooling water withdrawal. The effect is not present for recirculating plants.

Two additional observations are likely data artifacts associated with the particularities of the small number of plants in the sample. First, dry scrubbers at recirculating plants appear to consume more water than their wet counterparts. This result is based on a small plant sample (8 dry versus 37 wet scrubber plants with recirculating cooling systems). Further, these plants are relatively smaller: dry scrubbed plants produced, on average, about half as much electricity per plant as wet scrubbed plants for both recirculating and once-through systems. Second, lignite plants appear to show higher withdrawal rates but lower consumption for scrubbed plants, the opposite of what is observed for coal overall and the other two coal ranks individually. This might be a function of the particular plants involved, especially because there are only five unscrubbed lignite plants for analysis. Given lignite's typical sulfur profile, these plants likely operate differently from scrubbed lignite plants.

Once-through scrubbed plants are compared with once through unscrubbed plants, and similarly for recirculating plants. Note that given the relatively sparse data, in cases where scrubbed plants are not 100% wet or dry scrubbed, no adjustments are made to capture the remaining output of the plants (thus, the percentages do not sum). This decision is made because with the very small samples for this dataset, introducing assumptions about how scrubber hourly operation coincides with plant output by fuel type and other parameters for mixed-fuel, mixed-scrubber, and/or mixed-cooling system plants is considered undesirable.

As water use for flue gas desulfurization is accounted for in power plant water withdrawals and consumption on Form 923/860, estimated water use for sulfur removal is subtracted from estimated water use values for electricity conversion and reported separately.

Combustion

As a hydrocarbon, coal releases water alongside CO_2 when it is combusted. This water is an addition to the active hydrologic cycle, as the hydrogen is bound in the coal prior to combustion and is thus not participating in the active hydrologic cycle. Table S9 shows average estimated fresh water vapor production intensity and estimated H/C ratios for subbituminous, bituminous, and lignite coal. This can be considered production of surface water, which may fall as rain and either remain fresh or become part of the ocean.

Table S9. Water produced by combustion of coal

Coal Grade	Water produced, m^3/GJ combusted	Water produced, m^3/delivered GJ	Estimated H/C ratio	Estimated heat content	Estimated percent hydrocarbon
Subbituminous	0.03	0.10	0.75	20 GJ/tonne	90%
Bituminous	0.02	0.04	1	28 GJ/tonne	95%
Lignite	0.03	0.08	1	16 GJ/tonne	75%

Post-combustion solid waste handling

Unlike most other power plants, coal-fired power plants produce a variety of solid waste byproducts. These byproducts exist primarily as some form of ash, the component of coal that is not combusted when coal is burned, or as flue gas desulfurization (FGD) solids, sulfur-containing products that form after reaction with an alkaline substance like lime. Ash comprises both bottom ash, which remains in the coal furnace or falls into a hopper directly below, and the captured portion of fly ash, which escapes through the plant stack unless intercepted by equipment like an electrostatic precipitator or other particle filter. Some FGD solids are marketable as a gypsum substitute, while others are strictly a waste product.

Solid waste from coal-fired power plants demands water by one of two generic pathways. FGD solids are often generated as a solid-liquid mix due to the nature of wet scrubbing, where water is sprayed during the reaction and forms a slurry that usually needs to be dewatered. In the second pathway, solids are mixed with water for easier management and transportation as a solids-water slurry. Slurries are either impounded in disposal ponds, dewatered for landfilling, or, in the case of FGD gypsum, sold or used onsite as a useful product (EIA Form 923 8A)[1]. Additionally, dry solids that are not slurried are often moistened for dust control.

Total new water consumption and withdrawal associated with solid waste management at coal-fired power plants for 2014 is estimated based on assumptions about how much water is used per unit of waste coupled with data about the total amount of solid wastes generated in each category. (Water contained in existing ponds is not included.) This work assumes that all coal-fired power plant-derived solids reported as ponded on EIA Form 923 8A (about 12% by mass) are mixed with fresh water at a 20% solids / 80% water mass ratio (Senapati et al. 2010)[125], though dense slurries of around 60-65% solids by mass are being characterized globally for potential low-water ash disposal applications, especially in India due to high ash, low water contexts (e.g., Senapati et al. 2015, Bagchi and Mahore 2013, Abel Pump Technology 2015)[126–128]. All remaining solids reported on EIA Form 923 8A are assumed to be moistened for dust control at a 90% solids / 10% fresh water mass ratio (following Lam et al. 2010[129], noting beneficial removal of salts from MSW ash at about a 10:1 liquid to solid ratio). While water for slurrying and moistening need not be particularly clean (Zhai et al. 2011)[123], its quality and source almost certainly matches the quality and source of other water used at the power plants producing the solids, which is fresh. Using Form 923's plant-level resolution (associated with fuel type but not precise coal origin), these values are estimated separately for bituminous, subbituminous, and lignite coals as of 2014. As these water uses are reported in Form 923, estimated water use for solid waste handling is subtracted from estimated water use values for electricity conversion and reported separately, much like FGD water. We assume withdrawal equals consumption, in part because water clarification and recycling is common during sluicing.

We also note several points that might be useful to future investigators about the scope of this analysis. First, coal mining-related slurries associated with solid waste management at mines (e.g., for fines and waste rock) are captured in the mining analysis above (but are not explicitly analyzed). Mass to liquid ratios are likely similar, however, though the use of slurry disposal is widely variant across mines. Second, an estimate of 10% water to 90% solids by mass for non-ponded disposal is uncertain. When solids are landfilled post ponding, for example when a pond is drained and closed or when a wet bottom ash system is dewatered for disposal, slurries are drained to about 80% solids by mass, and sources note between about 8% and 17% moisture content for fly ash and 10% to 25% moisture content for bottom ash (EPA and TVA 1981, Morris 2011, Lessard et al. 2016, Bayar 2015)[130–133]. It is not clear how often solids that are listed as landfilled are dewatered versus moistened, but 10% water by mass is taken as an approximate estimate. Additionally, sources are often unclear about the basis for percentage figures offered (specifically, volume versus mass bases).

Finally, as mentioned above, this 2014 snapshot does not attempt to characterize and report the amount of water currently occupied by existing ash ponds. However, as of 2012, 735 active surface impoundments existed with an average surface area of over 50 acres and average depth of 20 feet (EPA 2016, FAQ #3)[134]. Assuming 80% water by mass, which translates to an estimated 85% water by volume based on ash density (FHWA 2016)[135], these figures imply about 7.7×10^{8} m^3 of water is currently in use for ash ponds—an order of magnitude more than we estimate is added annually to ash for all purposes. New EPA rules on coal ash that require stricter groundwater protection and attempt to close impoundments suggest this value will decline, as will ongoing volumes of water dedicated to slurrying (EPA 2017)[136].

Natural Gas

The natural gas fuel cycle withdraws and consumes water for extraction (including hydraulic fracturing and produced water), processing, pipeline transportation, and electricity generation. Natural gas use for industrial, residential, and commercial heating is typically air-cooled. Burning natural gas releases water as a combustion byproduct.

This work estimates that the US natural gas system consumes 7.4×10^{-2} m^3/delivered GJ of total water (8.2×10^{-1} m^3/delivered GJ total water withdrawn) through these four mechanisms based on a 2016 analysis, noting that the large increase in unconventional gas production from tight formations like shale starting around 2008 means that data vintage for natural gas extraction is highly relevant. Many of the steps in the natural gas fuel cycle are robust to relatively low water quality. Note that states control a significant portion of the regulatory process for oil and natural gas, so the data sets used in this work are generally either state-level analyses or aggregations thereof.

<u>Extraction</u>

The approach to estimating water volumes required for natural gas extraction is nearly identical to that used for oil (see the oil section). Allocation across surface, ground, and recycled water is based on the 2014 value of 4% for recycled water use in hydraulic fracturing (Chen 2016, pers. comm.) and a surface water to groundwater split based on values from Texas and Pennsylvania accounting for 67% of total unconventional natural gas production (Nicot and Scanlon 2012, Nicot et al. 2014)[22,137], rather than the Texas and North Dakota oil play-based split used for oil.

Drilling

Total US water volumes withdrawn and consumed for drilling natural gas wells are estimated based on an estimate of 0.7 L/GJ natural gas production, in turn estimated from 10 years of natural gas production in Texas (2000-2009) given relatively high quality pre-shale boom data (Grubert et al. 2012)[31]. This intensity factor is multiplied by total conventional and unconventional natural gas production to give an estimate for basic drilling water requirements in each case. Given the nature of the drilling process, no water is assumed to be returned to its original source, so withdrawals and consumption are the same. Note that this work uses a volume/energy estimate rather than a bore volume-based estimate or a volume/volume estimate in order to avoid making assumptions about the pressure of produced natural gas and because drilling footage is not available through centralized public sources post-2011, most notably EIA's Drilling Productivity Report (DPR, Lieskovsky and Gorgen 2013)[138].

Drilling water source and quality allocations are based on assumptions. First, the volume of recycled water used for drilling is estimated assuming that all oil and natural gas-related produced water used for beneficial reuse is used in drilling (at 0.6% of produced water, Veil 2015)[20], allocated between oil and natural gas wells based on Kondash and Vengosh (2015)[13]. All recycled water is assumed to be saline (though it might be treated to remove salts before reuse). The remainder of the drilling water is allocated to groundwater or surface water sources based on the ratio between groundwater and surface water sourcing for hydraulic fracturing water for unconventional wells in the Marcellus and Eagle Ford shale plays, accounting for 67% of 2014 unconventional production, at 65% groundwater to 35% surface water. While there is no clear evidence that water sourcing for unconventional wells is similar to that for conventional wells, this assumption is made for simplicity absent evidence otherwise. Further, this groundwater to surface water ratio is roughly similar to that for both domestic and agricultural water withdrawals and is thus deemed a reasonable estimate (Maupin et al. 2014)[9].

All groundwater and surface water used for drilling are assumed to be fresh given a lack of more specific data and a general decision throughout this work to conservatively overestimate the use of freshwater for the energy system when a choice is needed.

Multistage high volume hydraulic fracturing of horizontal wells

The approach to estimating water HF is largely the same as that used for oil; it is repeated with slight modifications on specific data for convenience here. Literature estimates for the water intensity of HF are much more recent than those for many other energy-related processes. This recency is due in part to the fact that the practice essentially did not exist commercially until about 2007 (EIA 2016, "U.S. Shale Production")[139]. As with oil, this work takes a production-weighted average based on Chen and Carter (2016)[21] based on analysis of data for over 80,000 wells hydraulically fractured in the US between 2008 and 2014, as a best-guess estimate for the total volume of water used for HF. Multiple literature estimates for the amount of water used for modern hydraulic fracturing exist (e.g., Grubert et al. 2012, Kondash and Vengosh 2015, Laurenzi et al. 2016, Scanlon et al. 2014, Shrestha et al. 2017)[13,15,31,140,141]. The Chen and Carter (2016)[21] values are used preferentially in this work given their recency and use of an extensive database. Numbers for annual water use for hydraulic fracturing based on Chen and Carter (2016)[21] are derived by multiplying values in that document's Table S2 (wells per state by year) by values in Table S5 (annual average water use per well by state by year) in the supplementary information. Allocation across surface, ground, and recycled water is based on the 2014 value of 4% for recycled water use in hydraulic fracturing (Chen 2016, pers. comm.) and a surface water to groundwater split based on values from the Eagle Ford Shale in Texas and the Marcellus Shale in Pennsylvania (Nicot et al. 2014)[22], which accounted for about two thirds of natural gas production from tight sources in 2014 (EIA 2015, Drilling Productivity Report)[19].

Produced water

As with drilling, produced water associated with natural gas is addressed similarly to that associated with oil. Again, the major data source used to estimate produced water volumes and fates is Veil's 2015 publication of 2012 estimates (Veil 2015)[20]. State-specific reported or estimated water-gas ratios (WGRs) are used in conjunction with 2014 natural gas production volumes by state to estimate 2014 produced water volumes. All produced water is accounted as a groundwater withdrawal, with quality allocated by state based on USGS maps of salinity (Harto and Veil 2011, Otton and Mercier, n.d.)[25,26]. Produced water is allocated to either unconventional or conventional natural gas production based on Kondash and Vengosh (2015)[13]. Given the tight nature of many unconventional reservoirs as of 2014, produced water volumes from unconventional reservoirs are considerably lower—both in total and in intensity—than from conventional reservoirs. Note, however, that the rapid rise of unconventional development means that increases in produced water volumes associated with new fields can be locally important, as in Pennsylvania (Engle et al. 2014, Veil 2015)[20,142]. Also, coalbed methane development, as observed in places like Alabama and Wyoming, tends to have very high water-gas ratios because of the need to dewater wells to liberate methane from the coal.

Consumptive use is estimated based on Veil (2015, Fig. ES-2)[20], assuming the ultimate fate of produced waters was constant between 2012 and 2014. As waterflooding is not routinely used for natural gas production, all natural gas-associated produced water is considered consumed through deep well injection or other methods. In practice, since about 20% of US natural gas was coproduced with oil in 2014 (EIA 2017, "Natural Gas Gross Withdrawals and Production")[30], there are likely cases where gas-allocated produced water is used for EOR.

As in the oil case, note that the values from Veil (2015)[20] include flowback from drilling and completions. See the section on oil for an explanation of why this is not regarded as double counting in this work. Also, as in the oil case, this work reiterates prior observations that data quality on produced water is poor, particularly given that there is no requirement to track volumes in some jurisdictions and that measurements are not always made using reliable tools (Clark and Veil 2009, Veil 2015)[20,33].

<u>Processing</u>

Natural gas is processed between its raw extraction from the ground and its injection into a pipeline, at which point it must meet specific quality requirements to be considered pipeline quality gas. Quality concerns are related to two major attributes: heat content (since consumers pay for energy based on volume) and corrosiveness (since pipelines can be damaged by corrosive elements). In general, this means that natural gas processing separates natural gas liquids (NGLs), or higher chain length hydrocarbons, from the gas; dehydrates the gas to remove water that could damage the lines; and, where needed, removes acid gases like CO_2 and H_2S (see e.g., EIA 2012)[143].

This work contributes a new estimate of the water intensity for natural gas, including separate estimates for conventional and unconventional gas, based on three main processing operations: dehydration for water removal, amine scrubbing for (primarily) CO_2 removal, and the Claus process for H_2S removal. The major processing-related difference between conventional and unconventional gas as defined in this work is that unconventional gas has much lower sulfur content on average (see e.g., Weiland and Hatcher 2012)[144]. Though some sulfur removal is required for unconventional gas (Weiland and Hatcher 2012)[144], this work makes the simplifying assumption that water use for sulfur removal from natural gas is allocated to conventional gas.

Despite some concerns about data quality (see below), the motivation for generating a new estimate for the water intensity of natural gas processing is that current literature estimates represent perhaps the best example of the problem of secondary citation in the water-energy literature. While this new estimate relies on some values of unknown original provenance, it is based on physical relationships (i.e., the amount of contaminant removed from the natural gas stream) and water intensity values taken from design handbooks (for sulfur, Parkash 2003)[145] and calibrated modeling outputs (for CO_2, Talati et al. 2014)[146]. By contrast, almost all published estimates for the water intensity of natural gas processing are based on a single source, a June 1979 article in the Oil and Gas Journal about startup operations at a dedicated sour gas processing plant in Southwestern Wyoming (White and Morgan 1979)[147]. This plant processed 60 mmscfd of sour gas, with 3.76 mol% H_2S and 17.56 mol% CO_2 content, using HiPure sweetening, dehydration and dewpoint control, condensate stabilization, a sulfur plant, and basic plant utilities. The article reports usage of 50 gallons/minute of raw makeup water for these processes, at an estimated water consumption of 0.16 L/m^3 or 0.006 L/GJ. Over the years, many papers have presented this value, often after several steps of unit conversion from the reported 50 gallons/minute, and usually via secondary citation. The end result is that the literature appears to contain multiple, independent, and recent estimates (e.g., Ali and Kumar 2016[148] Table 2, referencing four sources based on the White and Morgan 1979[147] value). Unit conversions and adjustment for significant figures make the estimates different enough that a reader could reasonably but incorrectly conclude that there is some variation in measurements, and these estimates converge on a single and apparently highly accurate estimate that increases confidence in the stability of the value. In fact, each estimate is a repetition of a single estimate that has been generalized from startup operations at one sour gas plant almost four decades ago.

In an effort to determine a more representative and updated value for water withdrawal and consumption for natural gas processing in the US, a variety of design documents, handbooks, environmental statements, and other sources were consulted. In addition, we contacted more than ten natural gas processing plant operators and several regulatory offices responsible for associated environmental assessments by email or phone. Most contact efforts were unsuccessful. However, one natural gas processing plant operator was willing to discuss plant water balance and explained that their water use is not gaged. That operator's sense was that most of the water handling at the plant was associated with either rain water or water that was being stripped out of the natural gas itself during dehydration—that is, water is removed from the natural gas rather than used in the process. Multiple regulators also responded (independently) and noted that in their experience, natural gas plants remove water from the gas stream but do not use water in the process, noting in one case that the plant was sufficiently isolated that any external water demand would have required hauling water. This information is supported by the fact that EIS documents for natural gas processing plants often include reference to relatively minor water requirements, such as for hydrostatic testing and dust suppression (BLM 2014, 4-41; BLM 2016, 2.2.8)[149,150], but not for plant operations. Given attention to other uses of water, this exclusion likely indicates that water is not always needed at gas processing plants. Indeed, a 1978 document (BLM 1978, p. 453)[151] notes that even at the time, "modern" gas processing plants were converting to fin-fan air cooling systems from older water-based cooling systems, which further supports the suggestion that some, and possibly most (see Mokhatab and Poe 2012, Ch. 9)[152] modern gas processing plants are not water-cooled.

Based on this investigation, water at natural gas processing plants is assumed to fall into two categories: 1) water recovered from the gas stream, and 2) process water for certain acid gas removal units, particularly those removing CO_2 and H_2S (Mokhatab and Poe 2012, Ch. 4 and Ch. 7)[152]. (When cooling water is referenced in this modern handbook on natural gas processing (Mokhatab and Poe 2012)[152], it is associated with power plants, not processing facilities.) While essentially all natural gas is dehydrated, acid gas levels vary by natural gas source. A modern natural gas processing handbook suggests that H_2S removal is required for about 25% of newly extracted natural gas (Mokhatab and Poe 2012, Ch. 8[152], though note there is no citation or date given for the 25% value). A new estimate for the water intensity of natural gas processing in the US is generated by estimating the water withdrawal and consumption associated with removing a given mass of contaminant (water, CO_2, or H_2S), comparing raw gas and processed gas composition to estimate the mass of each contaminant removed per unit of natural gas, and using 2014 production volumes to get an estimate for the total water used for processing in 2014. While this estimate is more general than the single plant-based value currently common in the literature, the value should be used cautiously given that the original sources of data on water requirements and gas composition are unknown.

Dehydration

Raw natural gas is saturated with formation water, and most of this water must be removed for the natural gas to meet pipeline specifications (Baker and Lokhandwala 2008)[153]. Glycol-based absorption systems are the most common method for removing water from natural gas

(Baker and Lokhandwala 2008)[153]. The total volume of water removed from the US natural gas system in 2014 is estimated by calculating the amount of water present per unit of raw natural gas, assuming that on average, water saturation tables for sweet gas can be used, subtracting the amount of water per unit of natural gas allowable in the pipeline system, and multiplying the difference by total natural gas production. Water removed from natural gas originated as formation water, so this dehydration water is assumed to be groundwater with a quality distribution identical to that of produced water. Further, it is assumed to be withdrawn and consumed like produced water. Absent better data, all water associated with dehydrators is assumed to be consumed via disposal to a non-original aquifer. Note that this choice is not straightforward, as the water must be actively separated from the natural gas and could theoretically be considered a net contribution of water. As volumes are small, the choice is not highly consequential, and allocating this water as produced water seems most consistent with the physical reality.

Overall, assuming saturation of about 830 lb/mmcf (Kidnay et al. 2011, Ch. 6)[154] for sweet gas at the reference temperature and pressure of 60ºF and 14.73 psia set by EIA and pipeline standards of 7 lb/mmcf (Mokhatab and Poe 2012, Ch. 9)[152], water withdrawal and consumption associated with dehydration is estimated at 0.3733 m^3/mmcf, or, assuming 25.6 GJ/m^3, 3.4×10^{-4} m^3 water/GJ natural gas dehydrated. This work assumes the value is the same for conventional and unconventional natural gas, as the estimate is based on natural gas saturation levels and pipeline standards that apply to both. One note is that conventional natural gas is more likely to contain higher sulfur levels (see below), so there is likely some variability in saturation level.

Acid gas removal

This investigation examines water requirements associated with two major acid gas removal processes: amine systems, which separate H_2S and CO_2 from the hydrocarbons in raw natural gas through Claus sulfur recovery systems, which chemically convert H_2S to elemental sulfur and water (Mokhatab and Poe 2012, Ch. 8)[152], and through contact with an aqueous amine solution for CO_2 and small amounts of H_2S (Mokhatab and Poe 2012, Ch. 7)[152].

Water use for H_2S removal in Claus sulfur recovery units is estimated based on Parkash (2003)[145], which details utility demands for these processes in a refinery context. Sulfur recovery is assumed to be similar in refineries and natural gas processing plant contexts. The original source of the reported water consumption data in Parkash (2003)[145] is not cited and is thus unknown (note, however, that when water volumes—reported in million imperial gallons—are converted to cubic meters, very round numbers result: this suggests that reported volumes might be highly approximate expert judgments). Based on feed composition (Table 8-2, Parkash 2003)[145] and water requirements for the Claus Sulfur Recovery Unit and tail gas treatment (Tables 8-3 and 8-9, Parkash 2003)[145], water consumption is estimated at 1,340 m^3/tonne of sulfur removed. Of this volume, 1,200 m^3 is consumed for cooling. The assumed consumption to withdrawal ratio is 0.9, and all other water uses are assumed to be fully consumed. All water is assumed to be fresh, and water is allocated to surface or groundwater sources based on the proportions of each in public water supply, or about 40% groundwater and 60% surface water (Maupin et al. 2014)[9]. In practice, some of this water is likely reuse from on-site dehydrator units and the minor volume of water generated during the Claus reaction, which produces about 0.56 m^3 freshwater per tonne of sulfur through the overall reaction of $H_2S + \frac{1}{2} O_2 \rightarrow S + H_2O$.

Water use for CO_2 removal in amine systems is coarsely estimated based on process simulations for carbon capture and storage at a coal fired power plant, which uses a similar approach, using the 2012 version of the Integrated Environmental Control Model (IECM) (Talati et al. 2014)[146]. That simulation finds a water consumption burden of about 2 m^3 water/tonne CO_2 removed and withdrawal of about 3 m^3 water/tonne CO_2 removed (based on Table 2: the 92.8 tons of cooling water per ton of CO_2 captured noted in the text is the total volume circulated, reflecting the fact that most of the water is cycled many times within the plant.) An earlier paper using the 2010 version of IECM (Zhai et al. 2011)[123] finds slightly lower water demand of about 1.3 and 1.8 m^3 water/tonne CO_2 removed of consumption and withdrawal, respectively, for a slightly larger power plant. Data from the mid-2000s used to estimate consumptive water demand for amine carbon capture systems at natural gas-fired power plants and pulverized coal-fired power plants, respectively, suggest approximately 1.4 and 2.1 m^3 water consumption/tonne CO_2 removed (Grubert et al. 2012, King et al. 2008)[31,155]. Given that amine-based power plant carbon capture systems are often scaled-up versions of those found at natural gas processing plants, the comparison is likely valid, but caution is advised. Plant scale and concentration of the CO_2 stream are likely to be major determinants of amine system water intensity.

The total amount of water associated with natural gas processing to remove H_2S and CO_2 is estimated by applying the above process factors to the estimated amount of H_2S and CO_2 removed from the natural gas system in 2014. The amount of sulfur removed is known directly, as the United States Geological Survey (USGS) tracks sulfur as a mineral commodity, including the specific amount removed from natural gas. In 2014, this was one million tonnes (Apodaca 2016, Table 3)[156]. Water withdrawals and consumption for sulfur removal (including the volumes produced via the Claus reaction) are allocated to conventional natural gas only, as unconventional natural gas is much less likely to have high sulfur levels. This choice is supported by evidence from sulfur production data, which shows that sulfur production from natural gas processing plants has dropped by about half since the mid-2000s (Apodaca 2017, repository for Annual Minerals Yearbook: Sulfur reports)[157], before shale gas production became common (EIA 2016)[158] (unconventional gas is now roughly half of US production, EIA 2017, Natural Gas Gross Withdrawals)[159].

The amount of CO_2 removed from natural gas is taken from the US 2016 Greenhouse Gas Inventory (EPA 2016, Table 3-49)[160], with 23.6 million tonnes of noncombustion CO_2 associated with acid gas removal units (AGR vents) at natural gas processing plants in 2014 (EPA 2016, Annex 3, Table A-152)[160]. Water withdrawals and consumption associated with CO_2 removal are allocated to conventional and unconventional natural gas proportionate to production levels, based on the assumption absent clear data to the contrary that average CO_2 content is similar.

Caution in using the EPA value for CO_2 emissions from acid gas removal units is suggested. The EPA's Greenhouse Gas Inventory estimates CO_2 removal based on an assumption of 3.45% CO_2 (assumed to be a volumetric percentage) in produced gas and 1% CO_2 in transmission quality gas (EPA 2016, Annex 3, Page A-202)[160], which in turn is based on a study from 2001—prior to the emergence of large volumes of shale gas, which might have different carbon dioxide content. Further, pipeline natural gas might have more than 1% CO_2, as suggested by a gas chromatography exercise showing about 1.5% CO_2 in commercial pipelines (Fuller n.d.)[161]. Note that data from another government source, the EIA's report of nonhydrocarbon gases removed from natural gas (EIA 2017, Natural Gas Gross Withdrawals)[159], suggest that total CO_2 removal from natural gas in 2014 was about 65% of the EPA value, at 15.5 million tonnes of CO_2 removed. This estimate is derived using ideal gas law approximations to estimate the volume of

H_2S associated with removed sulfur, knowledge of the amount of helium removed from the natural gas system in 2014 (USGS 2016, p 78)[162], and assuming nitrogen removal is negligible (see e.g., Baker and Lokhandwala 2008[153] for evidence that it is small). The choice to use the EPA value despite reservations about data quality is made because EIA data is voluntarily reported, preliminary for 2014 at the time of this writing, and not specific to carbon dioxide volumes. Further, specific fields can have large impacts on the stability of the EIA number, such as the Bravo Dome, which is a CO_2 field included in the EIA volumes (EIA 2017, Kinder Morgan 2015)[159,163]. Future users should recognize that estimates based on water intensity per unit of sulfur and CO_2 (which are themselves highly uncertain) are likely more reliable than water intensity per unit of natural gas because of changing gas compositions.

Transportation

Pipeline transportation

The vast majority of natural gas, both pre- and post-processing, is transported by pipeline in the US. Pipeline transportation represents a minor withdrawal and consumption of freshwater in the US, primarily via hydrostatic testing that involves first washing, then pressurizing a pipeline with water to test its strength. This analysis uses natural gas pipeline data regarding pressure testing intervals, pipeline mileage, and pipeline diameter from the Pipeline & Hazardous Materials Safety Administration (PHMSA) and reported water withdrawal and consumption values for pipeline pressure testing at Pacific Gas and Electric (PG&E) to estimate total freshwater intensity for pipeline transportation.

Hydrostatic testing is a form of strength testing that pipeline operators use to evaluate the integrity of the pipelines. Based on fatigue curves and conservative safety factors, one major operator internally recommends testing every 50 years (pers. comm., 2015). PHMSA data for natural gas pipelines show that about 0.6% of all transmission and gathering mileage (also about 0.6% if tests are assumed to be carried out on transmission mileage only) was pressure tested in 2014 (PHMSA 2017, Gas Transmission & Gathering Annual Data – 2010 to present)[37]. Data on the age of the tested pipelines are not available, but the total tested mileage is approximately 2% of the total transmission pipeline mileage built before 1960 or at an unknown date, so a 50-year target return period is plausible (PHMSA 2017)[37]. Note also that hydrostatic or pressure testing is not the only method operators use to strength test pipelines: direct assessment and in-line inspection methods are also used (PHMSA 2011)[164].

This analysis makes several assumptions. First, it assumes that transmission pipelines of any diameter are equally likely to be tested. Second, it assumes that distribution and gathering pipelines are not hydrostatically tested after pre-commissioning. This assumption is supported by the facts that distribution pipelines operate at lower pressure than transmission pipelines, PHMSA does not collect data on pressure tests for distribution lines (PHMSA 2017, Gas Distribution Annual Data – 2010 to present)[37], and major operators report pressure test data for transmission but not distribution lines (e.g., PG&E 2015)[40]. Since pre-commissioning water use represents embodied water rather than operational water, it excluded from analysis but is estimated to be small relative to hydrostatic test water for several reasons: distribution pipelines are much smaller in diameter than transmission pipelines, which means distribution pipelines have lower volume per mile; annual pipe mileage changes are small (negative for transmission and gathering and less than 1% for distribution, PHMSA 2017, Pipeline Mileage and Facilities)[35], with annual replacement mileage also typically small); and the need for pre-service hydrotests given in-line inspection tools and pneumatic alternatives is questioned (see e.g., Kirkwood and Cosham 2000)[165]. Third, this analysis assumes that all mileage reported as "inspected by pressure testing in calendar year" (Part F3A on the PHMSA Gas Transmission and Gathering Pipeline Annual Form, PHMSA 2017, Gas Transmission & Gathering Annual Data – 2010 to present)[37] is hydrostatically tested. In practice, some of this mileage is likely to be tested using air or other fluids.

Water withdrawal and consumption for hydrostatic pipeline pressure testing are estimated in two steps. First, the water needed for the test itself is estimated based on the volume of the pipe, as the hydrostatic test consists of completely filling the pipe with water and pressurizing to the desired level. That is, the volume of water needed for the hydrostatic test is equal to the volume of the pipe being tested. This value is estimated using PHMSA information about pipeline mileage and diameter (PHMSA 2017, Gas Transmission & Gathering Annual Data – 2010 to present)[37]. As pipeline mileage is recorded in pipeline classes, the upper end of the interval for pipeline diameter is used for a conservative estimate of size.

The second estimation step uses PG&E's 2014 self-reported hydrostatic test-associated water consumption and withdrawal values alongside its PHMSA-reported pressure-tested mileage (not the same as its strength-tested mileage, PG&E 2015)[40] to estimate the amount of additional water required for pipeline washing, retests, and other values not captured based on the pure volume method. PG&E has a very large pipeline system, accounting for about 3.5% of total combined natural gas transmission/gathering and distribution mileage (PHMSA 2017, Pipeline Mileage and Facilities)[35] and is thus considered a reasonable proxy for estimating typical practice for hydrostatic testing. Comparing PG&E's reported 2014 values with estimates of test-only water use based on the PHMSA ratios implies that total withdrawals associated with hydrostatic testing are about four times test volumes (PG&E 2015)[40]. Consumption is estimated at 0%: PG&E reports consumption for dust control and irrigation, which is not considered pipeline-associated consumption (PG&E 2015)[40].

Pipelines are subject to corrosion concerns that would be exacerbated by nonfresh water, so all test and wash water is assumed to be fresh. Absent higher resolution data, hydrostatic test water is assumed to be drawn from public supply, at about 60% surface water and 40% groundwater (Maupin et al. 2014[9], and note that the irrigation water source ratio is similar). Water is sometimes reused within the system for additional hydrostatic tests (PG&E 2015)[40] when logistics allow, but this is not considered a withdrawal of reuse water because it is internal recycling rather than external reuse. Estimated freshwater use for the US natural gas pipeline system as of 2014 is 770 million gallons of withdrawal. Based on the volume of natural gas transported in the transmission pipeline system, water withdrawal intensity is estimated at 8.2×10^{-5} m^3/transported GJ (8.0×10^{-5} m^3/produced GJ), or 1.3×10^{-4} m^3/delivered GJ. This new estimate is slightly lower than literature estimates of about 1.1×10^{-4} m^3/produced GJ (Gleick 1994, and re-cited in Ali and Kumar 2016, Clark et al. 2013, Grubert and Kitasei 2010, Meldrum et al. 2013)[3,6,122,148,166]. If the signal is real, possible reasons for the decline include increased use of non-hydrostatic test methods for evaluating pipeline condition, including in-line inspection (e.g., pigging) and direct assessment methods.

LNG transportation

LNG tankers delivering gas require ballast water after unloading. Like oil tankers (NRC 1996, Ch. 2)[42], LNG vessels generally carry cargo in only one direction and thus require additional weight during their empty return voyages for safety. Based on ABS (2004, Table 2)[43], ballast mass replacement for cargo is estimated to be between about 30 and 50% of deadweight tonnage (DWT) for LNG vessels. Based on Qatargas' existing LNG fleet, about 93% of DWT is associated with LNG cargo (Qatargas 2014)[167], so ballast water is estimated (using the midpoint) at 37% of LNG tonnage. (Note that values in the DEIS for Oregon LNG (FERC 2015)[61] suggest necessary mass replacement at about 80% of LNG mass; other EIS estimates are much lower.) Given imports of about 70 million GJ in 2014 (EIA 2017, U.S. Liquefied Natural Gas Imports)[168], total water ballast requirements for LNG are estimated at 0.07 million m^3, or 1.1×10^{-4} m^3/GJ of imported LNG. This water is assumed to all be surface seawater. While it could be argued that the ocean is a single originating water body, given concerns about e.g., invasive species being transported to nonnative environments through ballast water (NRC 2004)[169], ballast water is accounted as a consumptive use as it is discharged distant from its origin upon ship reloading.

Storage

Natural gas is stored in depleted fields, aquifers, or salt caverns (EIA 2017, Underground Natural Gas Storage Capacity)[48]. This work assumes no additional water use for depleted field and aquifer storage (though water for hydrostatic testing and cleaning is likely required). Though formation water is displaced by natural gas during storage in depleted fields and aquifers, this work assumes that the water does not need to be removed. This assumption is supported by the fact that natural gas is compressible and that higher pressure in the storage formation is desirable for reextraction. Storage in salt caverns requires the use of water for solution mining to dissolve the salt.

While salt cavern construction requires a relatively large amount of water to dissolve the salt (see e.g., DOE 2006)[4], ongoing direct water withdrawals and consumption for storage are mainly associated with preventing creep, or closure due to salt movement. As of 2014, the US had about 700 Bcf of storage capacity in salt caverns, accounting for about 8% of total natural gas storage capacity (EIA 2017, Underground Natural Gas Storage Capacity)[48]. This 2014 value is about 48,000 mmcf higher than 2013 values, so this work assumes that 2014 water use for natural gas storage in salt caverns includes solution mining for both maintenance volumes and some new capacity. Note that capacity changes year over year are inconsistent, so water intensity numbers derived for 2014 are not generalizable.

As with oil storage in salt caverns, this work uses a study of the largest SPR site, Bryan Mound, to estimate annual closure rates due to salt creep at about 0.06% of volumetric capacity (Sobolik and Ehgartner 2009)[50]. While this estimate is based on specific salt characteristics that are unlikely to translate directly to all salt storage caverns, it can be used to roughly estimate water use for salt cavern storage. Given a total natural gas salt storage capacity of about 700 Bcf of natural gas, and assuming annual closure similar to that observed at Bryan Mound, maintenance solution mining is estimated at about 440 mmcf of storage space per year. In addition, new storage of 48,000 mmcf is assumed. Note that it is not clear whether the use of mmcf in this context refers to actual physical volume or to the amount of natural gas at reference conditions that can be stored; this work therefore assumes it is the amount of natural gas at reference conditions that can be stored. Assuming approximate water requirements of 500-600 gallons per mmbtu of natural gas storage (DOE 2006, p. 60)[4], and assuming energy density for marketed natural gas of 1116 mmbtu/mmcf in 2014 (EIA 2017, Table A4 Approximate Heat Content of Natural Gas)[170] and 1.055 GJ per mmbtu, this storage space requirement translates to about 110 million m^3 of freshwater withdrawal and consumption in 2014. The amount of natural gas actually stored in that capacity in 2014 is unknown.

Liquefied natural gas conversion

Liquefied natural gas (LNG) is natural gas cooled below its boiling point (-160 degrees C), usually to facilitate transportation in a compact form (about 600 times more volumetrically dense than pipeline gas). Since LNG is a more highly processed form of natural gas, not a distinct product, the additional water associated with LNG is attributable to two general processes: 1) liquefaction (cooling), which also requires additional processing to remove impurities, and 2) regasification (heating).

Liquefaction As of this writing, one export facility is operating at limited capacity in Sabine Pass, Louisiana (Cheniere Energy 2016)[171] and several more are permitted or proposed (FERC 2017)[172]. Major uses of water associated with liquefying natural gas are for pretreatment to remove impurities and for cooling itself. Pretreatment is required because pipeline quality natural gas is not sufficiently pure for liquefaction. The goal of processing is essentially the same as for natural gas processing, but with tighter limits on acid gas and particularly water content. Since water freezes well above natural gas' freezing point, water in the gas leads to solids formation during liquefaction. Thus, natural gas must be extremely dry for liquefaction. After this pretreatment, the gas is cooled to -160 degrees C, which sometimes uses air cooling (FERC 2014, p. 4-27)[173] and sometimes uses water cooling (FERC 2015)[61].

This work uses two Environmental Impact Statements (EIS) for proposed export terminals in the US to estimate water intensity associated with LNG preparation at export terminals. One EIS includes water for pretreatment only (the facility is otherwise air cooled), which enables an estimate of 6.9×10^{-5} m^3/GJ LNG for pretreatment (FERC 2014)[173]. This value is assumed to be for both withdrawal and consumption, and the water is assumed to be fresh. Some of this water is sourced from the dehydration process: that is, some water is taken out of the natural gas and used in the process. Note that this value is about 50 times smaller than would be expected based on the water intensity per tonne of CO_2 removed estimated in the processing section, assuming that processing for pipelines takes CO_2 content from 3.45% to 1% and processing for LNG takes CO_2 content from 1% to 0%. Explanations could include: CO_2 removal in gas processing plants is more water efficient than in derivative power plant processing units (perhaps because different processes are used for these much lower CO_2 concentrations), that natural gas processing units recapture more of the evaporated water, that some CO_2 removal occurs during cooling given CO_2's higher boiling point relative to methane, or that the Freeport pre-operational estimate is not representative. The most likely explanation is that when the feed gas is already pipeline quality, with about 1% CO_2 content (molar), low-water adsorption or membrane processes are used instead of amine processes (see e.g., Molecular Gate 2016)[174].

Assuming this estimate for pretreatment is consistent across facilities, which is a reasonable assumption given that pipeline and LNG quality standards are consistent in the US, data from the Oregon LNG DEIS (FERC 2015)[61] suggest that wet cooling during the liquefaction process requires about 1.9×10^{-2} m^3/GJ LNG of water withdrawals and 1.2×10^{-2} m^3/GJ LNG of water consumption. This water is assumed to be fresh, as these values are derived from estimates of impact to the Columbia River rather than the ocean (FERC 2015)[61]. The Oregon LNG DEIS also includes data that imply water withdrawals for LNG export ship cooling at about 1.1×10^{-4} m^3/GJ LNG while the ships are in port (FERC 2015, Section 4.1.3.2)[61].

Regasification Regasifying LNG for use or further transportation through pipelines primarily requires heating the gas. At some import facilities where regasification is performed, seawater is used as a heat source (Franco and Casarosa 2014)[175]. Given that heating the LNG cools the seawater, all use is assumed to be withdrawal with no evaporative consumption. Boilers, air heating, and co-location with industrial processes requiring a cold source are also used for regasification (e.g., Franco and Casarosa 2014)[175]. Based on available Environmental Impact Statements (EIS) for the twelve LNG import terminals operating as of early 2017 (FERC 2017, Existing)[176], it appears that most, if not all, US terminals use methods other than open-loop seawater heating for regasification. The EIS-based suggestion that open loop seawater heating is unusual in the US is supported by the fact that such heating is assumed to kill any marine life entrained in the system and to create thermal plumes. Alternatives appear to usually be closed loop systems with natural gas heating. NPDES and EIS documents suggest continued water use on the order of 10^{-6} m^3/GJ for a 40-year-old plant (EPA 2010)[177] to 10^{-8} m^3/GJ for a new plant (FERC 2016)[178]. Compare this with one literature value for withdrawals associated with open loop seawater heating, at about 9.7×10^{-4} m^3 water/GJ regasified (Eisentrout et al. 2006)[179]. More significant is the water used for ballast in LNG ships, discussed in the transportation section.

Conversion

Power generation

Please see the section on Thermoelectric Power Generation for details on the calculation of water use at natural gas-fired power plants.

Combustion

As a hydrocarbon, natural gas releases water alongside CO_2 when it is combusted. On average, combusting natural gas produces about 0.047 m^3 of fresh water vapor/delivered GJ of natural gas. This estimate assumes an average H/C ratio of four, given methane's chemical formula of CH_4. This combustion water is accounted for as produced surface water, which may fall as rain and either remain fresh or become part of the ocean. For simplicity, this analysis accounts for the water as fresh, as it is fresh when produced.

Direct boiler use

The direct use of natural gas in non-power generating boilers, most notably for heating, is assumed to require no direct water consumption or withdrawal, as most of these processes are air-cooled.

Uranium

The uranium fuel cycle (comprising the US nuclear power fuel cycle) consumes freshwater through mining, milling, multiple fuel conversion steps, enrichment, power generation, and spent fuel handling mechanisms. This work estimates that US uranium-powered energy systems consume 0.6 m^3/delivered GJ (0.5 m^3/GJ of freshwater and 0.1 m^3/GJ of non-freshwater) and withdraw 26 m^3/delivered GJ of total US water (19 m^3/GJ of freshwater and 7 m^3/GJ of non-freshwater). This analysis might overestimate the ratio of freshwater to non-freshwater used in the uranium fuel cycle, as data on quality are not readily available for many non-power plant uses. Note that this analysis investigates the uranium fuel cycle related to civilian energy, not weapons.

A particular caution about applying intensity figures to the uranium fuel cycle is that the uranium fuel cycle is highly international. While the scope of this work is water use in the United States in 2014, it should be noted that the proportion of activity supporting US use of nuclear fuels for electricity generation that takes place in the US varies substantially by stage of the nuclear fuel cycle. Intensity figures, therefore, should be cautiously applied, as the energy basis for each stage is different. That is, the total thermal GJ involved varies by stage of the uranium life cycle (mining, conversion, enrichment, assembly, and power plant use). See Data File S1 for a summary of the energy basis for each stage.

<u>Extraction</u>

As of 2014, uranium is extracted at eight in-situ leach (ISL, also known as in-situ recovery, or ISR) facilities, two underground mines, and one mill processing waste sources in the United States (EIA 2016)[180]. The number of uranium production facilities active in a given year is not stable: in 2009, a recent high of 14 underground mines and a recent low of four ISL facilities were operating (EIA 2016)[180]. ISL facilities produce uranium-containing solutions that are processed into uranium concentrate (U_3O_8) on site. Underground mines produce uranium ore that must be milled into U_3O_8. White Mesa Mill (which extracts usable uranium from waste sources) produces uranium concentrate (U_3O_8) directly (Energy Fuels 2016)[181].

ISL facilities withdraw and consume water during drilling, production, and remediation. Drilling water use is assumed to be similar to drilling water use for other well types, like oil, natural gas, and geothermal, given the use of standard rotary mud drilling for uranium (NRC 2009, 2-11)[182]. Uranium is produced by injecting a freshwater-based acid or alkaline lixiviant (leach solution) into wells in a wellfield to dissolve uranium: US operations use alkaline lixiviants (Mudd 2001, as cited in Gallegos et al. 2015's recent review)[183,184]. During operations, ISL facilities maintain negative reservoir water balance in order to assure that any contaminants flow toward production wells (NRC 2009, 4.2-11)[182], employing a one to three percent production bleed to ensure negative balance that represents a consumptive use of groundwater (NRC 2009, 4.2-21)[182].

Restoration and remediation of ISL facilities consumes more water than operations. This use is because uranium leaching also liberates other compounds in the mining zone groundwater, so remediation is carried out via techniques like groundwater sweeping, reverse osmosis (RO), and reinjection. Groundwater sweeping refers to removing multiple pore volumes of water from the affected area and allowing uncontaminated groundwater to flow into the area, which is water intensive and often insufficient relative to more treatment-focused methods, such as RO after a single pore volume sweep. During a sweep, 100% of water is consumed; during the RO phase, about 70% of the water is returned (NRC 2009, 4.2-26)[182].

Wells are typically hundreds of meters deep and in confined aquifers (NRC 2009, 4.2-17)[182], so some withdrawn water is likely otherwise inaccessible and could be classified as production; however, water wells can be that deep, and the stated potential to draw down groundwater means that this work conservatively overestimates water use by assuming such pore dewatering and discharge is consumptive use of fresh groundwater. This assumption is supported by the discharge, evaporation, or land application of treated ISL wastewater and by comments in the Generic Environmental Impact Statement (GEIS) that ISL operations could lower water levels in local wells (NRC 2009, 4.2-21)[182].

Like other extractive activities, uranium mining uses water in quantities that do not consistently scale with production but are rather related to geology, groundwater conditions, and other depositional factors. This work uses reported experiences at specific mines alongside generic parameters about mine life from the GEIS to estimate water use for uranium extraction (NRC 2009)[182]. All such use is categorized as fresh groundwater consumption.

Drilling

Wells are drilled for uranium extraction for two major purposes: exploration and development. In 2014, 1,752 wells were drilled, with an average depth of about 740 feet. This activity level is the lowest in at least a decade, down from over 11,000 wells in 2012 and about 5,200 wells in 2013 (EIA 2016)[180]. This work estimates water used for conventional mud-based rotary drilling using the assumption from Scanlon et al. (2014)[185] that drilling water use is approximately six times the volume of the bore and the assumption that uranium wells are drilled with an average diameter of 11 cm (4.3 inches) (Ward 1983, IAEA 2001)[186,187]. In 2014, drilling uranium wells consumed about 23,000 m^3 of water—about 4% as much as was used to drill geothermal wells, one thousandth as much as was used to drill natural gas wells, and one fourth of one thousandth as much as was used to drill oil wells. Water intensity for uranium well drilling is estimated at 57 m^3/km. Estimating water intensity of drilling wells on an energy basis is inappropriate using only one year of data, as exploration and development drilling for uranium is not in steady state. That is, the amount of drilling in any given year does not correlate well with the amount of production in that year. For example, 2014 drilling and production suggest a water-per-energy intensity of 2.6×10^{-5} m^3/GJ of uranium produced via wells, while data from 2012, a recent high drilling year, suggests intensity of 1.8×10^{-4} m^3/GJ—seven times the 2014 estimate. A more realistic estimate is given by a five-year energy-weighted average of 1.1×10^{-4} m^3/GJ produced via wells from 2010-2014 (Energy Fuels 2015, EIA 2016)[180,188]. Caution is again advised in carefully tracking the energy basis: using the total US extracted energy or total US U_3O_8 production from milling facilities (EIA 2016)[180] suggests a five-year energy-weighted average drilling water intensity of 8.4×10^{-5} m^3/GJ and 8.5×10^{-5} m^3/GJ, respectively.

In situ leach facilities

We make several literature based assumptions about ISL facilities to estimate water intensity: specifically, production lifetimes of 15 years (NRC 2009, 2-45)[182], groundwater sweep periods of 1 year, aquifer restoration periods of 10 years (NRC 2009, 2-45, 4.2-26)[182], production bleed of 2%, and, in line with the hypothetical posed by the Nuclear Regulatory Commission's GEIS, that groundwater sweep consumes water at ten times the rate and aquifer restoration at 2.9 times the rate of water consumption due to production bleed in the production phase (NRC 2009)[182]. Data from Crow Butte ISL mine show 16,200 L/min withdrawals during production phase (NRC 2009)[182] and roughly 800,000 lb U_3O_8 production in 2007 (Cameco 2016)[189], implying an overall water intensity of 3.5×10^{-3} m^3/GJ fuel for a light water reactor, or 1,690 L/kg U_3O_8, taken as the best-guess estimate in this work. Estimates in Nicot et al. (2011)[101], including two operating ISL facilities and two inactive facilities in reclamation, imply an overall water intensity of 4.3×10^{-3} m^3/GJ (2,090 L/kg U_3O_8), taken as the high estimate in this work. Notably, using the midpoints of the NRC permitted pumping rates and permitted production capacity suggests a much lower intensity of 1.15×10^{-3} m^3/GJ, taken here as the low estimate.

Mining and milling

As of 2014, the majority (~80%) of US-produced U_3O_8 is produced from ISL facilities (EIA 2016, Energy Fuels 2015)[180,188]. The remainder is milled at White Mesa Mill in Utah, which as of 2014 takes ore from two underground mines and various sources of alternate feed material (Energy Fuels 2015)[188]. Ore containing approximately 0.3 million pounds U_3O_8 was produced from two mines in 2014 (EIA 2016, Energy Fuels 2015)[180,188]. White Mesa processed 0.55 million pounds of U_3O_8 from this ore and additional ore stock piles in addition to 0.39 million pounds of U_3O_8 from alternate feed material in 2014 (Energy Fuels 2015[188], converted from tons of ore). This work assumes that most water use associated with conventional mining and milling is associated with the milling process and thus calculates water consumption associated with non-ISL U_3O_8 production based on the output of White Mesa.

One comment is that alternate feed material takes many forms, so it is not clear whether such material is more or less water intensive than conventional ore. Data on White Mesa Mill's water consumption and discharges are not available from e.g., NPDES permits or Environmental Impact Statements. Thus, water intensity is calculated based on 2014 GRI data from Cameco, a major North American uranium producer that operates several underground mines and a large mill in Canada, noting that Cameco's ore grades at Key Lake (the mill) are substantially higher than those at White Mesa (Cameco 2014)[190]. Assuming the best-guess water intensity for ISL production as detailed above for the ~25% of Cameco's 2014 production coming from ISL, 2014 water withdrawals and consumption for mined uranium are estimated at 3.8×10^{-3} m^3/GJ and 3.4×10^{-4} m^3/GJ of production, respectively (Cameco 2014)[190]. Note that returns to surface water might not be returned to the original basin (e.g., if it originated as groundwater), which would make this consumption estimate an underestimate. This water is all considered to be fresh; Cameco uses both surface and groundwater, and based on the location of US mines, water used for US mining is assumed to be groundwater.

An additional low estimate is provided by the water intensity calculated from Mudd's evaluation of water intensity at major uranium extraction facilities, or 1.7×10^{-3} m^3/GJ (assumed to be both consumed and withdrawn) (2014)[191]. This value is based on diverse operations (including both underground and surface mines and one ISL facility), with ore grade varying from 0.03-4% U_3O_8, compared with the production-weighted average of 0.55% seen at US mines in 2014 (calculated from Energy Fuels 2015)[188].

Processing

As of 2014, White Mesa Mill is the only milling facility operating in the United States. The eight ISL facilities (EIA 2016)[180] and mill produce uranium concentrate in the form of U_3O_8, as described in the mining section above. This U_3O_8 concentrate is fluorinated and converted to uranium hexafluoride (UF_6) at one US facility, then enriched in the radioactive isotope U^{235} to levels of about 4% (versus typical natural concentrations of about 0.7%) at two US facilities. Post-enrichment, UF_6 is converted to UO_2 for assembly into fuel rods for use in nuclear power plants at three facilities and for use in nuclear submarines at two additional facilities. Depleted UF_6, or DUF_6, is deconverted to more stable compounds for disposal at two former enrichment facilities.

UF_6 Conversion

US conversion from U_3O_8 concentrate to UF_6 takes place via dry fluoride volatility processing, which is unusual: non-US converters use wet processes (World Nuclear Association 2016)[192]. All US conversion at this stage takes place at a single facility, the Honeywell Uranium Hexafluoride Processing Facility in Illinois, which has a nameplate capacity of 15,000 tonnes U (as UF_6) and an estimated capacity factor of 70% (Honeywell 2015, World Nuclear Association 2016)[192,193]. Water withdrawal is estimated at 5 million m^3 per year, or 1.9×10^{-3} m^3/delivered GJ, based on a central estimate from the Environmental Assessment's low and high operating requirements, which is similar to 2004 average discharges (NRC 2006)[194]. As water is primarily used for process water, pollution controls, cooling water, laundry water, and sanitary waste water, the close match between operating requirements and discharge volumes is logical (that is, most water is not being evaporated or incorporated into products). Discharge as of 2015 is about 10% higher than the central estimate in the EA, based on NPDES permit records (IEPA 2015)[195], which might be due to the fact that discharges include storm water. All withdrawals are recorded as consumption, as the source is onsite groundwater wells while the discharge is to the Ohio River, a surface water body. While non-fresh water could be used for applications like cooling and possibly others, freshwater is likely required for process uses.

UF_6 Enrichment

UF_6 is enriched from natural uranium levels (~0.7% U^{235}) to low-enriched uranium (LEU) levels (~4% U^{235}) at one plant in the United States as of 2014: a gas centrifuge plant known as the National Enrichment Facility or Urenco USA (the gaseous diffusion plant in Paducah, Kentucky, was closed in 2013) (NRC 2016)[196]. All water withdrawals for the National Enrichment Facility are classified as fresh groundwater consumption, as water is taken from the Ogallala aquifer via local municipal systems and not returned (NRC 2009)[182]. Water intensity is calculated per unit of thermal energy used in US nuclear power plants based on plant heat rate (EIA 2015)[197] and domestic fulfillment of 29% of enrichment needs in 2014 (EIA 2016)[198] down from 62% in 2012 (EIA 2013)[199] due to the closure of the Paducah facility.

UO_2 Conversion and Fuel Fabrication

Enriched UF_6 is converted to UO_2 in preparation for fuel fabrication via one of two major processes: the Integrated Dry Route (IDR, or dry) and the Ammonium Diuranate (ADU, or wet) processes (World Nuclear Association 2016)[192]. The United States has five fuel fabrication facilities that perform this conversion (NRC 2016)[196]. The Westinghouse Columbia Fuel Fabrication Facility (CFFF), Areva NP, and Global Nuclear Fuels-Americas (GNF-A) produce LEU for commercial power generation via either the ammonium diuranate (ADU) wet conversion process (CFFF) or the Integrated Dry Route (IDR) dry process (Areva NP and GNF-A) (NRC 2010)[200]. The other two facilities, both part of Babcock and Wilcox' Nuclear Operations Group, produce HEU for the US Navy using multiple processes (BWX Technologies, Inc. 2016, NRC 2010)[200,201].

Water use for these conversion and fabrication facilities is derived from environmental reports and assessments, supplemented with NPDES permit data where needed (since NPDES permits present data on discharges only and usually include storm water, information from process overviews is preferred).

DUF_6 Deconversion

Depleted UF_6 (DUF_6) is deconverted at two former gaseous diffusion enrichment sites, the Paducah and Portsmouth facilities, which are expected to deconvert 700,000 tonnes of U over 15 to 20 years with capacities of 18,000 tonnes U/yr and 13,500 tonnes U/yr respectively (NRC 2016a, World Nuclear Association 2016)[192,202]. This analysis is not considering the water use of Aerojet Ordnance Tennessee as strictly energy-related, as the DUF_6 is being used as a metal input. International Isotopes has not built or operated its proposed deconversion facilities as of 2014 (International Isotopes 2016)[203].

<u>Conversion</u>

Power Generation

Please see the section on Thermoelectric Power Generation for details on the calculation of water use at nuclear power plants.

Ship Conversion

As for oil-fired ships, nuclear-powered ships and submarines require cooling water. This work does not attempt to estimate US-based withdrawals and consumption of seawater used to cool these ships but notes the use for completeness. In 2014 and as of this writing, all American nuclear-powered ships are military ships, though one experimental nuclear-powered cargo ship was launched in 1959 as part of the Atoms for Peace initiative and decommissioned in 1972 (Freeman 2009)[204].

Waste Management

Spent fuel pools at nuclear power plants consume water to cool the still-hot spent fuel rods. Water use at these pools is estimated based on specifications for the AP1000, a 1117 MW-e reactor with minimum makeup of 35 gal/min (Westinghouse 2011)[205], and NRC regulations that stipulate makeup water system capacities must exceed the largest of several conditions, including the evaporation rate necessary to remove 0.3% of rated thermal reactor capacity (NRC 2007)[206]. These estimates are taken as the lower and upper bounds of water use at spent fuel pools: AP1000s are new, efficient plants (none exist in the US), and mandated system capacity is likely to exceed system use. Notably, it is possible that evaporative loads are well below circulation requirements, so the estimate derived here might be significantly inflated, but it is presented as a conservative estimate for water use for fuel cooling. Over 40,000 tonnes of spent fuel are stored in these on-site pools (Andrews 2004)[207].

In addition to these on-site pools, there is one away-from-reactor Independent Spent Fuel Storage Installation (ISFSI), the GE-Hitachi Morris Operation, which consumes an annual average of 1,630 L/day for storage of about 675 tonnes of spent fuel (NRC 2004, Andrews 2004)[207,208], much of which has been in place for decades and is thus fairly cool. Water intensity estimates per tonne of stored spent nuclear fuel for on-site versus Morris Operation spent fuel pool storage differ by a factor of about 200: while this factor seems very high, it is plausible given that Morris Operation fuel needed to be cool enough to transfer when it was emplaced between 1972 and 1989 (NRC 2004)[208], while on-site storage generally includes much hotter rods. The other 63 ISFSIs operating in the US as of 2014 are dry storage facilities using casks (NRC 2014, 2-15)[209]. These facilities can represent significant local water use during construction (mainly for concrete; see plans for a yet-unbuilt dry storage facility, NRC 2001)[210] but such water consumption is considered indirect and is thus out of the scope of this work.

Hydropower

Hydropower facilities consume freshwater through evaporation and seepage from reservoirs. This work estimates that US hydropower consumes 2.6 m^3/delivered GJ of freshwater through these two mechanisms (1.8 m^3/GJ from evaporation and 0.84 m^3/GJ from seepage). Water withdrawal for hydropower is estimated at 2.3×10^4 m^3/delivered GJ. US hydropower facilities are all on freshwater systems, so water quality consumed and water quality required are both fresh. Further discussion and models can be found in Grubert (2016)[211].

<u>Evaporation</u>

Conventional hydroelectric dams draw upon the potential energy in impounded water behind a dam for electricity consumption. Such impoundments increase the surface area of water bodies exposed to solar input relative to pre-dam rivers, which results in evaporation losses from the water body. This work makes two definitional assumptions to estimate evaporative water consumption associated with United States hydropower in 2014: first, that evaporation from impoundments whose primary use is hydropower is allocated to hydropower as consumptive use, while evaporation from impoundments whose primary use is something other than hydropower—even if the associated dam produces electricity—is not; and second, that net evaporation is the metric that defines consumptive use for hydropower. That is, only the water that evaporates from a reservoir surface that exceeds the amount of water that would have evaporated from the land without the reservoir, for example from a forest, is counted as consumptive. In cases where the evapotranspiration from the land use that preceded the reservoir is lower than estimated evaporation from the reservoir, consumption is counted as zero and no credit for water savings is allocated to hydropower, with the goal of creating a conservative estimate.

Work based on Penman-Monteith modeling of hydropower impoundments in the United States that uses k-means clustering to aggregate impoundments by region estimates that US hydropower systems consumed a net average of 1.8 m^3/delivered GJ and a total of 1.6 billion m^3 of freshwater in 2014 due to evaporation losses (Grubert 2016)[211]. These estimates are significantly lower than commonly-cited literature estimates of 4.7 m^3 (Gleick 1994)[3] and 17 m^3 (Torcellini et al. 2003)[212] in part because of the correction to net evaporation, which reflects the evapotranspiration that would have occurred absent the reservoir due to prior land cover. Gross consumption is estimated at 11 m^3/delivered GJ, which falls between prior estimates of gross evaporation.

Cluster analysis dividing the United States into 20 regions reduces data gathering needs substantially, enabling incorporation of all roughly 1,600 impoundments whose primary use is hydroelectricity. The Penman-Monteith model used in this work includes 12 external variable categories per analyte (including six with monthly resolution) that are converted to hundreds of variables within the model. An in-depth discussion, including sensitivity analyses and higher regional resolution, can be found in Grubert (2016)[211].

Seepage

Water impoundments for hydroelectricity generation seep, or lose water into surrounding rock. An unpublished 1978 estimate by Ingersoll that has been cited widely in works including Gleick (1994)[3] estimates that reservoirs might lose 5% of their volumes to seepage – compared with about 2.6% for net evaporation losses (5.1% for gross) estimated in Grubert (2016)[211].

Recent work at Lake Powell, a reservoir in an arid area with highly porous, heavily fractured rock and limited groundwater—and one that would be expected to lose much more than average water to seepage—suggests seepage loss is about 1.3% of reservoir capacity (Myers 2013)[213], or half of estimated gross evaporation loss for the Arizona / Utah region (Grubert 2016)[211]. Further, this loss number appears to be very high: a water management proposal for the Colorado River system suggests that losses could be cut by 80% if water were stored in nearby Lake Mead (with similar conditions, but less fractured rock) (Wedig 2013)[214]. At Lake Powell, seepage losses are clearly relevant to the water management system and might even exceed evaporation losses: however, Lake Powell appears to be an extreme example, even for dry-area reservoirs. Even at Lake Powell, there is an expectation that some seepage loss is likely stored water that would return to the system under some set of conditions: it is unclear in many cases whether water is truly lost to seepage or stored. Further, particularly in wetter areas that support crops and native vegetation along riverbanks and reservoir banks, seepage water contributes to local groundwater levels and can represent beneficial use within the same catchment. This analysis thus concludes that overall, seepage losses are likely locally significant in some locations but that very high (e.g., 5%) seepage loss is probably not observed nationally.

For the purpose of estimation, this analysis assumes that seepage losses of about half of gross evaporative losses are a high estimate for hydropower reservoirs based on the Lake Powell analysis and engineering rules-of-thumb for irrigation ponds that are not designed for long term storage; that no seepage loss (due to e.g., saturated banks) is a low estimate; and that losses of about 7.5% of gross evaporative losses are a best-guess estimate. Analyses of Lake Mead relative to Lake Powell and of desert-based reservoirs in western India suggest that seepage losses of 15% of evaporative losses are typical under those conditions (Grubert 2016, Khan and Bohra

1990, Wedig 2013)[211,214,215]. About 50% of hydropower-purposed impoundment volume (40% of area) is in regions where the surrounding vegetation is approximated as scrubland or pasture, indicative of less saturated reservoir banks and bottoms; the remainder are surrounded by crops, forests, or wetland (Grubert 2016)[211], suggesting that seepage losses are more limited given higher groundwater availability or beneficial use opportunity. Assuming 50% of reservoir volume experiences seepage loss equal to 15% of gross evaporation loss suggests a best-guess estimate of national seepage losses equal to 7.5% of gross evaporation loss, or 0.8 m^3/delivered GJ. This value is about 60% of the estimated average net evaporation loss for US reservoirs.

Withdrawal

Water withdrawal for hydropower conversion, in the form of water flow through penstocks and other unnatural channels for flow through turbines, is usually not estimated in the literature. This work argues that withdrawals for hydropower do represent disturbances to the aquatic system, even though concerns about thermal pollution, a common concern associated with water withdrawal for power production, are somewhat different. All water that is withdrawn to pass through turbines poses risks to aquatic life, though such impingement and entrainment risks are mitigated by protective infrastructure. (The overall effects of dams on aquatic ecosystems are orthogonal to questions about water withdrawal for hydropower but are nonetheless important.) Further, for impounded systems, impoundment represents a temporal delay in water's participation in its catchment, something that also changes the character of the water. Depth, chemical, and thermal changes associated with impoundment can have large and unmitigated effects on local aquatic ecosystems. Thus, this effort finds it appropriate to estimate water withdrawal for hydropower.

Based on assignation of water withdrawal at hydroelectric facilities fully to hydroelectricity at those facilities whose primary purpose is hydroelectricity and not at all to hydroelectricity at other facilities, as with the consumption calculations detailed above, this work makes an estimate of total water withdrawals for hydroelectricity of 2×10^{13} m^3, which is about 100 times the total estimated water withdrawal for the entire non-hydroelectric US energy system. To understand how this estimate can be so large, recall that many rivers are dammed multiple times for hydropower: the Columbia River, for example, has 11 dams on its mainstem. Thus, hydropower withdrawals can be many times the total volume of water flowing through a river, and most (if not all) of the US' major rivers are used for hydroelectricity. This outcome is consistent with the way withdrawals are measured for other electricity generation systems and with the spirit of the term withdrawal, which measures how much water is removed and returned to a water source.

The estimate made here of 2×10^{13} m^3 of water withdrawals for hydropower is based on a set of simple assumptions about discharge volumes at hydroelectric facilities. First, that maximum discharge through the turbines at hydroelectricity facilities is about half of the maximum discharge reported by the NID (USACE 2015)[216], which includes spillways that bypass the turbines; and second, that withdrawals for hydroelectricity are related linearly to the capacity factor of the facilities as reported by the EIA (2016)[217]. A withdrawal estimate is made as follows, where *i* denotes hydroelectric facilities whose primary purpose is defined in the NID as hydroelectricity:

$$Q_{\text{withdrawal}} \approx 0.5 \times \sum_i Q_{i,\text{max discharge}} \times \text{capacity factor}_{\text{US hydropower}}.$$

Note that this estimate is expected to be roughly accurate for the full hydroelectric system but not necessarily for individual dams due to its reliance on system-level allocation.

To check for reasonableness, the amount of power that this volume of water is expected to produce is also calculated. Based on the equation

$$P = \eta Q \rho g h,$$

where P is power, η is efficiency (estimated at 0.9 for hydroelectric turbines), Q is flow rate in m^3/s, ρ is the density of water (~1,000 kg/m^3), g is the gravitational constant (9.8 m/s^2), and h is head, this estimate of water withdrawal for hydropower implies an effective constant capacity of 31 GW given a discharge-weighted normal depth (including dead storage) of 8.0 m (USACE 2015)[216] and an assumption that on average, about two thirds of the discharge-weighted normal depth is available as head, or 5.3 m. This 31 GW estimate compares favorably to the 2014 effective constant capacity of about 30 GW, based on 2014 total generation and installed capacity of 79 GW with a 37% capacity factor (EIA 2016)[217,218]. While this withdrawal estimate is highly uncertain, it appears to be reasonable as a first approximation. For example, the average estimated head available from the 597 potential hydropower projects over 1 MW at non-powered dams in Oak Ridge National Laboratory's study (Hadjerioua et al. 2012)[219] is 5.3 meters. However, the withdrawal estimate is sensitive to assumptions about systemwide flow-weighted average head, as summarized in Table S10.

Table S10. Estimated 2014 flow through the US hydropower system as a function of average head, assuming purpose based allocation

systemwide flow-weighted average head (m)	withdrawals (m^3) for 2014 output
1	1.1E+14
2	5.5E+13
3	3.6E+13
4	2.7E+13
5	2.2E+13
6	1.8E+13
7	1.6E+13
8	1.4E+13
9	1.2E+13
10	1.1E+13
11	9.9E+12
12	9.1E+12
13	8.4E+12
14	7.8E+12
15	7.3E+12

Wind

The wind fuel cycle withdraws and consumes very small quantities of freshwater for cleaning once the turbines and other infrastructure are installed. In keeping with the scope of this analysis, water uses for e.g., concrete mixing and turbine manufacture are not assessed, though construction and decommissioning water use comprises the bulk of the life cycle water consumption and withdrawal for wind turbines (Meldrum et al. 2013)[6]. The wind fuel cycle consumes an estimated 3.2×10^{-3} m^3/delivered GJ and withdraws an estimated 3.2×10^{-2} m^3/delivered GJ of water during operations (Yang and Chen 2016)[220]. Operational water use is assumed to be (and require) fresh water given the goal of cleaning. Source water is assumed to track agricultural and public supply withdrawals, at about 60% surface water and 40% groundwater (Maupin et al. 2014)[9].

<u>Blade washing</u>

Wind farms are sometimes assumed to have effectively no operational water needs beyond possible central office hoteling. While the need is very small relative to needs for other forms of electricity, recent work has measured operational water use for wind turbine blade washing. Yang and Chen find that for a modern wind farm in Inner Mongolia, operational water consumption is about 3.2×10^{-3} m^3/delivered GJ, about 10% of the withdrawals of 3.2×10^{-2} m^3/delivered GJ (Yang and Chen 2016)[220]. This estimate is based on empirical measurement at the wind farm and is believed to be generalizable to other modern wind farms (Chen, pers. comm., 2016). This estimate is taken as the best guess for this research, as it represents measured data. The values are about three times estimates cited by Meldrum et al. of about 1×10^{-3} m^3/GJ consumption and about 1×10^{-3} m^3/GJ of withdrawal, based on engineering and industry association estimates from the mid 1990s and early 2000s (Table A-32, 2013)[6]. (Note that the median estimate presented in the main paper suggests consumption of between 1 and 5×10^{-4} m^3/GJ, likely due to the inclusion of a 2003 estimate two orders of magnitude smaller than the other two, presented in the SI: a copy of the original reference could not be located, so this work notes it as a referenced outlier and defers to the most empirical estimate.)

The Yang and Chen[220] estimate adopted here implies that wind power uses about half as much water as solar photovoltaic power for washing (see below; based on Macknick et al. 2012)[221]. However, as described in more detail in the solar section, wash water use is likely declining over time for solar.

Other water uses in the wind fuel cycle

While this research focuses on operational water use, we note that upstream and downstream water use is more significant to the overall fuel cycle for wind than it is for most thermal fuel cycles. Meldrum et al. present a harmonized estimate for life cycle water use, estimating consumption of about 1×10^{-3} m^3/GJ and withdrawal of about 3×10^{-2} m^3/GJ for the entire onshore wind fuel cycle (2013)[6]. Yang and Chen come to a similar conclusion, but with higher estimates for consumption as a portion of withdrawals, estimating that the overall wind fuel cycle consumes about 1×10^{-2} m^3/GJ and withdraws about 3.5×10^{-2} m^3/GJ (2016)[220]. The dominant contributor to both withdrawal and consumption in this estimate is the embodied water in steel (Yang and Chen 2016)[220].

Solid Biomass and Refuse-Derived Fuels

Water use for the solid biomass and refuse-derived fuel (RDF) fuel cycle is dominated by cooling at power plants, with additional water required for some types of fuel processing and waste handling. This work includes wood (including both solid and liquid byproducts, most notably black liquor), MSW, agricultural byproducts, and tire-derived fuels in this solid biomass and refuse-derived fuel category (Table S11). As carbon-based fuels, solid biomass and refuse-derived fuels also produce minor amounts of water during combustion. Overall, this work estimates that US solid biomass and RDF consumes 0.14 m^3/GJ delivered energy of freshwater and withdraws 3.3 m^3/GJ delivered energy through these mechanisms based on a 2017 analysis.

Table S11. Solid biomass and refuse-derived fuels by contribution to the total 2014 electricity generation by the whole category

Fuel type	Percent of solid biomass and refuse-derived fuel
wood	79.7%
MSW	16.8%
sugarcane bagasse	1.7%
tires	1.3%
other agricultural byproducts	0.6%

Source: EIA 923 for 2014, manual plant-by-plant web searches for plants classified as AB, OBL, and OBS.

Note: Values might not add to 100% given rounding.

As with other resources, this research investigates only water withdrawals and consumption applied by humans, which excludes the direct water input from precipitation that supplies essentially all of the water needed to grow woody biomass. That is, reported values are the "blue water footprint" (Hoekstra et al. 2011)[222]. This decision is more relevant for fuels like solid biomass where green water footprints can be significant (see e.g., Mekonnen and Hoekstra 2011, Gerbens-Leenes et al. 2009)[63,223] than it is for fossil fuels and others that do not rely directly on crop growth (though see D'Odorico et al. 2017 on the ancient water embedded in fossil energy)[224]. In practice, the US used very little solid biomass from non-wood crops in 2014, at about 40 million GJ of fuel consumed (2% of US solid biomass fuel and 0.04% of US energy consumption, EIA 2017 Table 1.1)[225]. Of this, about 75% was sugarcane bagasse burned at five facilities (EIA 923, 2014)[1], one of which has since closed (Imada 2016)[226]. If use shifts toward irrigated biomass, the water intensity of solid biomass fuels could change substantially.

<u>Extraction and Fuel Capture</u>

Irrigation is the primary mechanism through which solid biomass and refuse-derived fuels withdraw and consume water at the extraction and fuel capture stage of their life cycle, though the solid biomass and RDF fuel mix in the US in 2014 included almost no irrigation burden. This work assumes that non-forest purpose-grown crops and crop residues require irrigation water, while wood biomass and RDF do not. Further, this work assumes that withdrawals and consumption are equal for irrigation. Note again that this discussion excludes green water footprints, or the portion of water directly derived from precipitation. See e.g., Mathioudakis et al. (2017)[75] for more detailed investigations including green water, including for trees.

Non-forest purpose-grown crops

Data from EIA Form 923 do not suggest that any non-forest purpose-grown crops were used for energy in 2014 in the US. While there might be localized exceptions, particularly for boilers that fall below the 923 reporting threshold, they are not addressed here. See e.g., Mathioudakis et al. (2017)[75] and Mekonnen and Hoekstra (2011)[223] for more on the water intensity of prospective purpose-grown crops for use as solid biomass resources.

Crop residues

Crop residues burned as energy resources have value that is sometimes relevant to a crop's being economic (HC&S 2017, ADM 2009)[227,228]. Thus, irrigation water is allocated to these byproducts. In the US in 2014, based on EIA 923 data, the vast majority of crop residues recorded for use as energy resources were sugarcane bagasse, at about 30 million GJ burned in Florida, Hawaii, Louisiana, and Texas. Other crop residues burned as energy resources include residues from rice (6 million GJ), corn (2 million GJ), sunflowers (2 million GJ), and cotton (0.2 million GJ). Given the small overall contribution to the system, this work does not attempt to derive more specific values for the water intensity of bagasse, taking values instead from Mathioudakis et al. (2017)[75]. Note that these values are not US specific and might refer to slightly different crop residues than are being used, like corn stover versus waste seed corn.

Table S12. Crop residue 2014 energy consumption and water intensities

Fuel	Fuel consumption for heat, GJ	Fuel consumption for electricity, GJ	Blue water intensity m^3/GJ combusted
bagasse	26.5	4.2	1.8
rice	1.7	4.1	2.1
corn	1.1	0.8	1.3
sunflowers	1.3	0.6	1.6
cotton	0.2	0	3.2

Sources: Mathioudakis et al. 2017, Table H.9; EIA 923 for 2014

Note also that an estimated 0.1 million GJ of fish processing waste and 0.6 million GJ of biodiesel derived from waste fats and oils are burned for energy (EIA 923, 2014)[1]. These resources are assumed to have no extraction or capture-related water use.

Wood biomass

For the purposes of this analysis, wood biomass includes forestry products, urban and forest woody residues, wood processing residues like black liquor and sawdust, and other woody byproducts, including wood-based poultry litter. This work assumes wood is nonirrigated, based on e.g., Wu et al. (2014, Fig. 1)[65] and Mathioudakis et al. (2017, Fig. 4)[75].

Though wood biomass—even purpose-grown wood for energy—is assumed to be nonirrigated in the US, note that the US is an exporter of wood pellets for use as biomass energy abroad. Though this survey did not exist for the analytical year of 2014, EIA reports that US-produced densified biomass fuel (wood pellets) is primarily (>80%) burned abroad (EIA 2017, Monthly Densified Biomass Fuel Report)[229]. Water used outside the US for e.g., cooling and waste disposal is not included in this analysis.

Municipal Solid Waste and Tire-Derived Fuels

Combustion is a disposal process for Municipal Solid Waste (MSW) and tires as tire-derived fuels (TDF), so any water embodied in these waste products is not attributed to the creation of fuel. Note that this decision is not inconsistent with the choice to attribute some water to crop residues burned as fuel because the decision to generate MSW (trash) or to discard tires is not economically motivated by the potential for energy generation.

Transportation

Transporting solid biomass and refuse-derived fuels is assumed to require no direct water withdrawal and consumption. In practice, some water is likely used for dust control and vehicle or conveyor washing.

Processing

The primary processing steps associated with preparing solid biomass and refuse-derived fuels for combustion are sorting, dehydrating, and sizing (often, shredding or chipping). The ultimate goal is to produce a low-ash, low-moisture product (see e.g., Van Loo and Koppejan 2008)[230]. This processing is not considered to consume or withdraw any water, though in practice some water is likely used for dust control, hoteling, etc. at most facilities. While some water is released during dehydration, that embodied water is either "green water" from precipitation (and thus exists in a definitional gray area with respect to withdrawal and consumption in later life cycle stages) or has already been accounted for as an extraction use.

Power generation

Power plant cooling

Please see the section on Thermoelectric Power Generation for details on the calculation of water use for cooling at solid biomass and RDF-fired power plants.

Flue Gas Desulfurization

As for coal-fired power plants, water use for flue gas desulfurization is included in power plant water withdrawals and consumption and is thus formally accounted for as electricity generation water use. However, given the heterogeneity of the solid biomass and refuse-derived fuel cycles, it is relevant to note that some fuels need more waste management interventions than others. In particular, MSW and TDF have relatively high sulfur content, while wood and agricultural wastes generally do not. The major exception is black liquor, the pulp and paper manufacturing byproduct. However, sulfur from black liquor is generally either recovered by means other than flue gas desulfurizers (in part because Na_2S is a pulping chemical that can be recovered, Van Heiningen 2006)[231] or does not trigger a need for FGD, perhaps because the black liquor is not the only fuel used at a plant (e.g., Naqvi et al. 2012)[232]. No attempt is made to characterize FGD water use separately for biomass, as EIA 923 data suggest that only three plants burning solid biomass or RDF produced FGD products in 2014. In all cases, these plants are primarily coal plants, with biomass accounting for about 1% or less of the total output according to EIA 923 data for 2014. Thus, this work simply notes that MSW and TDF use can require sulfur scrubbing, and black liquor use requires sulfur management of some kind, while most other forms of biomass do not.

Combustion

Biomass releases water alongside CO_2 when it is combusted. This water is an addition to the active hydrologic cycle, as combustion occurs within the boundaries of the active hydrologic cycle. On average, combusting solid biomass produces about 0.04 m^3 of fresh water vapor/delivered GJ, assuming an average H/C ratio of 1.6 and about 56% total mass as carbon and hydrogen. This can be considered production of surface water, which may fall as rain and either remain fresh or become part of the ocean.

MSW releases water alongside CO_2 when it is combusted. This water is an addition to the active hydrologic cycle, as combustion occurs within the boundaries of the active hydrologic cycle. On average, combusting MSW produces about 0.01 m^3 of fresh water vapor/delivered GJ, assuming an average H/C ratio of 1.8 and about 50% total mass as carbon and hydrogen. This can be considered production of surface water, which may fall as rain and either remain fresh or become part of the ocean.

Ash handling

Solid biomass and RDF produce ash upon combustion, much like coal. According to EIA 923 8A, no non-coal plants (where a coal plant is defined as a plant burning more than 95% coal on an energy basis) produced solid byproducts that were ponded. Investigation of biomass burning plants and ash production suggests EIA 923 8A data are too coarse to generate a good estimate for water use for ash handling associated with biomass burning. Plants that produced solid wastes reported on EIA 923 8A that also burned at least 50% biomass on an energy basis accounted for only about 6% of biomass energy, and some of the solid waste at those plants is likely attributable to the coal and petroleum coke burned at the same plants. Instead, this work uses an estimate for ash generation from solid biomass and RDF based on ash content and total solid biomass and RDF energy. Solid wood ash content is estimated at 2% for this work, noting that barkless wood has considerably lower ash content (Fantozzi and Buratti 2010, Krajnc 2015)[233,234]. Reports of ash content for wood-based black liquor vary, from about 10% to about 35% of undried weight (Carlsson et al. 2010, Demirbaş 2002, Zhou et al. 2010)[235–237]. This work assumes ash content of about 25% of undried weight, similar to that reported in Demirbaş (2002). MSW is usually 15-25% ash by weight (EPA 2017)[238], so this work arbitrarily chooses the midpoint (20%) to estimate ash generation from MSW combustion. Ash content for tire-derived fuels is estimated at about 5% by weight (Gray 2004)[239]. Ash content for rice and sugar residues are estimated at 15% and 1.5%, respectively, based on recent studies (El-Mekkawi et al. 2011, Minu et al. 2012, Hamlin 1993)[240–242]. Other small biomass energy resources (primarily sunflower hulls and waste seed corn) are arbitrarily assigned about 2% ash content due to similarity to wood and sugar. Based on these assumptions, and assuming that moistened ash is 10% water and 90% ash by weight, total water used for solid biomass and RDF ash handling is estimated at 2.4 million m^3 for 2014, or 3.2×10^{-3} m^3/GJ combusted. As with coal, this water is assumed to be fresh with water use accounted in EIA 923. Here, it is subtracted from overall power plant water use and reported separately.

Biogas

The biogas fuel cycle withdraws and consumes water for cooling at a minority of the power plants where it is burned (as much biogas combustion takes place at air-cooled facilities), estimated at 4.6×10^{-2} m^3/ delivered GJ of freshwater. As of 2014 in the US, no other dedicated water is assumed to be used for the biogas fuel cycle. As a carbon-based fuel, biogas also produces water through combustion.

Extraction and Fuel Capture

Based on data from EIA form 923 (EIA 2015)[1], most biogas used for energy in the US in 2014 was associated with landfills (~78% of biogas). The remainder is almost entirely from municipal or industrial wastewater or animal manure digesters. While some individual industrial and agricultural operations might be viable because of biogas, which would suggest that some water used for the main product should be allocated to the biogas coproduct, most biogas is a nondiscretionary byproduct of wastes and does not alter decisions about the processes used to create the waste. Thus, no water is assumed to be dedicated to creating biogas.

Processing

The main processing requirement for biogas is for scrubbing to remove water, which is similar to the dehydration step in natural gas processing. Since this water is part of the waste, it is not considered a withdrawal or consumption of water.

In addition to water, biogas contains acid gas contaminants. Biogas usually contains only trace amounts of H_2S but typically has much higher CO_2 content than does fossil natural gas, at 35-50% (Nock et al. 2014, EPA 2017)[243,244]. While these acid gases could be removed, in practice, they rarely are. CO_2 need not be removed if the biogas is used onsite and is therefore not subject to pipeline quality requirements (CEC 2017)[245]. Few projects (~50 of 850 active landfill gas projects as of 2014) upgrade biogas by removing CO_2, but those that do account for about 18% of landfill gas volumes as of 2014 (EPA 2017)[246]. However, none of those projects appear to use water-intensive amine scrubbing, instead using membranes and physical solvents (EPA 2017)[246]. Data are less available for non-landfill biogas, but similar assumptions are made. Thus, this work assumes negligible water is expended to strip CO_2 or H_2S from biogas in the US. Nock et al. (2014)[243] provide more detail on the upgrading process for interested readers.

Note that if biogas facilities do use water for processing, much of the water is likely to be reclaimed (see e.g., page 15, Robillard 2014)[247]. Most non-landfill biogas (~80%, EIA 923) is generated at municipal and industrial (e.g., brewery) wastewater treatment facilities that have easy access to reclaimed water. The remainder is generally associated with animal manure lagoons.

Transportation

Biogas is often used onsite. Since pipeline quality biogas is rare (EPA 2017)[246], this work assumes no additional water allocated for biogas transportation. In practice, some water is likely used for hydrostatic testing of tanks and on-site piping.

Power generation

Power plant cooling

EIA data suggest that most biogas-burning facilities do not require water cooling, as they use gas turbines or internal combustion engines. Please see the section on Thermoelectric Power

Generation for details on the calculation of water use at biogas-fired power plants using steam turbines (including the steam portion of combined cycle plants), which account for about 17% of biogas use.

Combustion

Biogas releases water alongside CO_2 when it is combusted. This water is an addition to the active hydrologic cycle, as combustion occurs within the boundaries of the active hydrologic cycle. On average, combusting biogas produces about 0.04 m^3 of fresh water vapor/delivered GJ, assuming an average H/C ratio of four given that the energy-bearing component of biogas is methane. This can be considered production of surface water, which may fall as rain and either remain fresh or become part of the ocean.

Geothermal

The geothermal electricity fuel cycle consumes freshwater for drilling, reservoir augmentation, and power plant cooling. Like oil and natural gas cycles, geothermal cycles can also produce formation water that would not otherwise have been part of the active hydrologic cycle, usually by use of geofluids for evaporative cooling. This work relies primarily on Energy Information Administration data and intensity factors from a 2013 life cycle water analysis by Argonne National Laboratory to estimate total 2014 water use associated with US geothermal electricity systems (Clark et al. 2013, EIA 2015 860 and 923 files)[1,248,249]. Argonne's analysis is based on a GeoRef literature review from 1990 to 2013 and a review of NEPA documents for 38 geothermal projects (Clark et al. 2013)[249]. Based on Argonne water intensity estimates and 2014 production data, US geothermal electricity consumes an estimated 3.1 m^3/delivered GJ of freshwater (100% of withdrawals), through these three mechanisms. Geothermal electricity uses mostly fresh water, which is appropriate for closed-loop wet cooling. Lower quality waters that are chemically compatible with reservoir fluids could be deployed for aquifer augmentation: reclaimed water is already used at The Geysers, and the salinity of many geofluids suggests that where available and cost effective, more brackish water could be used.

Geothermal for direct heat withdraws an estimated average 2.7 m^3/process-GJ of fresh groundwater (27 m^3/process-GJ for open loop systems and 0 for closed loop systems). Consumption is estimated at zero, though this is likely an underestimate for reasons detailed below.

Well development

Geothermal plant systems rely on wells to pump and inject fluids. Well development uses water primarily for drilling, though future plants could use more water for well stimulation and flow testing. Such water is assumed to be freshwater that is already an active part of the hydrologic system. Clark et al. estimate water consumption of 1860 m^3/km drilled for exploration wells and 2200 m^3/km for production and injection wells (2013)[249]. Using the 2015 US Country Update (Boyd et al. 2015)[250] to determine total drilled depths in 2014, 2014 water consumption for geothermal power well drilling is estimated at 5.4×10^5 m^3. Clark et al. note that of 24 drilling project data points they considered, 20 used groundwater, two used surface water, and two used condensate or reclaimed water (2013)[249]. Though number of projects is not a perfect proxy for amount of water in each category, these ratios are used to estimate volumes of water used by source. This work assumes that drilling water is 100% consumed, so withdrawals are the same.

Conversion

Power plant cooling

Geothermal systems in the United States take one of essentially three forms: dry steam plants, flash steam plants, and binary plants. Dry steam plants are globally very rare, with long-term installations at The Geysers in California and Lardarello in Italy. While The Geysers are important for characterizing US geothermal due to the high net installed 2014 capacity of about 1,400 MW (CEC 2016)[251] out of a US 2014 total of about 3,500 MW (Matek 2015)[252], data from dry steam plants is not representative of future development in the US or elsewhere. Newer plants are and will be one of three basic types: flash steam, where water exists in liquid phase underground but is sufficiently pressured and heated to flash to steam upon ascent to the surface and exposure to atmospheric pressure; binary plants, where formation water is not hot enough to flash to steam on its own but can be used to transfer heat to a fluid with a lower boiling point that is used as the plant working fluid; or enhanced geothermal systems (EGS), also known as "hot dry rock," where wells are drilled into areas with high underground temperatures and water is circulated to pick up the heat, then used in a flash or binary cycle at the surface, depending on temperature.

Like other steam-based power plants, geothermal plants can be wet cooled, hybrid cooled, or dry cooled. A major difference in cooling practice, however, is that wet-cooled dry and flash steam plants are often evaporatively cooled using their own formation water, called geofluid. Geofluid is often highly mineralized and, coming from depths of 1-6 km (Clark et al. 2013)[249], is often isolated from the active hydrologic cycle. Thus, evaporation of geofluid more accurately represents production of freshwater (in that previously isolated water is being liberated into the atmosphere, and evaporation purifies the mineralized geofluid) than consumption. However, when plants inject water as makeup to maintain reservoir pressure, previously active freshwater is sequestered in the geothermal reservoir either permanently or until it is liberated by the geothermal plant again (discussed below under "field makeup water"). Given the dynamic of injection balanced by release of water as vapor (and thus not a direct return to the original source), injected volumes are assumed to represent both withdrawal and consumption of water associated with plant operations.

Conventions differ on how to account for evaporative consumption of geofluid, the hot water or water vapor in the geothermal reservoir that is liberated as fresh water through evaporative cooling systems at steam plants. The geothermal literature often does not classify such water as consumed (Harto et al. 2013)[253]. In keeping with the conventions adopted by this work, however, evaporation of geofluid is counted here as a production-phase consumptive withdrawal of groundwater that is liberated through evaporation to the atmosphere. The water is classified as fresh groundwater, as it is liberated as freshwater.

The EIA does not track water use for any geothermal plants in its forms 860 and 923, though it does include information on water source. Thus, estimation was performed in three steps. First, basic EIA data about 2014 geothermal electricity water source, prime mover, capacity, and production was gathered from forms 860 and 923 and compared with industry estimates and peer-reviewed literature to confirm that basic capacity numbers are consistent across sources. Next, these data were combined with plant-specific documents for each of about 50 geothermal complexes (194 generators) to classify water source, water quality, cooling system type, and plant type. All plants at The Geysers were assumed to be dry steam; all other plants with prime mover = steam turbine were assumed to be flash steam; and all plants with prime mover = binary turbine were assumed to be binary cycle plants. These assumptions held up well with more specific documentation.

Plants with water sources listed as wells or geofluid were classified as groundwater users, and geofluid was classified as brackish. All other water was classified as fresh, absent clear notes to the contrary. Cooling type was confirmed directly from press releases, environmental assessments and impact reports, and other sources. Plants listed as using both air and wet cooling were classified with newer units using air cooling and older units using wet cooling, when a large gap between builds and a technology change for the newer plants was inferred, or as using a hybrid system in other cases. Finally, Argonne life cycle factors were applied on a per-production basis (Table S13), and water withdrawal and consumption were aggregated by source and quality.

Table S13. Withdrawal and consumption factors for geothermal power plant cooling systems, m^3/process GJ

Geothermal System	Water Consumption, m^3/GJ	Water Withdrawal, m^3/GJ
steam, wet cooled	0.05	0.05
steam, hybrid cooled	0.04	0.04
binary, wet cooled	2.8	2.8
binary, hybrid cooled	1.1	1.1
all, air cooled	0.04	0.04

Source: analysis based on Clark et al. 2013

Notes: geofluid production not used for cooling and reservoir augmentation water are accounted for in other processes

Where individual units have different cooling profiles, as when one generator is air cooled and another is wet cooled, water consumption and withdrawal rates are taken as the installed capacity-weighted average since unit-level production is not available. Multiple cooling types are present for only 3% of capacity, so the impact of this simplification is small. Overall, binary capacity is much more likely to be air cooled than steam capacity. About 50% of binary capacity is air cooled, while only about 1% of steam-based geothermal capacity is air cooled.

Field make-up water

Only three geothermal power complexes out of the roughly 50 operating in the United States as of 2014 seem to be practicing reservoir augmentation, where external water is pumped underground to maintain pressure in the reservoir (Harto et al. 2013)[253]. These three systems represent about 54% of US geothermal production in 2014, however, largely due to repressurization activities at The Geysers (accounting for 40% of 2014 production) (EIA 923)[1]. This repressurization is meant to replace the geofluid from a dry or flash steam field that is evaporated and thus not returned to the reservoir. Such water is classified here as production-related use, in keeping with a similar classification for enhanced oil recovery water. The decision to augment is usually contingent on the continued value of the heat resource, the availability of water, and the ability of the heat resource to resist major degradation from contact with cool water. Extreme caution is recommended for any attempts to use data from existing augmentation programs to estimate a rate of water consumption per unit of energy produced: augmentation water leads to additional production capacity, but the amount of capacity made possible by augmentation is highly dependent on factors like heat, porosity, and economics, so intensity factors incorporating augmentation water should be considered descriptive rather than predictive.

Whether field make-up water demands grow in the future is technologically dependent, since a category of plant known as Enhanced Geothermal Systems (EGS), also called “hot dry rock” plants, could potentially require large volumes of water. Enhanced Geothermal Systems (EGS) do not yet exist at utility scale in the US, though work has begun on EGS components at several US geothermal complexes (Clark et al. 2013)[249]. EGS are interesting from a water perspective because they use artificial hot water systems, which means they rely on externally supplied formation water. This water can be lost to reservoir fractures and other means, representing effectively permanent sequestration of water that was previously active in the hydrologic cycle. Such belowground losses are estimated to be about 5% of total injected volumes, or 0.9 m^3/GJ, with fairly high uncertainty (Clark et al. 2013)[249]. Nonviable projects can see much higher loss rates—up to 75%—during testing (Clark et al. 2013)[249]. Injected water need not be fresh, but it does require chemical compatibility with the formation (Clark et al. 2013)[249]. If EGS are not developed, make-up water demands could grow as steam plants get older. Steam plants tend to consider augmentation as resource exploitation causes reservoir pressure to drop, but only in liquid-limited rather than heat-limited systems (otherwise, the heat resource is insufficient to benefit from augmentation). Binary plants, which are growing more common, do not need repressurization because of the closed loops involved.

This work did not find evidence of augmentation programs other than the three reported by Harto et al. and thus characterizes these three as of 2014: The Geysers complex, the Coso complex, and Dixie Valley (2013). The Geysers is both the biggest complex in the US and operates the biggest augmentation program to maintain its extraordinarily high quality steam resource. In 2014, The Geysers consumed about 1.7×10^7 m^3 of fresh reclaimed wastewater from two sources: 1.5×10^7 m^3 from the Santa Rosa Geysers Recharge Project and 2.1×10^6 m^3 from the Calpine Southeast Geysers Effluent Pipeline (Calpine 2016)[254]. Both of these water sources are reclaimed post-treatment wastewater from neighboring communities; while fresh, the water was considered a contaminant to previous receiving waters due to high nutrient loads.

The Coso complex, located on military property on the Naval Air Weapons Station at China Lake, is a liquid-limited system that uses fresh groundwater from the Hay Ranch Project to boost field pressure (MHA 2008)[255]. In 2014, the project withdrew and consumed 2.0×10^6 m^3 of groundwater (Inyo County 2015)[256]. The smallest augmentation program, at Dixie Valley, injects an average of 0.03 m^3/sec to its reservoir (Benoit et al. 2000)[257]. This translates to an estimated 9.5×10^5 m^3 per year.

Direct heating

The United States has an estimated 17 MW_{th} of geothermal direct heating systems installed, operating at about 13% capacity as of 2014 (Boyd et al. 2015)[250]. Electric power generation systems account for 2,500 net MW_e operating at about 75% capacity factor, by contrast (Boyd et al. 2015)[250]. While direct heating applications thus account for most individual geothermal installations, they use water very differently. Water consumption associated with direct heating geothermal applications in the United States is estimated to be very low, as about 90% of installed capacity (based on Boyd et al.'s use of 12 kW-equivalent units to describe installations) is closed loop, refrigerant-based systems (2015)[250]. The remaining roughly 10% of systems are water-based open loop systems that withdraw fresh surface or groundwater as a working fluid (Boyd et al. 2015)[250]. Older "pump and dump" systems might not return the water (thus consuming it), but newer systems are more likely to reinject the water to the aquifer given environmental concerns. It is not clear how many of each system exists, though EPA documents from 1997 caution that surface disposal is disallowed in many situations (EPA 1997)[258]. Wells are sufficiently shallow, about 75 meters on average (Boyd et al. 2015)[250], that water use for drilling is ignored for this analysis.

For simplicity, this work assumes that all open loop systems return the water to the same aquifer from which it was withdrawn and that all open loop systems operate using fresh groundwater. These assumptions are unlikely to be fully accurate. Further, this work assumes that open and closed loop systems have identical system-wide capacity factors due to a lack of data indicating otherwise. Based on relative age, environmental concerns, cost (particularly as flow rates must be higher during colder periods to prevent freezing), and water chemistry issues, it seems more likely that open loop systems have lower capacity factors than closed loop systems, but this guess has not been externally verified. Comments on geothermal community sites (e.g., Geothermal Genius 2010)[259] suggest that closed loop systems are more reliable, also implying open loop systems might have lower capacity factors.

Given the caveats explained above, total water withdrawal for open loop direct heat geothermal applications is estimated at 27 m^3/process-GJ, for a total of about 200,000 m^3 of fresh groundwater withdrawals for direct heat applications in 2014. This water is categorized as a conversion-related withdrawal. This estimate is based on multiple installer and DIY site estimates that typical open loop systems require about 1.5 gpm of water flow per ton of capacity (GeoJerry 2014, WaterFurnace 2016)[260,261], where a ton is 288,000 btu over a 24-hour period. Consumptive use is estimated at 0. The withdrawal estimate is likely conservatively high, given that capacity factors for open loop systems are probably lower than for closed loop systems, and the consumption estimate is likely too low, given that some surface discharge of withdrawn groundwater occurs.

Solar Photovoltaic

The solar photovoltaic (PV) fuel cycle consumes freshwater for panel washing. This work adopts an estimate (likely to be conservatively high) that US solar PV withdraws and consumes 6×10^{-3} m^3/GJ electricity of freshwater for washing, based on a 2014 harmonization review by Macknick et al. (2014)[262]. However, trends appear to indicate that such use is likely to decline as the industry matures. Given the emphasis on washing delicate equipment, PV washing requires the fresh water that it uses. All washing water is assumed to be groundwater given the relatively dry areas typical of PV installations.

Washing

Evidence indicates that at both the utility and small (rooftop) scales, washing PV panels is unlikely to provide sufficient energy output increases to justify the expense of washing (Meldrum et al. 2013, Mejia and Kleissl 2013)[6,263]. A widely cited environmental impact statement for a large PV farm (Topaz Solar Farm in California) estimates no planned water consumption for panel washing (DOE 2011, p 2-45)[264]. A 2014 harmonization project based on analysis of nine data sources, considered a comprehensive review, estimates median operational water use of 6×10^{-3} m^3/delivered GJ (0.023 m^3/MWh), with low and high values of 1×10^{-3} and 3×10^{-2} m^3/delivered GJ (0.004 and 0.098 m^3/MWh) (Macknick et al. 2014)[262]. However, evidence suggests that few operators wash PV panels in practice (DOE 2012)[265], relying instead on rainfall and potentially moving toward water-free cleaning techniques (see e.g., Ecoppia 2015)[266], so this value is likely to decline as PV electricity becomes a more mature technology.

As Klise et al. note, PV system operational water consumption is a function of plant size rather than plant output (2013)[267]. However, given the tendency to site PV facilities in areas with similarly high insolation, this analysis assumes that output scales roughly proportionately with size and adopts Macknick et al.'s median value as a best-guess mean estimate (2014)[262].

Other water uses in the solar PV fuel cycle

As with wind, we note that upstream and downstream water use is more significant to the overall fuel cycle for solar PV than it is for most thermal fuel cycles. While water consumed during site preparation and construction is outside the scope of this work, PV plants often require reliable water access to support preoperational water needs (Brewer et al. 2015)[268]. Accordingly, water availability can be a constraint on construction. Macknick et al. provide a deeper discussion of solar PV manufacturing water use, estimating median water consumption and withdrawal of 0.03 and 0.1 m^3/delivered GJ for crystalline silicon PV and 0.01 and 0.2 m^3/delivered GJ for thin film PV (2014)[262]. These estimates suggest that water use in the solar PV fuel cycle remains dominated by manufacturing needs and that overall water requirements for PV are substantially lower than for other forms of electricity.

Solar Thermal

The solar thermal fuel cycle consumes freshwater for plant washing and cooling. This work estimates that US solar thermal electricity systems withdraw and consume 2×10^{-2} m^3/GJ for washing, about three times as much as PV systems. Solar thermal power plants withdraw and consume an estimated 1.6 and 0.9 m^3/delivered GJ for makeup water, power plant cooling, and power plant utilities as of 2014, with a likely downward trend associated with newer plants' use of hybrid and dry cooling systems. Over 95% of both withdrawal and consumption is fresh water. About 45% of withdrawal and 75% of consumption are groundwater, while 55% of withdrawal and 25% of consumption are surface water.

Solar thermal industrial steam generation, currently applied in oilfields, is accounted for in the oil resource section. Small heating applications like solar thermal hot water are excluded from this analysis due to their expected low water use.

Washing

Mirrors used to concentrate the sun's heat at concentrating solar facilities must be washed to maintain their reflectiveness. The Solar Energy Industry Association estimates freshwater consumption of 2×10^{-2} m^3/GJ for washing (SEIA 2016)[269]. As with PV, this wash water is assumed to be 100% consumed and 100% groundwater, so wash water withdrawals are also estimated at 2×10^{-2} m^3/GJ. Since solar thermal power plants depend on a highly intense beam of sunlight being focused precisely, clean mirrors are more important than clean panels at photovoltaic farms, so a similar trend toward no washing is not expected at solar thermal facilities. Freshwater is required due to the need to avoid scaling.

Conversion

Power plant cooling

Solar thermal plants have been criticized for their water intensity, particularly as good solar thermal sites tend to be in arid areas. Relative to conventional fossil fuel thermal power plants, wet-cooled solar thermal plants tend to require more water for two major reasons. First, due to lower temperatures, solar thermal plants are usually less thermally efficient than a coal- or natural gas-fired power plant, which means that more of the input energy is lost to a cooling system as heat. Second, solar thermal plants do not use combustion to produce heat, which means they do not lose any waste heat out of flue gas stacks and instead need to actively cool all their waste heat, unlike combustion plants (this condition also applies to nuclear plants).

Based in part on concerns from regulators and the public about water availability for desert solar thermal plants, as well as on the actual paucity of available water in favorable sites, the degree to which large scale solar thermal buildout will continue in the United States is uncertain. More clear is that newer plants, and plants yet to be built, are likely to have lower cooling water intensity on average than older plants (Bracken et al. 2015)[270].

Wet-cooled facilities like the Solar Electric Generating Systems (SEGS) dominate the water profile for solar thermal, with the SEGS consuming an estimated 0.8 m^3/delivered GJ and withdrawing an estimated 0.9 m^3/delivered GJ for cooling (NREL 2008, Cohen et al. 1999)[271,272]. Newer wet-cooled facilities are more water intensive, based on early production data and environmental assessment estimate. Nevada's 72 MW Solar One consumes and withdraws an estimated 1.2 m^3/GJ of potable water from Boulder City (originating in Lake Mead) (Bracken et al. 2015)[270], and Arizona's 250 MW Solana Generating Station consumes and withdraws an estimated 2.5 m^3/GJ of fresh groundwater, based on EIA 923 data from 2014. As of 2014, Solana was operating at about two-thirds of its intended output, which might be a contributing factor to its high water use. Its environmental assessment estimates suggest a planned rate of 1.7 m^3/GJ for both withdrawal and consumption (DOE 2010)[273].

EIA 923 does not include data for many of the operating solar thermal power plants as of 2014: only Solana has solar-specific withdrawal and consumption data. The Martin Next Generation Solar Energy Center is integrated to a larger natural gas and oil-fired power plant, and reports in POWER Magazine indicate that the addition of solar did not raise water use: thus, Martin's water withdrawal and consumption are assumed to be the same per GJ of output for the solar and natural gas portions of the plant (Neville 2011)[274]. Other plant water uses were estimated based on existing literature (SEGS) or environmental assessments or impact statements; only Solana and SEGS water use estimates are based on empirical measurements during operations. Water intensity, source, and quality are summarized in Table S14.

Table S14. Water use for conversion, US solar thermal electricity generation, 2014

Plant	Generation (MWh)	Withdrawal (m^3/GJ)	Consumption (m^3/GJ)	2014 withdrawal (m^3)	2014 consumption (m^3)	Water source*	Water quality*
Martin	124,476	12.1	0.2	5.4E+06	1.1E+05	surface water	fresh
SEGS I-IX	571,993	0.9	0.8	1.9E+06	1.7E+06	surface water	fresh
Nevada Solar One	116,227	1.2	1.2	5.0E+05	5.0E+05	surface water	potable
Solana Generating Station	603,567	2.5	2.5	5.5E+06	5.5E+06	groundwater	fresh
Ivanpah 1	151,966	0.0	0.0	5.9E+03	5.9E+03	groundwater	fresh
Ivanpah 2	129,263	0.0	0.0	5.0E+03	5.0E+03	groundwater	fresh
Ivanpah 3	137,856	0.0	0.0	5.3E+03	5.3E+03	groundwater	fresh
Genesis	576,113	0.1	0.1	2.1E+05	2.1E+05	groundwater	brackish
Total or Generation-weighted average	2,411,461	1.6	0.9	1.4E+07	8.1E+06		

Sources: CEC 2010a, CEC 2010b, Cohen et al. 1999, EIA 923 2014, Bracken et al. 2015, Neville 2011, USDOE 2011.

Notes: These values include water for boiler makeup, cooling, and hoteling. Water used for mirror washing has been subtracted and accounted for as a pre-conversion water requirement. All plants are assumed to use 0.02 m^3/delivered GJ of fresh water for mirror washing, which is relatively negligible for all plants other than Ivanpah.

The newest plants, and currently planned plants, reflect growing public and regulatory concern about water use by desert solar plants. While wet-cooled plants have continued to come online, as with the 250 MW parabolic trough projects at Solana (online 2013) and Mojave (online December 2014, not included in this analysis) (NREL 2016)[271], developers have had to address pressures about cooling systems more seriously as time has passed. For example, a Californian parabolic trough project known as Genesis (online as of 2014) was originally planned as a wet-cooled plant but was switched to a dry cooling system based on regulator concern (CEC 2010)[275]. Solar power tower projects Ivanpah (online 2014) and Crescent Dunes (online 2015, not included in this analysis) use dry and hybrid cooling systems, respectively. Ivanpah consumes and withdraws an estimated total of 3×10^{-2} m^3/delivered GJ (CEC 2010)[276], including an estimated 2×10^{-2} m^3/delivered GJ in wash water.

While Crescent Dunes was not yet online in 2014, the base year for this analysis, its hybrid cooling system represents an interesting data point for inclusion as a side note. A pre-operational estimate for water withdrawal and consumption at Crescent Dunes' hybrid system is 0.4 m^3/delivered GJ, including a somewhat higher than usual estimate of about 5×10^{-2} m^3/GJ for mirror cleaning (BLM 2010)[277]. Of note is that Crescent Dunes might be the only operating solar thermal plant in the United States that needs to manage snow at the plant, which could contribute to higher washing requirements. Operational water use data were not available at the time of this analysis, given that the plant has been intermittently online only since late 2015.

Industrial Steam Generation

In addition to the solar thermal power plants operating in the United States as of 2014, there were two US solar thermal facilities generating industrial steam for enhanced oil recovery

(EOR). One, Brightsource's power tower project for Chevron in Coalinga, California, was a pilot project that shut down in 2014 (Brightsource 2015)[278]. The second, GlassPoint Solar's 21Z project for Berry Petroleum in McKittrick, California is a glass-enclosed parabolic trough facility (GlassPoint 2015)[279]. This work assumes that water use associated with this solar EOR is not different from conventional EOR and is captured in the evaluation of water used for EOR under "oil," above, so to avoid double counting, no additional water is associated with solar thermal systems here.

Thermoelectric Power Generation

Thermoelectric power generation refers to electricity generation that converts thermal energy to electricity. For the purposes of this analysis, thermoelectric generators include steam cycle and combined cycle generators, as these power-producing facilities generally require a cooling fluid to condense steam exiting the steam turbine portion of power cycles.

Data and Approach

Here we describe our methods in determining water withdrawals, water consumption and thermal water quality transformations by cooling water source type (groundwater, surface water, and reuse) and cooling water source quality (freshwater, brackish water, and saline water) for the following fuel categories used for thermoelectric power generation in 2014:

- Natural gas
- Coal
- Nuclear
- Other carbon-based fuels

Note that nonbiomass thermoelectric renewable energy generation data for geothermal and solar thermal power generators are described separately in their respective sections above, given the small number of plants involved.

The following data sources were used to collect power plant-specific data, including primary fuel source(s), annual net power generation, cooling system type, cooling water source, and cooling water source quality.

- *2014 EIA Power Plant-specific Primary Energy Consumption Data, Data Source: EIA 923 for year 2014*[1]
    - File: EIA923_Schedules_2_3_4_5_M_12_2014_Final_Revision
    - Worksheet: "Page 5 Fuel Receipts and Costs," Fuel Receipts and Cost Time Series File, 2014 Final Release, Sources: EIA-923 and EIA-860 Reports.
    - Available at http://www.eia.gov/electricity/data/eia923/

- *2014 EIA Net Power Generation per Power Plant, Data Source: EIA 923 for year 2014*[1]
    - File: EIA923_Schedules_2_3_4_5_M_12_2014_Final_Revision
    - Worksheet: "Page 4 Generator Data," EIA-923 Monthly Generating Unit Net Generation Time Series File, 2014 Final Release, Sources: EIA-923 and EIA-860 Reports
    - Available at http://www.eia.gov/electricity/data/eia923/

- *2014 EIA Cooling Water System and Source Data, Data Source: EIA 860 for year 2014*[248]
    - EIA Cooling Equipment Data Sheet: 6_2_EnviroEquip_Y2014.xlsx
    - Worksheet: "Cooling," 2014 Form EIA-860 Data - Schedule 6, 'Cooling System Data'
    - Available at http://www.eia.gov/electricity/data/eia860/

- *2010 USGS Thermoelectric Power Plant Cooling Water Data, Data Source: USGS Thermoelectric Power Plant Cooling Data*[280]

    - Timothy H. Diehl and Melissa A. Harris (2014). Withdrawal and consumption of water by thermoelectric power plants in the United States, 2010. Scientific Investigations Report 2014-5184
    - Plant-specific data available in Appendix
    - http://pubs.er.usgs.gov/publication/sir20145184

- *2008 Union of Concerned Scientists Thermoelectric Power Plant Cooling Water Data, Data Source: UCS EW3 Energy-Water Database V.1.3.*[281]
    - Union of Concerned Scientists. 2012. UCS EW3 Energy-Water Database V.1.3.
    - Available at www.ucsusa.org/ew3database

<u>Electricity Generation Unit Classification</u>

The EIA-923 form provides monthly data regarding primary energy sources consumed and electricity generated by each generation unit at each power plant in the US, greater than 1MW and connected to the grid. A single power plant typically has several generation units, which are classified in the 923 form by prime mover (i.e. steam turbine, combustion turbine, etc.). Annual fuel use, net generation, and prime mover classifications were characterized for each generation unit level according to Generator ID and Power Plant ID number.

<u>Cooling Technology, Cooling Fluid Source, and Cooling Source Quality Classification</u>

The EIA-860 form reports data regarding the cooling system(s) for each power plant by Cooling System ID number, which does not correspond to Generator ID number. Although EIA offers many cooling system type codes, we classify systems into six categories to reduce error in estimating fractional breakdowns for power plants with several cooling systems:

- once-through cooling (included EIA categories: *Once through with cooling pond* and *Once through without cooling pond*),
- recirculating cooling tower (included EIA categories: *Recirculating with forced draft cooling tower, Recirculating with induced draft cooling tower* and *Recirculating with natural draft cooling tower*)
- recirculating cooling ponds (included EIA categories: *Recirculating with cooling pond or canal*)
- hybrid cooling (included EIA categories: *Hybrid: cooling pond(s) or canal(s) with dry cooling*, *Hybrid: forced draft cooling tower(s) with dry cooling*, *Hybrid: induced draft cooling tower(s) with dry cooling*)
- dry cooling
- no cooling/not applicable

In cases when a power plant only has one cooling system, all of its generation units were assigned a fractional allocation of "1" for cooling system type to signify that 100% of the generation produced in each unit was cooled with that technology. However, in cases when power plants have multiple cooling systems, a fractional value was assigned to each of its units as an estimation of the amount of generation cooled by each system type. Given EIA reporting conventions in the EIA-923 form, generation could not be easily assigned to each cooling system as Generator ID and Cooling System ID are not aligned within a power plant. (For example, multiple generation units can be cooled with a single cooling system.) Thus, for power plants with multiple Cooling System ID numbers, the ratio of consumed water to withdrawn water (i.e., C:W) was calculated at the power plant level based on the USGS's *Withdrawal and consumption of water by thermoelectric power plants in the United States, 2010* (Diehl and Harris 2014)[280], which provides water consumption data and water withdrawal data for US power plants. Based on this ratio, the relative fraction of generation cooled by each cooling technology was assumed and attached to the corresponding Generator ID:

- C:W <0.5: 75% Once-through Cooling; 25% Recirculating
- C:W >0.5: 25% Once-through Cooling; 75% Recirculating

These ratios reflect the fact that in once-through cooled power plants, most water that is withdrawn is returned to the cooling reservoir (i.e., a low C:W ratio), while in recirculating cooled power plants, most water that is withdrawn is lost to evaporation (i.e., a high C:W). For power plants that only utilize recirculating cooling systems, C:W ratios are typically about 0.7, based on USGS data. For power plants that only utilize once-through cooling systems, C:W ratios are typically less than 0.02. Although there is error inherent in this assumption, only a small percentage of power plants have multiple cooling systems, so it is not expected that this assumption affects system-scale results. Large plants reporting multiple cooling systems were analyzed on a case-by-case basis to reduce error amongst the plants that contribute significant generation to a region.

In addition to cooling system type, cooling fluid source type (i.e. groundwater, surface water, plant discharge water, and other) and cooling fluid source quality (freshwater, brackish water, saline water, reclaimed water, and other) were characterized for each Cooling System ID classification based on the EIA 860 form.

Cooling technology, cooling fluid source and cooling fluid source quality data are generally provided by the facilities reporting to the EIA with formal code designations; however, data are not always complete for all generators. A series of additional databases were used to cross-check data and fill in data gaps. First, the EIA-923 form[1] includes a section for generators to enter their specific cooling water source (e.g., Mississippi River) so these data were used to corroborate the 860 data wherever possible. This database was particularly helpful for identifying the cooling water sources of smaller generators that are not required to formally report to EIA. Additionally, an appendix of 2010 water withdrawal and consumption data published by USGS[280] based on Plant ID was used as a second source to confirm data consistency and accuracy, as USGS data also include cooling water technology type, cooling fluid source type code and cooling fluid source quality code classifications for each power plant. Finally, a database published in 2012 by the Union of Concerned Scientists's (UCS)[281] was used as a third data source to cross-check assumptions made regarding EIA and USGS data. This database details annual water withdrawals, consumption, cooling system technology, and cooling fluid source/ quality type by plant ID for the year 2008. Although the UCS database is based on EIA data, it has been heavily vetted and annotated through external peer-review by experts across UCS staff, national labs and academia.

<u>Harmonization of Data Sources</u>

The goal of synthesizing data from the sources described above was to characterize the cooling fluid requirements of every power plant with capacity greater than 1 MW operating in the US in 2014. After all data were manipulated and cross-checked across references as described above, data captured for each Power Plant ID number included (1) net power generation, (2) fuel consumption by fuel type(s), (3) cooling system(s) technology type, (4) cooling fluid source type and (5) cooling source quality type.

For generation units that had only one primary fuel type and/or were cooled within a power plant reporting only one cooling system type, allocating generation was not difficult. For example, Table S15 shows a complete data record for a nuclear power plant.

Table S15. A complete data record for a single power plant

EIA Plant ID	2014 Net Generation (MWh)	Fuel Type, X	Fraction of Gen from X	Gen from X	Cooling System Type, Y	Fraction of Gen from Y	Gen from Y	Cooling Source	Cooling Source Quality
6099	16,985,978	Uranium	1	16,985,978	Once-through	1	16,985,978	Ocean	Saline

Source: Adapted from EIA 923 (EIA 2015)[1]

However, in the case that a power plant used multiple fuels (e.g., fuels "A" and "B") and multiple cooling water systems (e.g., systems "D" and "E"), it is not possible to determine the fraction of generation produced with each primary fuel-cooling system combination (e.g., generation from primary fuel, A, and cooling system, D, versus primary fuel, B, and cooling system, D). Thus, fractional breakdowns were assigned equally, so that, for example, equal amounts of generation from A and B are cooled with cooling systems D and E. Although this assumption is not ideal, most power plants are not subject to this assumption, so associated error is likely low. Since each unit of generation reported in the EIA data is directly attached to a generation unit, and thus, a fuel and prime mover identifier in the database, any potential error takes the form of associating a unit of generation with an incorrect cooling system classification. In other words, the generation tallied for each fuel type and each prime mover is identical to EIA's databases, but some error is inherent in the generation estimated to be cooled by each technology. However, this error is assumed to be small, as the majority of generation produced in 2014 could be characterized without the need for assumptions.

After generation data for each power plant was disaggregated according to primary fuel source, cooling system type, cooling source type, and cooling source quality type, data were re-aggregated according to primary fuel type across the whole US. The major categories addressed in this portion of the analysis include natural gas, coal, nuclear, and other carbon-based fuels. Within each of these categories, data were translated into fractional breakdowns of cooling system type, cooling water source and cooling water source type for each unique fuel-prime mover category. These fractional breakdowns were used to fill in missing cooling technology and/or cooling fluid source characterizations for thermal power plants that did report data, based on other generators of the same fuel-prime mover category. Then these assumptions were checked line-by-line for accuracy and known trends and shifted accordingly. For example:

- once-through cooled coastal power plants typically use ocean water
- once-through facilities typically do not use reclaimed water or groundwater
- recirculating tower cooled facilities generally do not use ocean water for cooling

Since the aggregated generation for thermoelectric power plants reporting no cooling technology or source data is very small, these assumptions are not likely to significantly affect results.

Top-down Analysis at the National Scale to Determine Water Consumption and Withdrawals

At this point the analysis transitioned from a bottom-up analysis (power plant level) to a top-down analysis using annual EIA data (national level). A spreadsheet was set up to compare up to three water consumption and water withdrawal intensities (i.e. volumetric water per unit of generation) for each generation unit record (Table S15). The most appropriate intensity values based on Peer and Sanders (2016)[282], Macknick et al. (2012)[221], and the USGS database (Diehl and Harris 2014)[280] were attached to each record based on fuel, prime mover, and cooling system classification. The Peer and Sanders (2016)[282] database reflects unit-specific cooling water usage intensities calculated from data reported by power plant operators to the EIA for the year 2014. The Macknick et al. (2012)[221] database characterizes water consumption and water withdrawal intensities according to fuel, prime mover, and cooling system classifications, based on a few case studies, so this database represents vetted data for a few characteristic plants. Finally, the USGS database does not characterize prime movers but does offer plant-specific data for a selection of US power plants (Diehl and Harris 2014)[280]. Unlike EIA data, which reflect reported data, the annual cooling water withdrawals and consumption estimates at the power plant level included in the USGS database are based on its own independent heat budget models, so this database was also used to determine reasonable bounds for water withdrawals and water consumption reported to the EIA.

Water consumption and withdrawal intensities from the Peer and Sanders (2016)[282] database were used whenever reported data were reasonable compared to other units of similar configuration. When reasonable data were not available, the Macknick et al. (2012)[221] database was used to assign average water usage rates based on technology configuration. In a few cases, the USGS database was used in instances of complex technology configurations, when generic characterizations could not be made. There are a few reasons why average water withdrawal factors from Macknick et al. (2012)[221] were applied in some cases, rather than using plant-specific water withdrawal data from EIA (compiled by Peer and Sanders, 2016)[282] or USGS (Diehl and Harris 2014)[280]. Although EIA water withdrawal and consumption data are available based on self-reported information by each power plant, analysis of thermodynamic feasibility and comparison to peer-reviewed data suggests some reported data are inaccurate and can span 3-4 orders of magnitude for power plants of similar configurations. USGS data are reported based on thermodynamic heat budget models, so values are generally reasonable. However, USGS data are not available for a significant percentage of generators, do not specify prime mover technology, and classify many power plants as “complex,” which challenges evaluation based on cooling system configuration, but helped characterize units cooled by multiple cooling systems.

Once the most appropriate water withdrawal and water consumption intensity estimates were assigned to each generation unit, they were multiplied by generation to determine a unit-specific estimate for annual water withdrawals and water consumption, respectively.

Reallocation

The EIA 923/860 forms[1,248] include three fuel categories that are not easily allocated to one of the 17 fuel cycles assessed in this work: “OTH” (other), “WH” (waste heat), and “PUR” (purchased). The worksheet “Allocation of “other” fuels” in Data File S1 shows the manual reallocation of these fuels to one of the assessed fuel cycles. This allocation proceeds by subjective assessment of the likely fuel source, supported by web searches of the plants’ names and geographies, including proximity to likely suppliers of purchased power or waste heat. These fuels account for an estimated 0.2% of power plant water withdrawals, so while uncertainty about allocation is high, the influence is small.

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