An Estimate of the Near-Term Electricity Generation Potential of Co-Produced Water From Active Oil and Gas Wells

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Geothermal, electricity, co-produced water, oil, gas, low temperature

ABSTRACT

Co-produced water is water produced as a by-product during oil and gas production. Previous studies have estimated that 15-25 billion barrels of water are co-produced during oil and gas operations annually in the United States. Some well fields produce enough water at high enough temperatures that they could be used to produce electricity. Further, some have speculated that the total electricity generation potential of co-produced water resources in the United States could be tens of gigawatts. This study estimates the near-term market electricity generation potential of water produced as a by-product from active oil and gas operations.

The study focuses on the near-term market potential of the co-produced resource and only considers co-production from existing oil and gas operations. A database consisting of oil and gas well data from across the United States was created by aggregating information from state oil and gas well databases. In all, oil and gas databases from 24 states determined to have significant oil and gas activity were aggregated, resulting in a co-production database containing records from 2.5 million wells, half a million of which were identified as active, producing wells. Then, a Geographic Information System (GIS) was developed to combine oil and gas well location, depth, and water production information with geothermal resource maps to estimate the co-produced water temperature. Co-produced water temperatures were estimated based on maps created from a separate database containing the bottom-hole temperature of 27,000 wells and from temperature-at-depth maps developed by the Southern Methodist University Geothermal Laboratory. Models were developed to calculate the power generation potential of the co-production resource based on the co-produced water volume and temperature estimates. A cut-off temperature for electricity production of 176° F (80° C) was assumed. Several scenarios were explored to determine the sensitivity of the resource potential estimate to assumptions and results from the study.

Over 60% of active wells in the database were found to have estimated temperatures of less than 176° F (80° C). Nearly 20% of the active wells lack sufficient data (primarily well depth) to make a temperature estimate. Although the study indicates that there are a significant number of oil and gas operations with sufficient temperatures and co-produced water volumes that could potentially be utilized for electricity generation, it was concluded that the near-term market potential for the co-production resource as a whole is roughly 300 MW_e. This estimate does not take into account practical operational factors such as a minimum power plant size, availability of cooling water or transmission, project economics, etc., that could further limit the number of sites that could be developed. The majority of the co-production resource potential is in Texas, which accounts for roughly two-thirds of the near-term electricity generation potential. Given the size of the Texas co-produced resource potential relative to the rest of the United States and that co-produced water data for Texas was based on reported re-injected water volumes, a more thorough study based on actual well data is recommended.

Introduction

When oil and gas are produced from underground rock formations, water is often brought to the surface as well. This water is known as "co-produced" water. The management of water from oil and gas production is a direct cost to well field operators and costs more than all other well services combined (Curtice and Dalrymple, 2004). Once the cost of managing and disposing of the water outweighs the profits from oil production, the well is closed. Oil and gas companies design fields and operations to limit the amount of water produced. Despite this, previous studies place the amount of water co-produced in the United States during oil and gas production at between 15-25 billion barrels (bbl) per year (Curtice and Dalrymple, 2004; Veil and Clark, 2009).

There are some potential beneficial uses of co-produced water. Some well fields produce enough water at high enough temperatures to produce electricity using an organic Rankine cycle (ORC) or binary power plant. Adding this type of electricity generation could generate additional revenue for operators (or reduce operating expenses), increase the life of the well field, and decrease the carbon footprint of the field. The concept has already been shown to be technically feasible by a demonstration co-production system that was put into operation at the Rocky Mountain Oilfield Testing Center (RMOTC) near Casper, Wyoming, starting in September 2008. The system makes use of roughly 40,000 barrels per day of co-produced water at temperatures of up to 198° F (92° C) to power a 250 kilowatt (kW_e) ORC plant (Reinhardt, Johnson et al., 2011).

Currently, the total U.S. co-produced resource electricity generation potential is not well understood. Previous studies have attempted to show the potential of the co-produced water resource by noting the large volumes of water co-produced with oil and gas and making general assumptions about the temperature of the co-produced water to show the electrical generation potential of this resource *if* it were actually being produced at a uniform assumed temperature (McKenna, Blackwell et al., 2005; MIT 2006, Chapter 2). The co-produced electricity generation potential from these studies ranges from around 1 gigawatt (GW_e) (McKenna, Blackwell et al., 2005) to over 20 GW_e (MIT 2006), depending on the states included and co-produced water temperatures assumed. A literature survey found no studies that attempted to account for actual wellhead temperatures when evaluating the co-production resource.

This study provides an estimate of the co-produced water electricity generation potential that does take into consideration the wellhead temperature of oil and gas wells. The study focuses on active wells that are currently producing oil and gas and attempts to estimate the volume of co-produced water and wellhead temperature of each individual well based on the location and depth of each petroleum well using available data. In theory, these wells could readily be adapted to produce electricity by adding an ORC power plant that extracts thermal energy from the co-produced water and converts it to electricity. The study is not meant to be an exhaustive or comprehensive review of the geothermal power producing potential from all existing oil and gas infrastructure. It does not consider the geothermal electric production potential from re-opening abandoned or idle wells, reworking existing wells to increase co-produced water production, or any other schemes that aim to enhance the flow rate of co-produced fluids for the purpose of electricity generation outside current conventional oil and gas production. It also does not consider factors that impact the suitability of a well for use in power production, such as fluid quality (corrosiveness, amount of dissolved solids, etc.) or flow rate consistency (constant flow rate vs. intermittent production), or total flow volume. Instead, the study uses available data and resources to produce an order-of-magnitude estimate of the electrical generation market potential of co-produced water in the near-term from existing oil and gas activities.

Methodology

To determine the electricity production potential of a single well, the average flow rate and temperature of the produced fluid must be known. The electricity production potential can then be estimated by calculating the amount of electricity that could be produced from the thermal energy available in the produced fluid. This study estimates the co-produced water resource potential by applying this methodology to oil and gas wells in the United States on a well-by-well basis. To achieve this, the following methodology was used:

1. Build database of existing oil and gas wells
2. Estimate volume of co-produced water for each well in database
3. Estimate temperature of co-produced water for each well in database
4. Estimate electrical generation potential for each well in database
5. Aggregate and analyze results

Details about the specific methodology and results for each step in the general methodology described above are presented below, followed by a discussion of the results and conclusions.

Oil and Gas Well Database Construction: The first step in estimating the co-produced water resource potential was to gather as many records on existing oil and gas wells in the United States as was reasonably possible. There are private companies that maintain large databases of oil and gas records, but they were found to be prohibitively expensive for the volume of data required. Instead, publicly available data from state agencies that track oil and gas activities was collected, cleaned, and aggregated into a single database.

State Oil and Gas Well Databases: Most states have a designated agency that maintains publicly available databases on oil and gas wells that can be obtained for free or at a nominal cost. Due to the time and resources required to obtain and incorporate state well records into a single database, not all oil and gas producing states were considered. Previous studies (Curtice and Dalrymple, 2004; Veil and Clark, 2009) were used as guides to determine key oil and gas production states. Additional spot checking of available well information was done to exclude records from states with wells that were not likely to contribute significantly to the co-produced water resource. For example, both Illinois and Indiana have many wells with significant volumes of co-produced water, but the vast majority of the wells are too shallow to be viable co-produced electricity candidates. Other states had too little oil and gas activity to be considered. The exclusion of these states is not expected to have any impact on the overall co-produced electricity generation potential. The states included are shown visually in Fig. 1. The sources and contacts used to obtain the individual state oil and gas databases are listed in Appendix A.

Well Data Collection and Aggregation: Oil and gas well data sets from each state included in the study were collected for the most recent year available and collated into a single database (referred to as the *co-production database*). Only onshore oil and gas wells were included. To be useful for this study, each well had to have a minimum set of data:

- American Petroleum Institute (API) well identification number
- Well depth
- Well location (latitude and longitude)
- Production volume (oil, gas, and/or water)

If the well did not have at least these four required elements, it could not contribute to the co-production resource estimate.

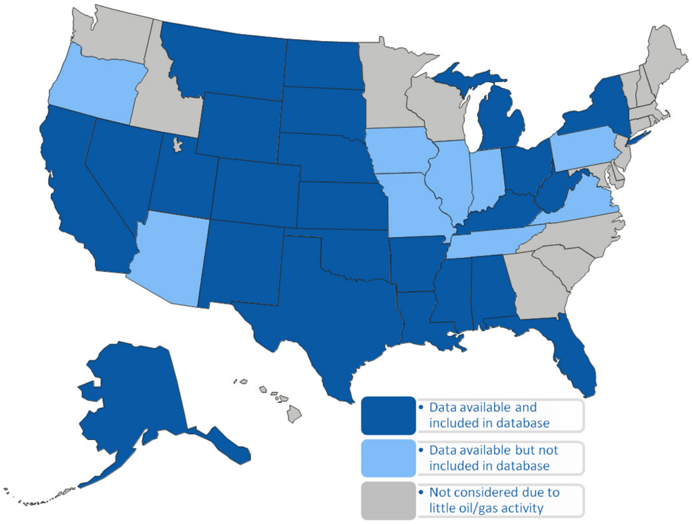

Figure 1. Map of United States showing states with oil and gas databases included in study.

Since this study only considered co-production from active wells, an absence of production data meant the well was not included in the co-produced water resource estimate. An active well was defined as a well with a record of oil, gas, or water production in any combination. Most states have recorded well depths for over 80% of the wells in the state. There are notable exceptions:

- Oklahoma: Oil well records are not recorded publicly. Gas wells, which are managed separately, were used in this report. After consulting with an oil and gas data service provider familiar with the region, it was determined most oil wells are too old and shallow to be considered a co-produced resource and their exclusion should not affect the co-produced water resource estimate.
- California: Over 20,000 wells drilled before 1984 are not digitally available. To include these wells in this study, individual paper logs would have to be examined at the California DOGGR District 4 Office.
- Mississippi: Many records are missing depth data, but mainly apply to inactive wells.
- Louisiana: In the original records, 84% of all wells had well depth data, but only 61% of active wells included depth data. Due to relatively high temperatures of many wells in Louisiana and their importance to the resource potential estimate, estimates of the depths of the wells with missing data were made. Wells that were originally missing depths were assigned the average depth of all the wells in the same field.

In all, the co-production database consists of roughly 2.5 million oil and gas well records. Of these, roughly 500,000 wells are considered "active," or have some record of oil, gas, and/or water production. The locations of the oil and gas wells included in the database are shown in Fig. 2.

Water Production Estimates: Water production from petroleum wells was estimated on a per-well basis. Curtice and Dalrymple (2004) and Veil and Clark (2009) estimated co-produced water volumes from oil and gas wells by state. These references were used as a guide and a starting point to estimate co-produced water volumes. The most recent production data available for each state at the time the study was conducted was used (the total water produced is not a static number but varies from year to year, relative to oil and gas production activity).

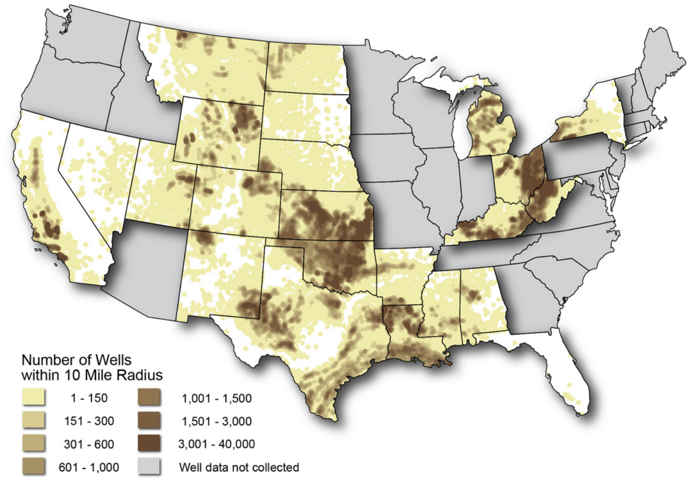

Figure 2. Map showing locations and density of all wells included in co-production database.

Many states collect water production data on a per-well basis, along with oil and gas production. For states where this information was available, the co-produced water data for each well were simply added to the dataset for the well in the co-production database. Other states do not require the amount of produced water to be reported, or do not collect or have available direct data on water production from oil and gas wells. For these states, a method for estimating water production for each well based on available data was created. For states that report the oil and gas production on a per-well basis, the co-produced water was estimated using water-to-oil ratios (WOR) and water-to-gas ratios (WGR) developed by Veil and Clark (2009). The volume of co-produced water for a given well was calculated by multiplying the reported volume of oil and/or gas produced from the well by the corresponding WOR or WGR. Some states do not collect oil and gas production from individual wells (or this study was unable to obtain such information if available), but rather report it by field or county. In these cases, the oil and gas production was divided evenly among the active wells in the field or county, and the water production estimate was based on the WOR and WGR. In Texas, water production data is not reported, but water injection data is. Since nearly all produced water is re-injected, the water production data was estimated based on re-injection data. Water production estimates were made based on consultations with an oil and gas data service provider familiar with production in the state of Texas. Oil wells in Texas were considered to be too shallow and therefore at too low a temperature to be used for electricity generation, so their data was not included in this study. For similar reasons, gas wells with depths <5,000 feet (ft) (<1,524 meters (m)) were also not included. The water produced from these well accounts for nearly 3.3 million bbl of water production. For the gas wells considered, gas production data is reported on a per-well basis. A WOR of 511 bbl of water per million cubic feet (MMcf) of gas was used to estimate the volume of water co-produced from gas

Table 1. WOR and WGR Values Used to Estimate Water Production in States That Do Not Report Water Production on a Per-Well Basis.

State	Oil and Gas Production Data	Water to Oil Ratio (WOR) (bbl/bbl)	Water to Gas Ratio (WGR) (bbl/MMcf)	Sources and Notes
AR	By County	7.6	260	Veil and Clark 2009, Table 4 U.S. Average WOR and WGR used
KS	By Field	21.8	1208	Veil and Clark 2009, Table 4
KY	Per Well	6.4	17.7	Veil and Clark 2009, p. 37
LA	Per Well	13.5	260	Veil and Clark 2009, Table 4 MS WOR and U.S. Average WGR used to match water production estimates in Veil and Clark 2009
MT	By Field	4	51.1 for gas wells 2,976 for coalbed methane wells	Veil and Clark 2009 WOR from Table 4, WGR from text on p. 38
NV	By Field	16.6	n/a	Veil and Clark 2009, Table 4
OK	Per Well	15.26	845	Veil and Clark 2009, Table 4 Assumed WOR and WGR were 70% of KS values to match water production estimates in Veil and Clark 2009
TX	Per Well	n/a	511	MLKay Technologies, LLC (data service) Oil wells considered too shallow to be co-production resource. Only gas wells >5,000 ft deep included. Approximately 3.3 million bbl water produced from shallow wells not included.
WV	Per Well	6.4	17.7	Veil and Clark 2009, p. 37

Table 2. Oil, Gas, and Water Production Estimates in Co-Production Database by State.

State	Source Year for data	All Wells	Active Wells	Crude Oil (bbl/year)	Total Gas (MMcf/year)	Co-Produced Water Estimate, this study (bbl/year)	Co-Produced Water Estimate in 2007 (bbl/year) (from Veil and Clark 2009)
AK	2009	7,635	2,309	235,490,938	3,330,474,131	740,218,875	801,336,000
AL	2009	17,304	6,367	6,450,128	245,291,168	110,284,242	119,004,000
AR	2008	20,979	4,182	3,269,175	447,312,107	141,146,855	166,001,000
CA	2009	200,885	52,055	195,125,920	413,080,561	2,653,300,165	2,552,194,000
CO	2008	89,467	35,114	22,700,670	1,617,761,172	334,730,672	383,846,000
FL	2009	1,268	55	564,134	278,674	10,951,819	50,296,000
KS	2009	407,499	4,041	38,081,593	353,057,005	1,263,934,847	1,244,329,000
KY	2007	114,621	11,998	1,876,924	44,031,686	12,262,536	24,607,000
LA	2009	191,411	10,669	54,176,341	1,374,980,963	1,088,845,115	1,149,643,000
MI	2009	62,870	3,879	5,286,125	148,919,494	102,005,119	114,580,000
MS	2009	32,464	3,723	22,768,805	344,980,675	314,639,592	330,730,000
MT	2008	42,930	10,187	31,551,221	89,859,841	168,353,140	182,266,000
ND	2009	19,197	4,769	78,288,963	91,145,875	153,128,630	134,991,000
NE	2008	21,056	693	2,380,375	3,083,488	49,312,914	49,312,000
NM	2009	95,556	49,417	61,138,742	1,504,413,425	699,549,055	665,685,000
NV	2008	999	87	431,428	0	7,174,590	6,785,000
NY	2008	38,475	10,277	383,445	50,320,021	1,124,494	649,000
OH	2007	261,804	41,639	5,109,973	76,439,490	4,458,065	6,940,000
OK	2008	336,186	75,228	65,067,861	1,430,969,793	2,202,104,747	2,195,180,000
SD	2009	1,859	222	1,544,017	12,704,394	3,938,560	4,186,000
TX[1]	2009	241,543	63,542	0	5,102,217,628	2,607,232,920	7,376,913,000
UT	2009	27,131	9,692	22,922,494	449,508,451	156,176,293	148,579,000
WV	2008	130,496	53,055	2,077,204	252,640,081	17,765,582	8,337,000
WY	2007	111,885	42,497	52,342,627	2,224,227,297	2,229,499,084	2,355,671,000
Totals		**2,475,520**	**495,697**	**909,029,102**	**19,607,697,420**	**15,072,137,911**	**20,072,060,000**

[1] Co-production database only includes gas wells in Texas >5,000 ft (1,524 m) deep. Texas oil wells and shallow gas wells not included account for an additional 3.3 billion bbl/year of co-produced water.

wells. A summary of the WOR and WGR values used to estimate water production for states that do not report water production on a per-well basis is included in Table 1.

Table 2 summarizes the number of wells in the co-production database, the source year for the data, and the estimated volumes of oil, gas, and water produced from those wells per state. The water production estimates were validated against water production figures for 2007 from Veil and Clark (2009), also shown in the table. In general, total water production volume estimates agreed well with the previous studies.

Water Temperature Estimates: Bottom hole temperature (BHT) is routinely recorded on oil and gas well completion logs. This information could be used to estimate the water temperature from an oil and gas well. However, states do not require this information to be reported, so the data is not available in a readable digital form. BHT data is available on paper well logs or electronic copies of the logs. This data is currently being collected (progress on this data collection effort and available datasets can be found at http://www.stategeothermaldata.org) and will be made available digitally as part of the National Geothermal Data System (http://www.geothermaldata.org), but was not available at the time of this study.

In the absence of electronically available BHT data, a novel approach was developed to estimate the temperature of the water produced from oil and gas wells. A Geographic Information System (GIS) was constructed from the co-production database. All wells with geographic information were plotted across the United States. Based on the location and depth of the well, the temperature of the water from the well was estimated by assuming the water is at the same temperature as the formation at the total well depth. Two data sources were used for the temperature-at-depth estimates – temperature-at-depth maps produced by Southern Methodist University (SMU) Geothermal Laboratory for wells deeper than 11,500 ft (3.5 kilometer (km)), and the American Association of Petroleum Geologists (AAPG) BHT database for wells shallower that 11,500 ft (3.5 km).

SMU Temperature-at-Depth Maps: The enhanced geothermal system (EGS) resource maps presented in *The Future of Geothermal Energy* (MIT 2006) were used to estimate co-produced water temperatures from wells deeper than 3.5 km (11,500 ft). These maps, developed by the SMU Geothermal Laboratory from a variety of geothermal databases that included BHT and heat flow measurements (Blackwell and Richards, 2004), estimate the temperature-at-depth for the 48 contiguous United States from 3.5 to 9.5 km (11,500 ft to 31,200 ft) at 1 km (3,280 ft) intervals (see Fig. 3). For this study, a version of the map that includes actual temperature estimates at each depth interval for a given location rather than temperature ranges was licensed directly from the SMU Geothermal Laboratory. The produced water temperature for wells deeper than 3.5 km (11,500 ft) was calculated by comparing the location and depth of each well to the SMU temperature-at-depth maps. The temperature was assigned by linear interpolation between the temperature values from the maps at the intervals above and below the total well depth at a given well location.

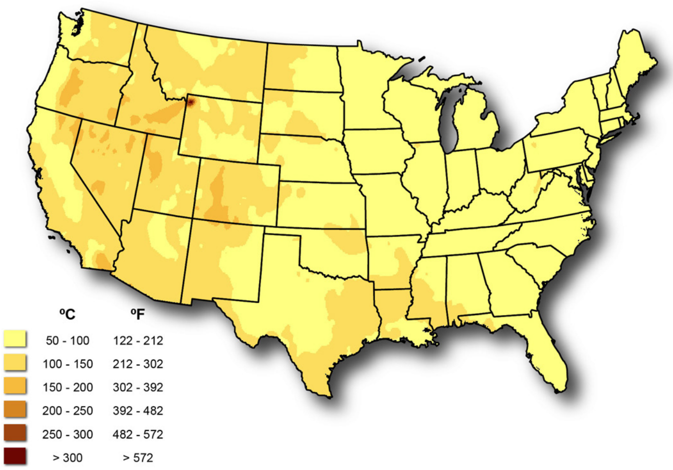

Figure 3. Map of contiguous U.S. states showing temperature ranges at depth of 3.5 km (11,500 ft).

The SMU temperature-at-depth maps were originally envisioned to be the core temperature data source for this study. However, it was found that only about 3% of the wells in the co-production database have depths >3.5 km (>11,500 feet), where the SMU maps can be used. Most of these wells were drilled in the Gulf Coast and Williston Basin. To estimate the temperature of water produced from the remaining wells in the database, a different temperature data source was needed.

AAPG BHT Database: To estimate the temperature of water produced from wells shallower than 11,500 ft (3.5 km), a version of the American Association of Petroleum Geologists BHT database with BHT corrections from SMU was used. The database consists of over 27,000 BHTs compiled by the AAPG in the early 1970s and later converted to digital form (AAPG 1994). The BHT of almost 20,0000 wells in this database were corrected to account for the effect of drilling activities on the temperature measurements by the SMU Geothermal Laboratory (Blackwell and Richards, 2004). The resulting database with corrected BHT (referred to as the AAPG/SMU BHT database) was used for this study. The over 27,000 temperature records were integrated into the co-produced GIS to estimate the temperature of co-produced water for wells shallower than 11,500 ft (3.5 km). A map

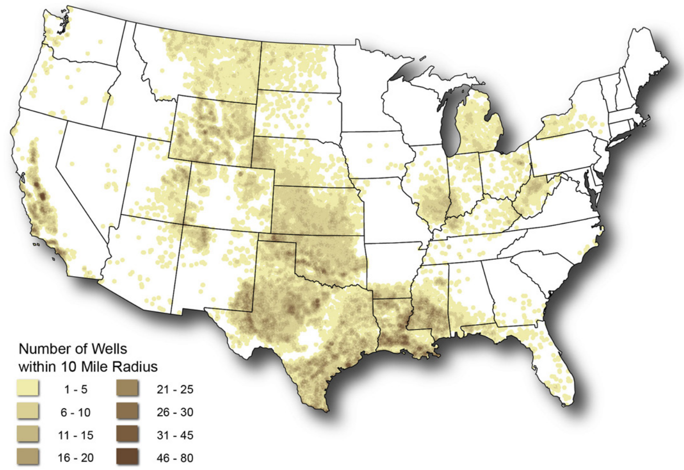

Figure 4. Map showing locations and density of wells in AAPG/SMU BHT database.

showing the locations of the wells in the resulting database is shown in Fig. 4.

Temperature maps were created at 1,640 ft (0.5 km) intervals from 0 to 11,500 ft (0 to 3.5 km) using the AAPG/SMU BHT database. First, all the wells for a given depth interval were mapped. Next, a 10-mile (16 km) buffer zone was created around each well, and the area in that zone was assigned the temperature of the given well, as shown in Fig. 5. In the case of overlapping buffer zones, the buffer zones of each well were truncated to accommodate neighboring wells. The depth intervals and buffer zones were chosen assuming that temperature variations with depth and distance were relatively gradual, so that wells in the same area tended to have similar temperatures. The gradual variation in temperature ranges shown in Fig. 5 validates these assumptions. Areas outside

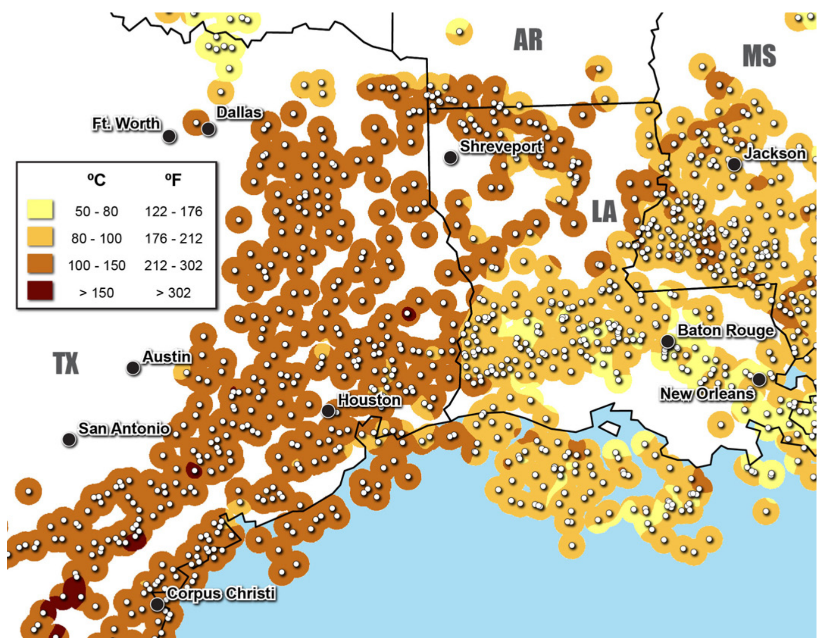

Figure 5. Temperature map showing buffer zones created from wells in BHT database in 9,800-11,500 ft (3.03.5 km) depth interval for Gulf Coast Region. White dots show locations of wells in BHT database.

the buffer zones were excluded from the temperature map. Finally, all oil and gas wells in the co-production database that fell within the temperature map were assigned a temperature equal to the value of the map at the location of the well. This temperature corresponded to the BHT of the nearest neighboring well in the AAPG/SMU BHT database. Any wells in the co-production database that fell outside the temperature maps were not assigned temperatures. This process was repeated to create temperature maps at 1,640 ft (0.5 km) depth intervals. In all, a total of 1,228,894 wells in the co-produced database were assigned a temperature in this way.

The accuracy of well temperature estimates using the methodology described above was validated using a recent study (Blackwell, Richards et al., 2010) that contained BHT temperatures, corrected to account for drilling activities, from almost 5,000 wells in eastern Texas. The difference between the estimated and measured well BHT values were centered around zero and nearly symmetrical, with most of well estimates falling within ±45° F (±25° C) of the measured value, indicating that the method described above does a reasonable job of estimating well temperatures.

Well Temperature Screening Methods: After applying the two temperature estimate methods described above, there were still 401,169 wells in the database with a valid location and depth that lacked a temperature estimate because they were both shallower than 11,500 ft (3.5 km) and outside of the buffer zones of the temperature maps created using the AAPG/SMU BHT database. In an effort to rule out as many wells with insufficient production temperatures for electricity generation as possible, two methods for screening wells by temperature were developed and applied. For both methods, a cut-off temperature of 176° F (80° C) was adopted.

The first method made use of the observation that, as shown in Fig. 3, even at a depth of 11,500 ft (3.5 km) a majority of the United States has an estimated temperature of 212° F (100° C) or less. Using the GIS maps of temperature-at-depth obtained directly from the SMU Geothermal Laboratory, a map of the 176° F (80° C) isotherm was created. By assuming that temperature increases with increasing depth, the map was then used to create a "temperature mask" showing where the temperature was estimated to be below 176° F (80° C) at depths shallower than 11,500 ft (3.5 km). The location of each well in the database lacking a temperature estimate was compared to the <176° F (<80° C) temperature mask. Using this method, it was determined that 118,411 wells in the database likely had temperatures of <176° F (<80° C) based on their depth and location compared to the SMU 3.5 km temperature map and were not likely candidates for electricity generation.

The second method replicates the method above, but extends it to the regions where the temperature is estimated to be >176° F (>80° C) at 11,500 ft (3.5 km) – generally in the Western United States and in Texas. For these regions, a 176° F (80° C) isotherm was created using available data from the AAPG/SMU BHT database. Wells with temperatures between 172° F-180° F (78-82° C) were used to create the isotherm. The second method works by essentially removing the 10-mile buffer radius previously used for the maps created using the AAPG/SMU BHT database. This means that a well could be assigned temperatures based on the data for wells many miles away. The second method was used as a last resort for screening wells in the database. Further data in these regions is needed. As before, the well depth was compared to the depth where the temperature was estimated to be <176° F (<80° C) at the location of each well in the database lacking a temperature estimate. Using this method, 282,757 wells were assigned temperatures. The vast majority were determined to have a temperature of <176° F (<80° C). However, 9,303 wells were found to have depths greater than the 176° F (80° C) isotherm and therefore presumably have temperatures above 176° F (80° C). These wells were assigned a temperature of 176° F (80° C); since it was only a small number of wells, they should not have a large impact on the overall resource potential estimate.

Table 3. Number and Percentage of Wells with Temperature Estimates by Method and Wells without Temperature Estimates (Temperature Unknown) by Reason for All Wells and Active Wells.

	Method/Reason	All Wells		Active Wells	
		Wells	%	Wells	%
Temperature Estimated	AAPG/SMU BHT Database-Based Maps	1,228,894	50%	268,728	54%
	SMU Temperature-at-Depth Maps	83,024	3%	31,224	6%
	SMU Temperature-at-Depth 80ºC Isotherm Screen	118,411	5%	22,852	5%
	AAPG/SMU BHT Database 80ºC Isotherm Screen	282,757	11%	76,906	16%
	Direct BHT Measure[1]	24	0.0%	7	0.0%
Temperature Unknown	Alaska (no temperature data)	6,891	0.3%	2,303	0.5%
	Depth Not Recorded	692,814	28%	79,583	16%
	Location Not Recorded	54,397	2%	13,446	3%
	Offshore Well (no temperature data)	8,308	0.3%	648	0.1%

[1] BHT measurements for wells at Teapot Dome Naval Petroleum Reserve #3 in Wyoming

Water Temperature Estimate Summary: Table 3 summarizes the number and percentage of wells for which each of the temperature estimate methods described above was employed. It also includes a breakdown of the explanations for instances where the temperature of a well in the co-production database could not be estimated. Most wells with temperature estimates relied on data from the AAPG/SMU BHT database, indicating that most oil and gas wells in the database are relatively shallow (<11,500 ft or <3.5 km in depth). Typically, when the temperature of a well could not be estimated, it was because the depth of the well was not recorded in the database.

Electricity Generation Potential Estimates: The amount of electricity that can be generated from a well depends not only on the co-produced water flow rate and temperature, but also on the efficiency of the power plant in converting thermal energy into electrical energy. For this study, it was assumed that ORC (binary) power plants would be used to generate electricity from the co-production resource. To capture the potential variability in power plant efficiencies, the electricity generation potential of the co-produced resource was estimated using three models:

1. *Exergy (theoretical maximum power potential)*: the theoretical maximum power potential is thermodynamically limited. The maximum amount of work that can be extracted from the fluid resource relative to the ambient environment (dead state) is called the exergy or availability of the fluid.
2. *MIT model*: the MIT model is based on the thermal efficiency defined by Equation 7.1 in the MIT-led *Future of Geothermal Energy* report (2006).
3. *Commercially available "Off-the-Shelf" (COTS) model*: the COTS model is based on the power performance curves published for the commercially available Pratt & Whitney Model 280 PureCycle power system (Pratt & Whitney, 2011).

Exergy - Theoretical Maximum Power Potential: The exergy, Ė, is the theoretical maximum amount of work that can be extracted from the co-produced water. This calculation gives an upper limit for the co-produced resource potential. The theoretical maximum power that could be extracted from a fluid relative to the ambient or dead state is defined as:

$$\dot{E} = \dot{m}\left[\begin{array}{l}\left(H\left(T_{in}\right) - H\left(T_{ambient}\right)\right) - \\ T_{ambient}\left(S\left(T_{in}\right) - S\left(T_{ambient}\right)\right)\end{array}\right] \quad (1\}$$

When calculating enthalpy and entropy, it was assumed that the co-produced resource is pure water and pressure effects were ignored so that enthalpy and entropy are functions of temperature only. An ambient temperature of 50° F (10° C) was assumed.

MIT Model: The *Future of Geothermal Energy* report (MIT 2006) included one of the first calculations of the U.S. electricity generation potential from co-produced resources. Their analysis assumed that binary plants would be used for power generation, and based the power generation potential on a correlation for the thermal efficiency, η_{th}, derived from data from existing hydrothermal binary plants with operating temperatures between roughly 212-392° F (100-200° C). The thermal efficiency is defined as the ratio of the net rate of work output of the power plant to the net rate of heat input into the power plant:

$$\eta_{th} = \frac{\dot{W}}{\dot{Q}} \quad (2)$$

The thermal efficiency represents the amount of thermal energy input into the power plant that is converted to useful work. The rate of heat input to the power plant is calculated from the change in enthalpy of the resource fluid between the inlet and outlet of the power plant:

$$\dot{Q} = \dot{m}\left[H\left(T_{in}\right) - H\left(T_{out}\right)\right] \quad (3)$$

The correlation for the thermal efficiency used in their analysis, defined in Equation 7.1 of the MIT report (2006), is:

$$\eta\text{th} = 0.0935{*}\text{T}(°\ \text{C}) - 2.3266 \quad (4)$$

For this report, the same model used in the MIT report for estimating the co-produced resource power potential was adopted and is referred to as the "MIT Model." Eq. 2 through Eq. 4 were used to calculate the power potential of the co-produced resource. As with the exergy calculation, it was assumed that the co-produced resource is pure water and pressure effects were ignored so that enthalpy is a function of temperature only. A plant outlet temperature of 95° F (35° C), the outlet temperature that appears to be used in the MIT report, was assumed. The MIT model was validated against the results presented in Table 7.3 of the MIT report (MIT 2006, Table 7.3) and was found to be within agreement by 2% or better over a temperature range of 212-356° F (100-180° C). The model is included so that the results of this study can be compared directly to the co-produced water resource potential estimates in the *Future of Geothermal Energy* report (MIT 2006).

COTS Model: The final model considered was based on Pratt & Whitney's Model 280 PureCycle power system, a commercially available "off-the-shelf" ORC power plant that uses R245fa (pentafluoropropane) as the binary working fluid. The Model 280 PureCycle is designed to use heat sources from 195° F to 300° F (91° C to 149° C) to generate a gross power output of up to 280 kW_e and a net output of up to 260 kW_e (Pratt & Whitney, 2011). The published performance characteristics of the PureCycle power system (Pratt & Whitney, 2011) were used to create a model, referred to as the "COTS model," to estimate the electric power production potential from co-produced resources. The Model 280 PureCycle power system was chosen due to the availability of its performance characteristics and the likelihood that, as a commercially-available stand-alone power system, it could be used for electricity production from co-production systems[1]. The performance curves were used to calculate the power output from the Model 280 PureCycle power system as a function of resource temperature on a per-unit resource fluid basis. It was assumed that 50° F (10° C) cooling water is available, and that the net power output from the power system is 260 kW_e.

The COTS model calculates the power potential of a given co-produced water resource by multiplying the co-produced resource flow rate by the per-unit fluid power output as a function of resource temperature. In applying the model, no restriction was put on the size of the system. In effect, the model assumes that a power system is available with the performance characteristics of the Model 280 PureCycle system but that is sized specifically for a given co-production resource. The performance curves only cover a temperature range of 190-300° F (88-149° C). It was found that over this temperature range, the COTS model matches well with the MIT model with an assumed plant outlet temperature of about 170° F (76° C); therefore, for co-production resources outside the stated operating temperature range, the COTS model uses the results of the MIT model assuming a plant outlet temperature of about 170° F (76° C).

Model Comparison: Table 4 shows a comparison of the estimated power generation potential resulting from the three models used in this study as a function of resource temperature, assuming 10,000 bbl/day of co-produced fluid. The exergy gives the theoretical maximum power potential for the resource and therefore always gives the highest (upper bound) estimate. In reality, no co-production system would ever approach this upper bound. The MIT model gives the second highest estimate because it assumes a significantly lower power plant exit temperature than the COTS model. This also explains why at lower resource temperatures the MIT model results in a much higher estimated power potential that the COTS model; at low temperatures, the

Table 4. Comparison of Results from Power Generation Potential Models Used in Study as a Function of Resource Temperature.

Resource Temperature		Power Potential (kW_e) per 10,000 bbl/day[1] Co-Produced Water Flow		
(°F)	(°C)	Exergy	MIT Model	COTS Model
176	80	569	176	24.3
212	100	910	349	148
257	125	1,429	646	355
302	150	2,043	1,037	620
347	175	2,749	1,525	1,025
392	200	3,546	2,112	1,531

[1] 10,000 bbl/day = 292 gal/min or 18.4 kg/s (assumed that density of co-produced water = 1 kg/liter)

MIT model assumes it can extract much more thermal energy from the co-produced water than the COTS model. As the resource temperature increases, the effect of the differing exit temperature assumptions is diminished and the estimated power potentials are more comparable. The table shows that the COTS model gives the lower bound estimate for the study.

Results

Temperature Estimates by Well: While there are almost 2.5 million wells in the co-production database, Table 5 shows only 11.3% have an estimated temperature of ≥176° F (≥80° C). The table shows the majority of U.S. oil and gas wells produce fluids that are likely too low in temperature to be used for electricity generation. About 31% of the wells in the database have an unknown temperature, due mostly to missing well depth data. From the table, it can be seen how the estimated temperature tends to increase with well depth. A similar story emerges when only active wells are considered. Table 6 shows that only about 20% of all active wells (100,865) are estimated to produce water with temperatures >176° F (>80°C). This is a higher percentage than when all wells are considered, but still a relatively small number. Moreover, the well count drops rapidly as the estimated temperature increases. The number of active wells that do not have an estimated temperature associated with them is still significant at about 20%, but makes up a smaller percentage than in the case of all wells.

Temperatures Estimates by Co-Produced Water Volume: Table 7 gives a summary of the volume and percentage of co-produced water from the wells in the database by temperature and depth interval. Nearly half of the co-produced water volume is estimated to have a temperature below 176° F (80° C), making it unlikely that it could be used to generate electricity. The volume of co-produced water decreases quickly as the temperature rises. As before, it can be seen how

Table 5. Number and Percentage of All Wells in Database by Depth and Temperature Intervals.

		Estimated Temperature									
Depth Range		<176°F	176-212°F	212-257°F	257-302°F	302-347°F	347-392°F	>392°F	*Unknown*		
ft	*km*	*<80°C*	*80-100°C*	*100-125°C*	*125-150°C*	*150-175°C*	*175-200°C*	*>200°C*		**Totals**	
0-1,600	0-0.5	338,686	3	1					24,829	**363,519**	**14.7%**
1,600-4,900	0.5-1.5	722,205	164	31					14,085	**736,485**	**29.8%**
4,900-8,200	1.5-2.5	316,440	64,524	5,223	173				11,870	**398,230**	**16.1%**
8,200-11,500	2.5-3.5	50,266	77,500	42,872	11,567	274			6,379	**188,858**	**7.6%**
11,500-14,800	3.5-4.5	5,853	21,421	20,319	17,171	693	5	3	9,074	**74,539**	**3.0%**
14,800-18,000	4.5-5.5	17	2,420	5,189	3,722	2,398	10	2	2,748	**16,506**	**0.7%**
18,000-21,300	5.5-6.5		407	1,100	715	541	599	8	516	**3,886**	**0.2%**
21,300-24,600	6.5-7.5		26	293	98	27	30	17	90	**581**	**0.0%**
24,600-27,900	7.5-8.5			1	25	2	8	8	5	**49**	**0.0%**
27,900-31,200	8.5-9.5			1	5	2	1	2		**11**	**0.0%**
>31,200	>9.5					42				**42**	**0.0%**
Unknown										**692,814**	**28.0%**
	Totals:	**1,433,467**	**166,465**	**75,030**	**33,476**	**3,979**	**653**	**40**	**762,410**	**2,475,520**	
		57.9%	**6.7%**	**3.0%**	**1.4%**	**0.2%**	**0.0%**	**0.0%**	**30.8%**		

Table 6. Number and Percentage of Active Wells in Database by Depth and Temperature Intervals.

		Estimated Temperature									
Depth Range		<176°F	176-212°F	212-257°F	257-302°F	302-347°F	347-392°F	>392°F	*Unknown*		
ft	*km*	*<80°C*	*80-100°C*	*100-125°C*	*125-150°C*	*150-175°C*	*175-200°C*	*>200°C*		**Totals**	
0-1,600	0-0.5	54,791							1,106	**55,897**	**11.3%**
1,600-4,900	0.5-1.5	147,614	13	13					5,273	**152,913**	**30.8%**
4,900-8,200	1.5-2.5	81,809	25,949	3,327	133				5,938	**117,156**	**23.6%**
8,200-11,500	2.5-3.5	11,672	20,792	14,566	7,590	157			2,366	**57,143**	**11.5%**
11,500-14,800	3.5-4.5	2,964	6,727	5,919	8,445	373	1	1	1,405	**25,835**	**5.2%**
14,800-18,000	4.5-5.5	2	1,494	885	1,303	1,454	5		237	**5,380**	**1.1%**
18,000-21,300	5.5-6.5		174	331	136	334	531	1	47	**1,554**	**0.3%**
21,300-24,600	6.5-7.5		5	125	18	4	14	11	21	**198**	**0.0%**
24,600-27,900	7.5-8.5				10		1	3	4	**18**	**0.0%**
27,900-31,200	8.5-9.5				3		1			**4**	**0.0%**
>31,200	>9.5					16				**16**	**0.0%**
Unknown										**79,583**	**16.1%**
	Totals:	**298,852**	**55,154**	**25,166**	**17,638**	**2,338**	**553**	**16**	**95,980**	**495,697**	
		60.3%	**11.1%**	**5.1%**	**3.6%**	**0.5%**	**0.1%**	**0.0%**	**19.4%**		

Table 7. Volume (in Thousand Bbl/Year) and Percentage of Co-Produced Water in Database by Depth and Temperature Intervals.

Depth Range		Estimated Temperature									
		<176°F	176-212°F	212-257°F	257-302°F	302-347°F	347-392°F	>392°F	*Unknown*	Totals	
ft	*km*	*<80°C*	*80-100°C*	*100-125°C*	*125-150°C*	*150-175°C*	*175-200°C*	*>200°C*			
0-1,600	0-0.5	1,385,671							51,793	**1,437,465**	**9.5%**
1,600-4,900	0.5-1.5	3,523,414	217	151					218,840	**3,742,622**	**24.8%**
4,900-8,200	1.5-2.5	1,881,828	562,420	37,189	118				128,530	**2,610,084**	**17.3%**
8,200-11,500	2.5-3.5	381,022	802,379	496,382	273,323	11,637			342,006	**2,306,748**	**15.3%**
11,500-14,800	3.5-4.5	89,504	462,577	276,287	499,786	54,000	1		325,817	**1,707,971**	**11.3%**
14,800-18,000	4.5-5.5	39	177,822	141,706	115,920	136,074	226		61,144	**632,933**	**4.2%**
18,000-21,300	5.5-6.5		26,951	74,664	8,463	22,712	13,147		12,468	**158,405**	**1.1%**
21,300-24,600	6.5-7.5		1,798	30,923	3,092	92	404	893	8,359	**45,560**	**0.3%**
24,600-27,900	7.5-8.5				1,862		10	628	158	**2,659**	**0.0%**
27,900-31,200	8.5-9.5				1,148		29			**1,177**	**0.0%**
>31,200	>9.5					426				**426**	**0.0%**
Unknown									2,426,089	**2,426,089**	**16.1%**
	Totals:	**7,261,477**	**2,034,164**	**1,057,302**	**903,712**	**224,940**	**13,816**	**1,521**	**3,575,205**	**15,072,138**	
		48.2%	**13.5%**	**7.0%**	**6.0%**	**1.5%**	**0.1%**	**0.0%**	**23.7%**		

project economics, etc., were not considered when estimating the co-produced water resource potential.

Table 8 shows the co-produced water resource electricity generation potential by temperature interval. The estimated theoretical maximum potential for the wells in the database, given by the exergy, is about 1,300 MW_e. This value shrinks to 560 MW_e when the MIT model is used, and further diminishes to 276 MW_e for the COTS model. This demonstrates how practical considerations, such as power plant efficiency and limitations on the plant exit temperature of the co-produced water, impact the resource estimate. Table 8 shows that for all the models used, the greatest resource potential lies in the 257-302°F (125-150°C) range, despite the fact that the volume of co-produced water available continually decreases as the temperature decreases. This can be explained by referring to Table 4. At low temperatures, the co-produced fluid has less power production potential on a per unit fluid basis, so that greater volumes are needed to produce a given amount of power. Up until 302°F (150°C), the increase in power production potential with rising temperature is enough to overcome the decrease in the volume of fluid available at these temperatures and results in a larger total potential. The volume of co-produced fluid with estimated temperatures above 302° F (150° C) drops sharply, so that the relative amount of total resource potential at these temperatures decreases as well.

the estimated temperature tends to increase with well depth. Nearly a quarter of the co-produced volume of water does not have an estimated temperature associated with it in the database, primarily due to missing well depth data. Over 85% of the co-produced water volume with an unknown temperature in the co-production database comes from just three states: California (1,635 million bbl/year with unknown temperature), Alaska (740 million bbl/year), and Oklahoma (722 million bbl/year).

Electricity Generation Potential Estimate: An estimate of the electricity generation potential of the co-produced resource for the wells in the co-production database was made using each of the models described above. Co-produced water resources with estimated temperatures of less than 176° F (80° C) were not considered viable for electricity generation and were excluded from the resource estimate. The cut-off temperature was chosen based on the minimum operating temperatures of several commercially available binary power plants. Other than the cut-off temperature, no restrictions were placed on the wells for the resource estimate. Factors such as a minimum or continuous flow of co-produced water, a minimum power generation potential (i.e., a minimum power plant size), access to electricity transmission, or a local demand for the electricity, cooling water availability,

Table 8. Estimated Co-Produced Resource Electricity Generation Potential by Temperature Interval.

Temperature Interval		Wells	Active Wells	Co-Produced Water	Exergy	MIT Model	COTS Model
(°F)	**(°C)**			**(bbl/year)**	**(kW_e)**	**(kW_e)**	**(kW_e)**
<176	<80	1,433,467	298,852	7,261,477,447	-	-	-
176-212	80-100	166,465	55,154	2,034,163,562	395,413	137,466	40,783
212-257	100-125	75,030	25,166	1,057,302,366	323,092	134,929	66,944
257-302	125-150	33,476	17,638	903,712,084	427,604	207,170	117,846
302-347	150-175	3,979	2,338	224,940,351	138,389	72,719	45,147
347-392	175-200	653	553	13,815,637	11,267	6,425	4,412
>392	>200	40	16	1,521,414	1,854	1,180	898
Unknown Temp		762,410	95,980	3,575,205,050	-	-	-
Total		**2,475,520**	**495,697**	**15,072,137,911**	**1,297,620**	**559,889**	**276,030**

The co-produced water electricity generation potential based on the MIT model is 560 MW_e. This is significantly smaller than the range of 4,591 to 21,933 MW_e cited in the MIT *Future of Geothermal Energy* report (2006, Table A.2.2). The reasons for this are twofold. First, the MIT report used the *processed* water volumes from oil and gas reported by Curtice and Dalrymple (2004) rather than the *produced* water volumes in their estimate. Since the water is counted as processed once when it is produced from the well, and again when it is disposed of, this effectively doubled the co-produced water volume used in the MIT report estimate. Second, the MIT report assumed a single temperature for the entire volume of co-produced water and then calculated its electricity generation potential at that temperature. Various temperature scenarios ranging from 100° C (212° F) to 180° C (356° F) were assumed. Table 8 shows that this study found that the estimated temperature profile of oil and gas wells is heavily skewed towards lower temperatures that have little or no electricity generation potential.

Table 9 shows the co-produced resource potential by state, ranked in order from greatest to smallest potential. Based on the information in the database, Texas by far has

Table 9. Estimated Co-Produced Water Resource Electricity Generation Potential by State.

State	Active Wells	Co-Produced Water Volume (bbl/year)		Estimated Power Production Potential		
				Exergy	MIT Model	COTS Model
		Total	Estimated Temp >176ºF (80ºC)	(kW_e)	(kW_e)	(kW_e)
TX	63,542	2,607,232,920	2,199,237,843	778,405	352,035	185,200
OK	75,228	2,202,104,747	806,215,692	180,149	66,983	25,205
LA	10,669	1,088,845,115	594,167,708	138,274	52,617	20,773
MT	10,187	168,353,140	112,324,595	54,218	26,951	15,882
ND	4,769	153,128,630	109,159,078	44,984	21,422	12,130
WY	42,497	2,229,499,084	88,133,295	23,556	9,795	4,598
MS	3,723	314,639,592	83,720,545	22,920	9,248	4,258
CA	52,055	2,653,300,165	74,753,706	16,145	5,898	2,113
NM	49,417	699,549,055	61,123,943	10,884	3,633	850
UT	9,692	156,176,293	34,970,895	9,757	4,009	1,860
CO	35,114	334,730,672	30,564,343	6,289	2,269	758
AL	6,367	110,284,242	16,964,313	5,051	2,113	1,026
AR	4,182	141,146,855	13,559,636	3,451	1,354	586
FL	55	10,951,819	4,720,377	2,183	1,049	590
SD	222	3,938,560	3,001,771	828	334	154
NE	693	49,312,914	1,436,916	281	99	30
NV	87	7,174,590	976,752	172	57	13
OH	41,639	4,458,065	201,274	34	11	2
NY	10,277	1,124,494	131,357	21	7	1
WV	53,055	17,765,582	91,375	15	5	1
AK[1]	2,309	740,218,875	-	-	-	-
KS	4,041	1,263,934,847	-	-	-	-
KY	11,998	12,262,536	-	-	-	-
MI	3,879	102,005,119	-	-	-	-
Totals	**495,697**	**15,072,137,911**	**4,235,455,413**	**1,297,620**	**559,889**	**276,030**

[1] Wells in Alaska did not have temperature estimates due to a lack of temperature-at-depth data.

the largest electricity generation potential from co-produced water resources, accounting for 60-67% of the total co-produced resource, depending on the model that is used. Texas is followed distantly by Oklahoma, Louisiana, Montana, and North Dakota, respectively, which combined account for about 30% of the total co-produced resource potential. These results warrant a reminder that due to a lack of detailed co-produced water data in Texas, several assumptions were needed to estimate the state's resource potential. The resource estimates are based on water reinjection data, the only co-produced water data readily available from Texas, and further exclude all oil wells and any gas wells shallower than 5,000 ft (1,524 m). Water production from the remaining gas wells in the database was estimated based on the amount of gas production reported and assumes 511 bbl of water per MMcf of gas. Given the prominence of the estimate for Texas relative to the total resource estimate, more detailed data on co-produced water from wells in Texas is needed.

By contrast, most of the remaining states have relatively little potential. The states outside the top five combined only represent 6-8% of the total co-produced resource potential. Kansas, Kentucky, and Michigan have no estimated co-produced resource potential because none of the wells in those states is estimated to produce fluids above 176° F (80° C). This is especially surprising for Kansas, given that it ranks fifth in co-produced water volume with over 1.2 billion bbl per year.

Sensitivity Scenarios: The co-produced water resource potential estimate was made using as much available data as possible, but still contains data gaps and relies on several assumptions about co-produced water volumes and temperatures. To determine the impact that data gaps and errors or inconsistencies in these assumptions could have on the total co-production resource potential, several sensitivity scenarios were considered:

1. *Unknown Temperatures*: To account for the co-produced water volumes whose temperatures could not be estimated (mostly due to missing well depth data), this scenario assumes that the co-produced water with "unknown" temperatures have the same temperature distribution as the co-produced water volumes in the database with estimated temperatures.
2. *All Wells 36° F (20° C) Hotter*: The data and methods used to estimate well temperatures were based on relatively sparse data spread across large areas. To determine the impact of consistently underestimating co-produced water temperatures, it was assumed that all wells are actually 36° F (20° C) hotter than the estimated temperatures in the database.
3. *All Texas Wells 300° F (150° C)*: As discussed in the results above, Texas alone accounts for the majority of the co-produced resource potential. However, the co-produced water estimates for Texas are based on reinjection data and water-to-gas ratios rather than actual co-produced water per-well data. This scenario considers

Table 10. Estimated Co-Produced Water Power Generation Potential for Sensitivity Scenarios.

Scenario	MIT Model			COTS Model		
	Additional Generation Potential		Total Generation Potential	Additional Generation Potential		Total Generation Potential
	(kW_e)	(%)	(kW_e)	(kW_e)	(%)	(kW_e)
Base Case	-	-	*559,889*	-	-	*276,030*
Unknown Temperatures are Similar to Known	+174,109	+31%	*733,998*	+85,837	+31%	*361,867*
All Wells 36ºF (20ºC) Hotter	+412,727	+74%	972,616	+253,471	+92%	529,501
All Texas Wells 300ºF (150ºC)	+378,615	+68%	938,504	+246,450	+89%	522,480

what would be the result if all 2.6 billion bbl/year of water produced from the gas wells in Texas greater than 5,000 feet deep were 300° F (150° C). It should be noted that no Texas wells in the co-production database have estimated temperatures >392° F (>200° C).

The impacts of these sensitivity scenarios are shown in Table 10. As one would expect, the impact of including the co-produced water with unknown temperatures in the resource estimate is directly proportional to its relative volume: increasing the volume of water included in the resource estimate by 31% increases its power generation potential by the same percentage. As mentioned previously, the majority (over 85%) of co-produced water volume missing temperature estimates comes from three states (California, Alaska, and Oklahoma). Since many of the wells with missing depth data from California and Oklahoma come from fields with old, shallow oil wells that are likely not suitable for co-production, this scenario gives an optimistic estimate for the power generation potential from wells with unknown temperatures. The actual co-produced resource potential is likely somewhere between the 276 MW_e in the base case and the 362 MW_e estimated for this scenario.

Assuming all wells are 36° F (20° C) hotter has a two-fold effect. First, it brings a large number of wells that were below the 176° F (80° C) cut-off temperature into the resource estimate. Any well with an estimated temperature of 140° F (60° C) or more is included in this scenario. Second, it significantly increases the power generation potential of all wells included in the resource estimate, as Table 4 shows. The net effect is a dramatic increase in the estimated co-produced water power generation potential, nearly doubling it for the case where the COTS model is used. This shows that the estimate is sensitive to errors in resource temperature measurement.

Scenario 3, where all the wells included in the resource estimate for Texas are assumed to be 300° F (150° C), also has a large impact. Even though this scenario is not realistic, it does illustrate that even if the temperature estimates for the wells in Texas are grossly inaccurate, the total resource estimate is likely within a factor of 2 of its actual value.

A final lesson from the sensitivity scenarios is that, under any likely scenario, the co-production power generation potential is still relatively small. Even if all the scenarios in Table 10 are considered simultaneously, the co-production resource potential is still only about 2 GW_e under the COTS Model, or about the size of several large coal plants.

Conclusions

The purpose of this study was to develop an order-of-magnitude estimate of the near-term electricity generation potential of water co-produced as a by-product of oil and gas production. The estimate only considers wells that were actively producing oil and/or gas, and calculates the potential by assuming that a binary power plant is incorporated into existing oil and gas operations to take advantage of the geothermal energy from co-produced water. Table 8 summarizes the number of total wells, active wells, and co-produced water volume accounted for by the co-production database, as well as the estimated electricity generation potential from the three electricity generation models used in the study.

Based on the data gathered for this study, the following results were found:

1. The majority of active U.S. oil and gas wells are likely too low in temperature to be used for electricity generation. Well temperatures are skewed toward lower temperatures, so that the well count for a given temperature range drops rapidly as the temperature increases.
2. The maximum theoretical electricity generation potential based on the exergy of the co-produced water volumes in the database with estimated temperatures is 1.3 GW_e. Actual generation potential from practical systems will be much lower than this, but this calculation was included to give an upper bound to the estimate and to allow interested parties to apply their own assumptions regarding power plant performance to the results of this study and draw their own conclusions.
3. The electricity generation potential for resources in the co-production database based on the MIT model is 560 MW_e. When is it assumed that co-produced water volume in the database with unknown temperatures (temperature could not be estimated based on available data) has a similar temperature distribution to the rest of the database, the estimate increases to 734 MW_e. This is significantly smaller than the range of 4.6 to 21.9 GW_e cited in the MIT *Future of Geothermal Energy* report (MIT 2006, Table A.2.2). The reasons for this discrepancy are that the MIT report double-counted the co-produced water volume in their estimate and also applied uniform temperature estimates for the co-produced water volume to demonstrate their potential. This study found that the actual temperature distribution of oil and gas wells includes a large number of wells with temperatures below any scenario considered in the MIT study.
4. The near-term co-produced water resource potential estimated by the COTS model is 276 MW_e based on the information available in the co-production database, and increases to 362 MW_e when an assumed temperature profile for wells with unknown temperatures is included. This model gives the most realistic estimate of the co-production resource potential.
5. The resource estimate is particularly sensitive to the estimated temperature of the co-produced water. It was found that if all wells were actually 36° F (20° C) hotter than estimated in this study, the resource potential using the COTS model would nearly double. This indicates that additional study and data on the actual wellhead fluid temperatures is needed to determine a more accurate estimate of the co-production resource potential.
6. The majority of the co-produced resource potential is in Texas, which accounts for 67% of the electricity generation potential under the COTS model. The co-produced water data from Texas is based on reported re-injected water volume, and several assumptions were used to arrive at the resource potential estimate. Only gas wells with depths >5,000 ft (>1,524m) were considered in the estimate, and

the co-produced water volumes for these wells were estimated based on the amount of gas production reported for each well and assuming an gas-to-water ratio of 511 bbl of water per MMcf gas. Given the prominence of Texas in the estimate, a more thorough study of its co-production resource based on per-well temperature and co-produced water volume data is needed. However, even if it assumed that all the co-produced water ascribed to the gas wells in this estimate are 300° F (150° C), the resource potential is still only 522 MW_e, or about a factor of two larger.

The data used to arrive at these estimates contains data gaps and rely on assumptions about co-produced water volumes and temperatures to arrive at these conclusions. A more accurate estimate could be performed if more detailed well data were available. To improve on the resource estimate, data on co-produced water volumes from oil and gas wells is needed on a per-well basis from all state databases. Additionally, wellhead temperatures or, at a minimum, bottom hole well temperatures on a per-well basis would greatly improve the accuracy of the estimate. As mentioned above, this data is especially needed from wells in the state of Texas. Future efforts should also focus on gathering data for wells in California, Alaska, and Oklahoma, which account for 85% of the co-produced water volumes that lack temperature estimates in the co-production database.

In conclusion, the study indicates that there are a significant number of oil and gas operations with sufficient temperatures and co-produced water volumes that could potentially be utilized for co-production electricity generation. These sites represent opportunities where binary power plants could be installed to produce electricity with little disruption to existing oil and gas operations. However, the study found that there is less resource than prior publications suggest. The near-term market potential for the co-produced water resource is roughly 300 MW_e. These estimates only represent the resource potential and do not take into account practical operational factors such as a minimum power plant size, availability of cooling water or transmission, project economics, etc. Conversely, the resource estimate only addresses active oil and gas wells. The total number of wells (including inactive wells) that could potentially be re-engineered to produce electricity is several times larger. This study did not attempt to estimate the power generation potential under this scenario.

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Nomenclature

η_{th} = thermal efficiency, %

= exergy, kJ/s

$H(T)$ = specific enthalpy of fluid at temperature T, kJ/kg

$\dot{m}$ = mass flow rate of co-production resource (water from well), kg/s

$\dot{Q}$ = rate of net heat input to power plant, kW_{th}

$S(T)$ = specific entropy of fluid at temperature T, kJ/(kg-°C)

$T_{ambient}$ = ambient temperature, °C

T_{in} = plant inlet temperature, °C

T_{out} = plant outlet temperature, °C

W = net power output from power plant, kW_e

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[1] The authors would like to emphasize that the use of typical performance characteristics for the Pratt & Whitney Model 280 PureCycle® system do not constitute an endorsement of either that particular system or the company that manufactures it. The performance data for this system was used to represent a commercially available binary system simply because it was readily available from data in promotional brochures.

Appendix A: State Oil and Gas Well Data Sources

AK – Alaska

Alaska Oil and Gas Commission, "Download Oil and Gas Data, 2009." Available at http://doa.alaska.gov/ogc/publicdb.html. Accessed March 30, 2010.

AL – Alabama

Hall. J. 2010, personal communication between J. Hall, Alabama Oil and Gas Board, Tuscaloosa, AL, and D. Falkentern National Renewable Energy Lab, Golden, CO, March 30.

Hall. J. 2010, "Oil and Gas Well Information 2009." Alabama Oil and Gas Board, April 20.

AZ – Arizona

Arizona Oil and Gas Conservation Commission, "Download Annual Production." Available at http://www.azogcc.az.gov/index.php?option=com_content&view=article&id=50&Itemid=56. Accessed March 30, 2010.

AR – Arkansas

Arkansas GeoStor: Arkansas' Official GIS Platform, "Download Oil Gas Well (point)." Available at http://www.geostor.arkansas.gov/G6/Home.html. Accessed April 13, 2010.

Arkansas Oil and Gas Commission, "Download Arkansas Oil and Natural Gas Well Map." Available at http://www.aogc.state.ar.us/Maps_GoogleEarth.htm. Accessed July 26, 2010.

CA – California

California Department of Conservation, Division of Oil, Gas and Geothermal Resources, "Download production_database from new_data_format and CA_Wells from Data_Catalog, 2009." Available at ftp://ftp.consrv.ca.gov/pub/oil/. Accessed March 16, 2010.

Cummings. M. 2010, personal communication between M. Cummings, California Department of Conservation, District 6, Oil, Sacramento, CA, and D. Falkentern National Renewable Energy Lab, Golden, CO, June 23.

Cummings, M., "CA District 6 Well Depths." June 23, 2010.

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Fields, S., "CA District 2 Well Depths." June 25, 2010.

Glinzak, M. 2010, personal communication between M. Glinzak, California Department of Conservation, District 4, Oil, Bakersfield, CA, and D. Falkentern National Renewable Energy Lab, Golden, CO, July 7.

Glinzak, M., "CA District 4 Well Depths." July 7, 2010.

CO – Colorado

Colorado Oil and Gas Commission Department "Download Well Shape File, 2008." Available at http://cogcc.state.co.us/. Accessed March 23, 2010.

Morgan, P. 2010, personal communication between P. Morgan, Colorado Geological Survey, Denver, CO, and D. Falkentern National Renewable Energy Lab, Golden, CO, July 2.

Morgan, P., "Colorado Well Depths." July 2, 2010.

FL – Florida

Florida Geological Survey, "Download Oil and Gas Index Map, Oil and Gas Production Reports, 2010." Available at http://www.dep.state.fl.us/water/mines/oil_gas/data.htm. Accessed April 21, 2010.

IL – Illinois

Illinois State Geological Survey, Available at http://www.isgs.illinois.edu/sections/gru/wellmaps.shtml. Accessed March 25, 2010.

Illinois State Geological Survey, "Download IGS Wells and Boring Points." Available at http://www.isgs.illinois.edu/nsdi-home/. Accessed March 25, 2010.

Illinois State Geological Survey, "ILOIL Interactive Mapping Web Interface." Available at http://www.isgs.illinois.edu/sections/oil-gas/launchims.shtml. Accessed March 25, 2010.

IN – Indiana

Indiana Geological Survey, "Petroleum Database Management System." Available at http://igs.indiana.edu/pdms/index.cfm. Accessed March 31, 2010.

KS – Kansas

Kansas Geological Survey, "Download Master list of oil and gas wells, 2009." Available at http://www.kgs.ku.edu/PRS/petroDB.html. Accessed March 25, 2010.

Kansas Oil and Gas Commission, "Download Oil and Gas Production Volumes, 2009." Available at http://www.kcc.state.ks.us/conservation/production/index.htm. Accessed March 25, 2010.

KY – Kentucky

Nuttall, B. 2010, personal communication between B. Nuttall, Kentucky Geological Survey, Lexington, KY, and D. Falkentern National Renewable Energy Lab, Golden, CO, April 9.

Nuttall, B.,"FTP delivery of Kentucky oil and gas well information and production." April 9, 2010.

LA – Louisiana

Caston, T. 2010, personal communication between T. Caston, Louisiana Department of Natural Resources, Baton Rouge, LA, and D. Falkentern National Renewable Energy Lab, Golden, CO, April 13.

Caston, T.,"FTP delivery of Louisiana oil and gas well information and production." April 13, 2010.

MI – Michigan

Michigan Department of Natural Resources and Environment, "Download Online Oil and Gas Database, 2009." Available at http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231-188295--,00.html. Accessed March 17, 2010.

MS – Mississippi

Thompson, D. 2010, personal communication between D. Thompson, Mississippi Oil and Gas Board Jackson, MS, and D. Falkentern National Renewable Energy Lab, Golden, CO, April 28.

MS – Mississippi (cont'd.)

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MT – Montana

Montana Department of Natural Resources and Environment, "Download Oil Wells and Production from Data Miner V2, 2008." Available at http://bogc.dnrc.state.mt.us/onlinedata.asp. Accessed March 25, 2010.

ND – North Dakota

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NE – Nebraska

Nebraska Conservation Commission, "Download Well Data, 2008." Available at http://www.nogcc.ne.gov/NOGCCPublications.aspx. Accessed March 25, 2010.

NV – Nevada

Nevada Bureau of Mines and Geology, "Download Well Listed by API and Production Data, 2008." Available at http://www.nogcc.ne.gov/NOGCCPublications.aspx. Accessed July 27, 2010.

NM – New Mexico

New Mexico Tech, "Download Complete Table, 2009." Available at http://octane.nmt.edu/gotech/Petroleum_Data/allwells.aspx. Accessed April 28, 2010.

NY – New York

New York Department of Environmental Conservation, "Download wellDOS.zip, 2008." Available at http://www.dec.ny.gov/energy/30438.html. Accessed April 28, 2010.

OH – Ohio

Ohio Department of Natural Resources, Division of Mineral Resources Management, "Download Oil and Gas Well Database, 2007." Available at http://www.dnr.state.oh.us/mineral/database/tabid/17730/Default.aspx. Accessed April 1, 2010.

OK – Oklahoma

Oklahoma Corporation Commission, Oil and Gas Conservation Division, "Download Intent to Drill, Well Construction, Basic Well Information, 2008." Available at http://www.occ.state.ok.us/divisions/og/newweb/ogdatafiles.htm. Accessed April 16, 2010.

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OR – Oregon

Oregon Department of Geology and Mineral Industries, "Download Oil & Gas Well Permits/Locations, 2010." Available at http://www.oregongeology.org/sub/oil/oilhome.htm. Accessed March 31, 2010.

PA – Pennsylvania

Pennsylvania Department Natural Resources and Conservation, Geological Survey, Available at http://www.dcnr.state.pa.us/topogeo/oilandgas/pairisinfo.aspx. Accessed March 31, 2010.

SD – South Dakota

South Dakota Department of Environmental and Natural Resources, "Download Well Data and Injection/Production, 2009." Available at http://denr.sd.gov/des/og/welldata.aspx. Accessed April 16, 2010.

TN – Tennessee

Tennessee Department of Environment and Conservation, Division of Geology, Available at http://www.state.tn.us/environment/tdg/mineralind.shtml. Accessed March 31, 2010.

TX – Texas

Kay, M.L. 2010, personal communication between M.L. Kay, MLKay Technologies, Bellaire, TX, and D. Falkenstern National Renewable Energy Lab, Golden, CO, April 22.

MLKay Technologies, "FTP delivery of Well Information Databases," May 10, 2010.

MLKay Technologies, "FTP delivery of Well Production Databases," August 11, 2010.

UT – Utah

State of Utah Oil and Gas Program, "Download Well Data and Production Data, 2009." Available at http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm. Accessed March 22, 2010.

VA – Virginia

Virginia Department of Mines Minerals and Energy, "Download Well Location and Production, 2009." Available at http://www.dmme.virginia.gov/dgoinquiry/frmmain.aspx. Accessed March 31, 2010.

WA – Washington

Washington State Department of Natural Resources, Available at http://www.dnr.wa.gov/ResearchScience/Topics/EarthResources/Pages/oil_gas_resources.aspx. Accessed April 1, 2010.

WV – West Virginia

West Virginia Department of Geologic and Economic Survey "Purchased Oil and Gas Well Data DVD, 2009." Available at http://www.wvgs.wvnet.edu/www/datastat/datastat.htm#DVD. Accessed March 28, 2010.

WY – Wyoming

Wyoming Oil and Gas Commission "Download Wells and Production, 2007." Available at http://wogcc.state.wy.us/. Accessed March 23, 2010.