THE WATER-ELECTRICITY NEXUS IN CALIFORNIA: DROUGHT-INDUCED RISK TO THERMAL ELECTRICITY GENERATION

By

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ABSTRACT

THE WATER-ELECTRICITY NEXUS IN CALIFORNIA: DROUGHT-INDUCED RISK TO THERMAL ELECTRICITY GENERATION

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Investigating the possibility that drought might limit the water supply needed for thermal electricity generation in California, power plant water consumption data was compared to urban and agricultural consumptive demands to identify where power plants might contribute to regional water stress. Similarly, to identify where power plants might be impacted by water stress, power plant, urban, and agricultural water demands were compared to the region's available water supply. A list of power plants that would contribute most to regional water scarcity (individually and in aggregate) was highlighted, based on the plant's water consumption volume, water-intensity, and water source. A list of at-risk power plants, located in high water stress regions, was highlighted, based on the water source consumed by the plant. Recommendations were offered for avoiding water stress-related issues at power plants contributing most to regional water stress, or located in regions of high water stress. Various data quality issues related to power plant water use were also highlighted, and recommendations proposed for mitigating those issues.

Numerous studies have looked into the water-intensity of electricity generation in California, but a lack of available data from the state's power plants have limited these

studies to using literature estimates from previous studies, or to forming estimates based off of "representative" power plants. This study is believed to be the first to calculate the water-intensity of California's electricity generation infrastructure at the individual power plant scale using water use and electricity generation data reported to the California Energy Commission.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

INTRODUCTION

The Water-Energy Nexus

The term “water-energy nexus” refers to the intimate relationship between water and energy supplies (Figure 1 and Figure 2). With regard to energy systems, water is used for resource extraction, the refining, processing, and transportation of fuel, hydroelectric generation, thermal power plant cooling, and emissions scrubbing (Pate, 2007). With regard to water services, energy is needed for transferring water from one location to another, groundwater pumping, desalination, heating and cooling, and water treatment (Gleick, 1994; Klein, 2005).

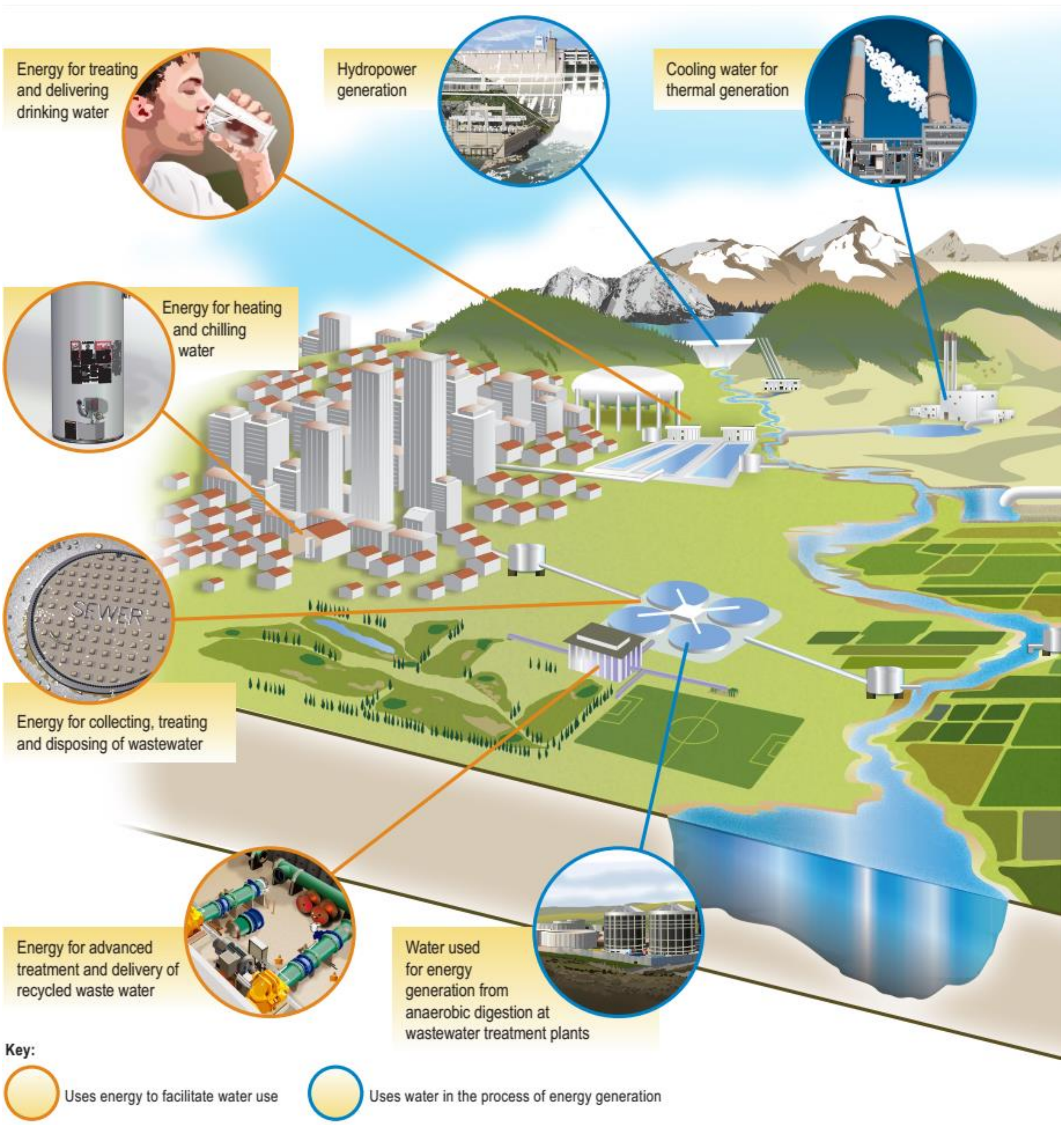

Figure 1. A visual representation of the water-energy nexus (California Department of Water Resources, 2016).

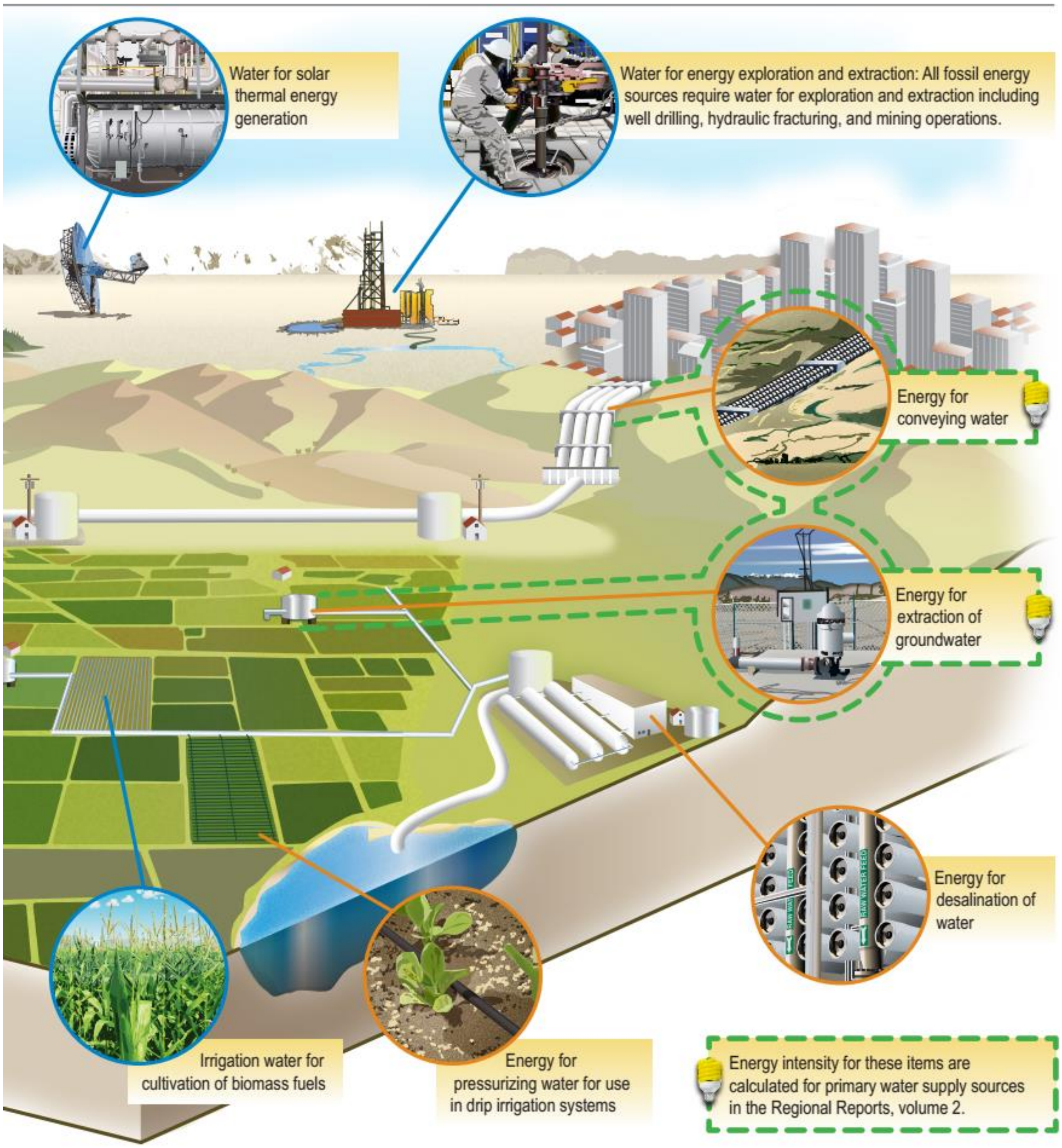

Figure 2. A visual representation of the water-energy nexus (California Department of Water Resources, 2016). This is the second half of Figure 1.

There are two overarching elements of the water-energy nexus. The first compares the amount of energy needed to supply a unit of water, referred to as the energy-intensity of water. Multiple California studies have already focused on the energy-intensity of the water supply (Cohen, 2004; Klein, 2005; Navigant Consulting, 2006; House, 2007; Wolff, 2011; GEI Consultants, 2012; The Climate Registry, 2013; California Department of Water Resources [CDWR], 2013a).

The second compares the amount of water needed to generate a unit of energy, referred to as the water-intensity of energy. A number of studies have looked at the water-intensity of electricity generation in California (California Energy Commission [CEC], 2001; Maulbetsch, 2002; CEC, 2003; CEC, 2005; Larson, 2007; CEC, 2008; Fulton, 2015; CEC, 2015b), but these have been limited to using literature estimates from previous studies, or to forming estimates based off of representative power plants, due to the lack of available water use data for the state's power plants.

A History of Drought in California

California has a long paleoclimate record of re-occurring multi-year droughts dating back to at least 900 AD (Jones, 2015). Drought is caused by a shortage of water, yet there is neither a universal method of measuring, nor a universal definition of when a drought formally begins or ends (Jones, 2015). Likewise, California does not have a legal definition or process for defining or declaring drought (Jones, 2015). Drought can be measured in multiple ways. Examples include meteorological drought (a period of below average precipitation), hydrological drought (a period of below average runoff), or agricultural drought (a period of below average soil moisture (Jones, 2015; California Water Science Center, 2017a). Some of California's most recent, and severe, statewide multi-year droughts occurred during the years 1929-1934, 1976-1977, 1987-1992, 2007-2009, and 2012-2015 (Figure 3). In Figure 3, most drought years occurred when annual runoff depths were roughly six inches or less. The average runoff between 1901-2015 was 9.35 inches, and the median runoff was 8.49 inches.

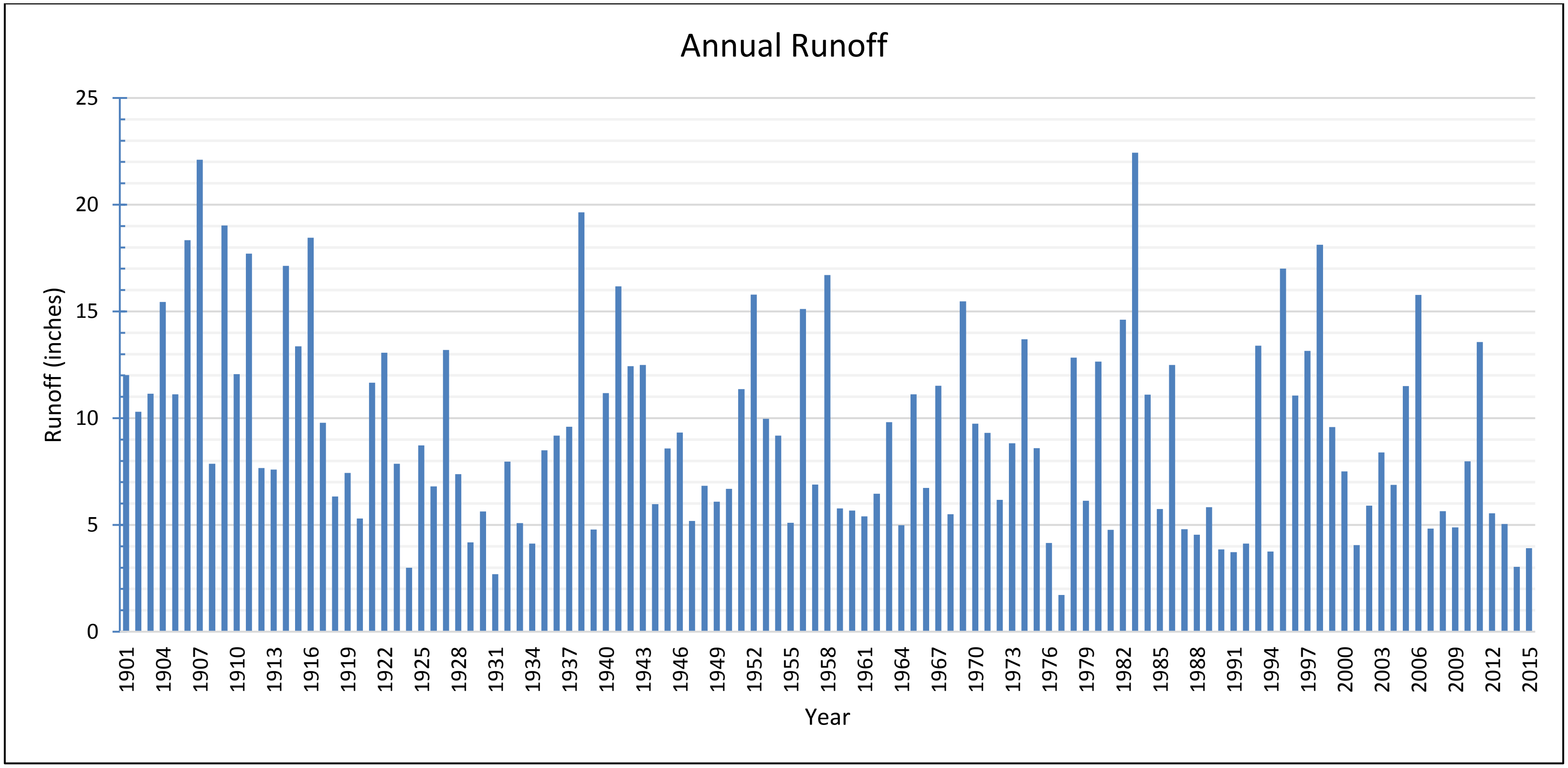

Figure 3. California's estimated annual statewide runoff from 1901-2015 (California Water Science Center, 2017b). Most drought years occur when annual runoff depths are roughly six inches or less.

Drought Impacts on California's Electricity Generation

Past and current droughts have significantly reduced the amount of hydroelectric generation in California, while causing an accompanying increase in all of the following: in-state natural gas generation, economic cost of electricity generation, greenhouse gas emissions, and out of state electricity imports (Gleick, 1991; Christian-Smith, 2011; Gleick, 2015; Gleick, 2016; Gleick, 2017). In general, hydroelectric and natural gas generation have tended to mirror one another, so that when hydroelectric generation decreases, natural gas generation increases, and vice versa (Figure 4).

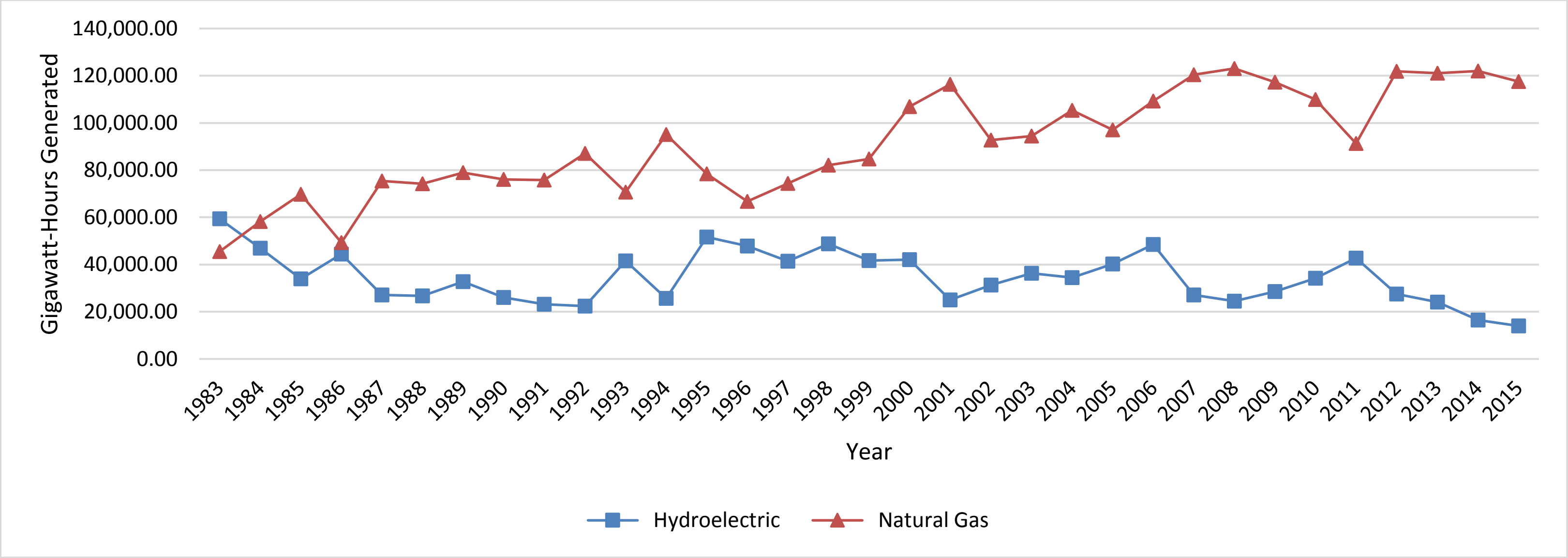

Figure 4. Hydroelectric versus natural gas generation between the years 1983-2015 (CEC, 2016b).

During the 1987-1990 drought years, the resulting increase in in-state natural gas generation cost California ratepayers an estimated extra $2.4 billion, leading to a 25 percent increase in carbon dioxide emissions from California's in-state power plants, relative to a normal water year (Gleick, 1991). During the 2007-2009 drought years, the extra in-state natural gas generation cost California ratepayers an estimated additional $1.7 billion, leading to a 10 percent increase in carbon dioxide emissions from California's in-state power plants (Christian-Smith, 2011). During the 2012-2016 drought years, increased in-state natural gas generation cost ratepayers an extra estimated $2.45 billion, again leading to a 10 percent increase in carbon dioxide emissions from California's in-state power plants (Gleick, 2017).

From the year 2012 until the latter part of 2016, California was in a continuous state of drought, with the last non-drought year occurring in 2011 (National Integrated Drought Information System, 2017; Gleick, 2017). In 2011, hydroelectric generation made up nearly 15 percent of California's electricity. Afterwards, hydroelectric generation steadily declined, only generating around 5 percent by 2015 (Table 1). Over the same time period, natural gas increased from about 31 percent of generation, in 2011, to about 40 percent for years 2012-2015 (Table 1).

Table 1. Annual electricity generation by fuel source (as a percentage of total generation) during the most recent drought (CEC, 2016b).

Fuel Source	**2011**	**2012**	**2013**	**2014**	**2015**
Hydroelectric	14.55	9.08	8.13	5.55	4.74
Nuclear	12.48	6.12	6.03	5.73	6.27
Coal	1.06	0.52	0.34	0.34	0.18
Oil	0.01	0.02	0.01	0.02	0.02
Natural Gas	31.05	40.31	40.86	41.07	39.77
Geothermal	4.32	4.21	4.21	4.10	4.06
Biomass	2.06	2.05	2.21	2.28	2.15
Wind	2.59	3.06	4.04	4.40	4.12
Solar PV	0.07	0.32	1.23	3.02	4.27
Solar Thermal	0.30	0.29	0.23	0.55	0.83
Other	0.00	0.00	0.00	0.01	0.00
Net Northwest Imports	11.99	13.06	11.84	12.54	12.12
Net Southwest Imports	19.52	20.96	20.85	20.40	21.47
Total Generation Plus Net Imports (GWh)	**293,779.25**	**302,319.70**	**296,249.68**	**297,061.51**	**295,404.76**

The current drought coincided with the closure of the San Onofre nuclear plant, which explains the drop in nuclear generation after 2011. Solar PV, wind, and imports, have had secondary roles in replacing the lost hydroelectric and nuclear generation (Table 1).

Thesis Goals

This study focuses on a subset of the water-intensity of energy, specifically the water-intensity of California’s electricity generation infrastructure. Given California’s long history of drought (Jones, 2015), and the negative impact of drought on the water supply and on hydroelectric generation (Gleick, 1991; Christian-Smith, 2011; Gleick, 2015; Gleick, 2016; Gleick, 2017), the author was concerned that drought-induced water shortage could also place California’s non-hydroelectric power plants at risk. To investigate this possibility, water use and electricity generation data, as reported to the California Energy Commission (CEC), was examined in the context of regional water scarcity to identify areas where power plants might contribute to, or might be impacted by water stress.

After reviewing the available literature, it appears that California has not completed studies that calculate and characterize the water-intensity of California's electricity infrastructure, at the scale of individual power plants, by using reported water use and electricity generation data. This study fills that gap.

The goals of this study were to:

1. Analyze the water used by California’s power plants for electricity generation, and calculate the weighted average water-intensity (on a gallons of water consumed per megawatt-hour [MWh] of electricity generated basis) at the individual power plant scale, subcategorized by generation technology, fuel type, and cooling system where possible.
2. Identify regions (California Department of Water Resources [CDWR] defined planning areas) where power plants may be contributing to water stress by comparing average power plant water consumption to the average human consumptive demands (from power plants, agriculture, and urban sectors).

3. Identify power plants located in regions (i.e. planning areas) already experiencing high water stress by comparing average human consumptive demands to the average available water supply.

BACKGROUND: FACTORS DETERMINING THE WATER REQUIREMENTS OF A POWER PLANT

Water Withdrawal Versus Water Consumption

Before moving on, it is important to understand the distinction between the terms "water use", "water withdrawals", and "water consumption". The term water use refers to both withdrawals and consumption without distinction. The United States Government Accountability Office (GAO) (2009) makes a distinction between withdrawals versus consumption:

> "Water withdrawals refers to water removed from the ground or diverted from a surface water source—for example, an ocean, river, or lake—for use. Water consumption refers to the portion of the water withdrawn that is no longer available to be returned to a water source, such as when it has evaporated."

Water that becomes polluted beyond regulatory standards would also be considered "consumed." Water not consumed by power plants can often be discharged back to the environment, but at a significantly higher temperature (GAO, 2009). High temperature discharge water can have negative environmental impacts on aquatic ecosystems, but is otherwise available for reuse (Pate, 2007).

The Generation Technology

The generation technology (sometimes referred to as prime mover [Sanders, 2015; CEC, 2016f]) is one of the main factors determining water use at a power plant.

Power plants can have multiple generator/turbine units, some of which use thermal processes (also referred to as thermoelectric), and some of which use non-thermal processes (CEC, 2016f).

The process used for electricity generation by thermal power plants has been described in various places (GAO, 2009; GAO, 2015; Badr, 2012; Averyt, 2011; Shuster, 2011) and is summarized here. Thermal power plants require the use of fuel to drive a steam cycle, as part of the electricity generation process (Figure 5). In the steam cycle, the heat from the fuel source evaporates water inside of a boiler. The evaporated steam turns a turbine, which spins a generator, thus generating electricity. The steam is then re-condensed inside of a condenser, which allows the boiler water to be reused, and the entire process repeated. The required condensation of steam is most commonly achieved through the use of cooling water. This use of cooling water is by far the dominant water use in thermal power plants (Maulbetsch, 2008). Boiler water and cooling water are two separate water sources that do not mix (GAO, 2009; Badr, 2012; Averyt, 2011). Examples of thermal power plants include steam, and combined cycle plants fueled by coal, natural gas, oil, nuclear, biomass, solar thermal, and geothermal energy.

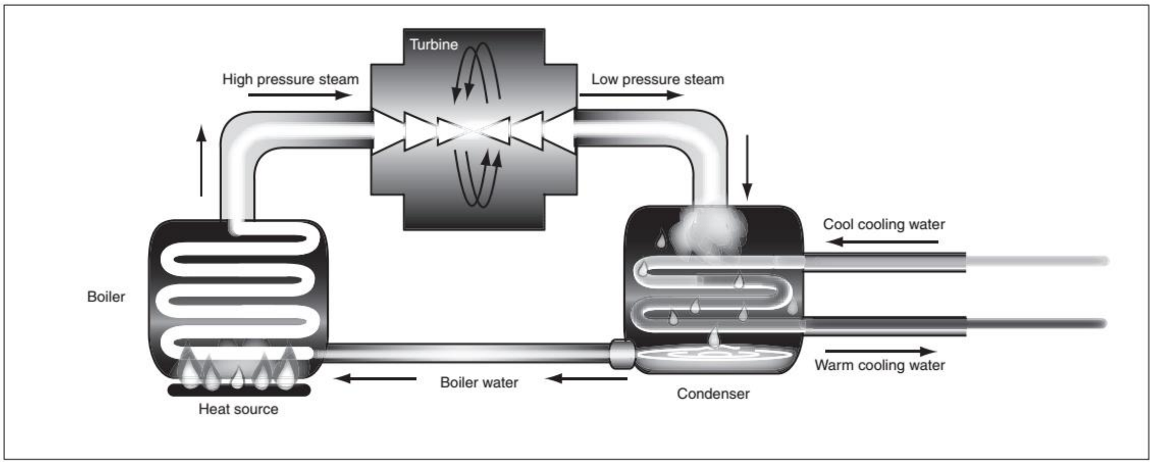

Figure 5. The steam cycle of a thermal power plant (GAO, 2009).

Non-thermal power plants, in contrast, do not have a steam cycle, and generate electricity by other means, without the need for cooling water (GAO, 2015). Examples of non-thermal power plants include wind, solar photovoltaic (PV), wave, hydroelectric, combustion gas (simple cycle) fossil fuel plants, and internal combustion engines. Some natural gas plants generate electricity with a simple combustion cycle, using the heated gas to directly spin the turbine without the need for water/steam (Maulbetsch, 2002; Maulbetsch, 2008; GAO, 2009; GAO, 2015).

To complicate matters somewhat, combined cycle power plants use both a combustion gas cycle (non-thermal process) and a steam cycle (thermal process) to generate electricity. Only the steam cycle portion of a combined cycle plant requires water. In combined cycle plants, about one-half to two-thirds of the plant's generation comes from the combustion gas turbines, and the remaining one-third to one-half from the steam turbine (Maulbetsch, 2008; Diehl, 2013). According to Poch (2009), some combined cycle plants can operate the combustion gas cycle and steam cycle separately or jointly, depending on plant needs.

In 2011, at least 67 percent of United States electricity generation came from thermal power plants, 26 percent from non-thermal plants, and the last 7 percent was not specified (United States Energy Information Administration [EIA], 2014).

The Cooling Systems Used in Thermal Power Plants

If a power plant uses thermal processes to generate electricity, then the main factor determining water use is the cooling system used to re-condense the steam from the boiler (United States Department of Energy [DOE], 2014). Thermal power plants often require significant amounts of cooling water. The four main cooling systems used in thermal power plants are: once-through cooling (or open loop), wet-recirculating (or closed loop), air-cooling (or dry-cooling), and hybrid systems. Hybrid systems combine elements of wet-recirculating and air-cooled systems, and can operate either system separately or in unison as conditions require (Maulbetsch, 2002; Maulbetsch, 2008; GAO, 2009; GAO, 2015). Classifying a power plant by cooling system is not always straightforward because a different cooling technology can be used on each generator of the power plant.

Once-through cooling systems

Once-through cooling systems withdraw large amounts of water from a water body for steam condensation purposes (GAO, 2009). After a single cycle through the power plant, the cooling water is discharged back to the environment (Figure 6), at a higher temperature than it was originally, consuming only a small fraction of the initial water withdrawn (GAO, 2009; Macknick, 2012a; Meldrum, 2013).

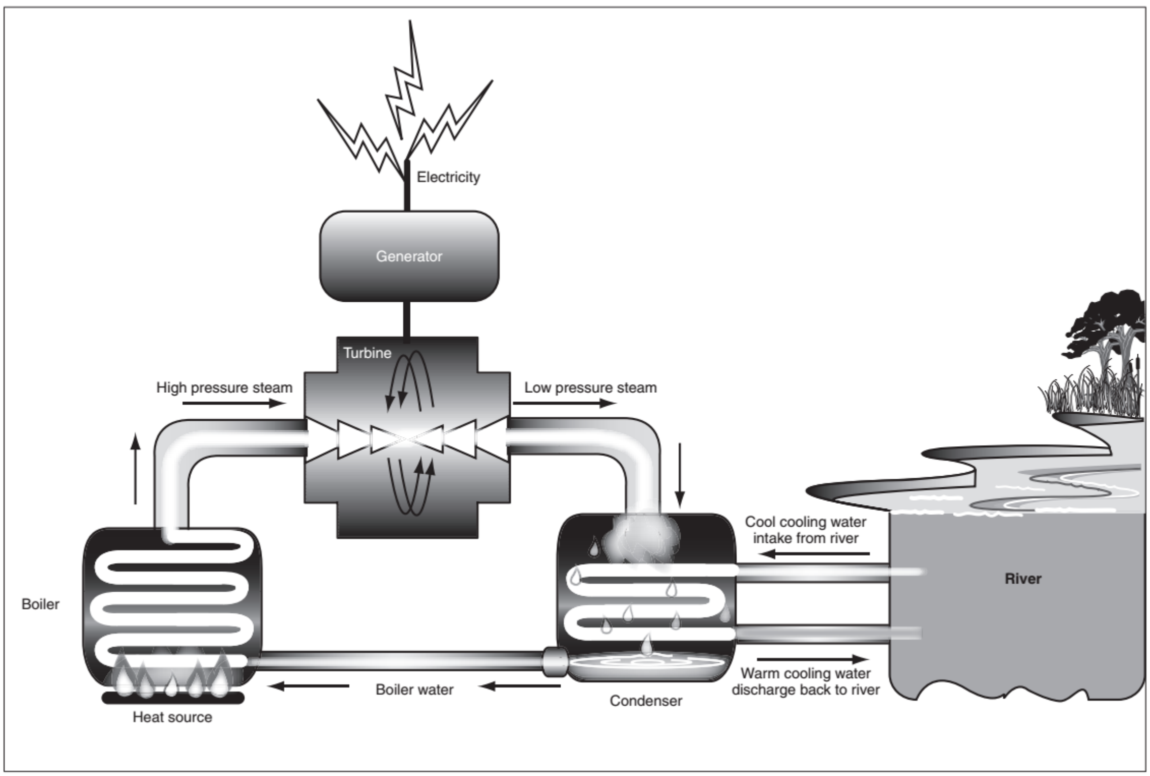

Figure 6. A once-through cooling system (GAO, 2009).

A shift away from once-through cooling. Since the 1970s, there has been a national trend moving away from once-through cooling systems in favor of wet-recirculating systems, mainly for environmental reasons (Pate, 2007; Dorjets, 2014). First, the high temperature discharge water of once-through cooling systems can cause water quality issues, potentially resulting in fish kills (Averyt, 2011; Rogers, 2013), and harming other aquatic organisms (GAO, 2009). Second, water intake structures also trap or draw in fish, and other aquatic life, at the intake point (GAO, 2009). Third, in arid regions, the high water demand of once-through cooling systems has led to the shift out of necessity (Pate, 2007).

California has followed the national trend as evidenced by a State Water Resources Control Board (2010) policy titled "Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" (alternatively referred to as the "Once-Through Cooling Water Policy"). To meet the federal Clean Water Act standards of reducing harm to aquatic life at intake structures, this policy requires 19 once-through cooled plants, using coastal or estuarine waters, to retrofit or retire all of their once-through cooled generators by the year 2030 (CEC, 2016a). Many of these power plants will be retired (some already have), while at least a few will upgrade their generators to air-cooled systems (CEC 2016a).

<u>Wet-recirculating cooling systems</u>

Wet-recirculating cooling systems withdraw orders of magnitude less water than once-through cooling systems, but consume a significantly higher fraction of the water withdrawn (GAO, 2009; Macknick, 2012a; Meldrum, 2013). Wet-recirculating systems recycle the cooling water multiple times, employing cooling towers or open ponds, to release the excess heat absorbed by the cooling water as it re-condenses steam (Figure 7). In this cooling system, the cooling water can be reused over and over until the quality is degraded (due to concentration of minerals or contaminants) to the point that it must be discharged and replaced (GAO, 2009). Makeup water withdrawals are only needed to replace evaporated cooling water, and to flush away minerals and sediment that accumulate in the recirculated cooling water (Brown, 2013).

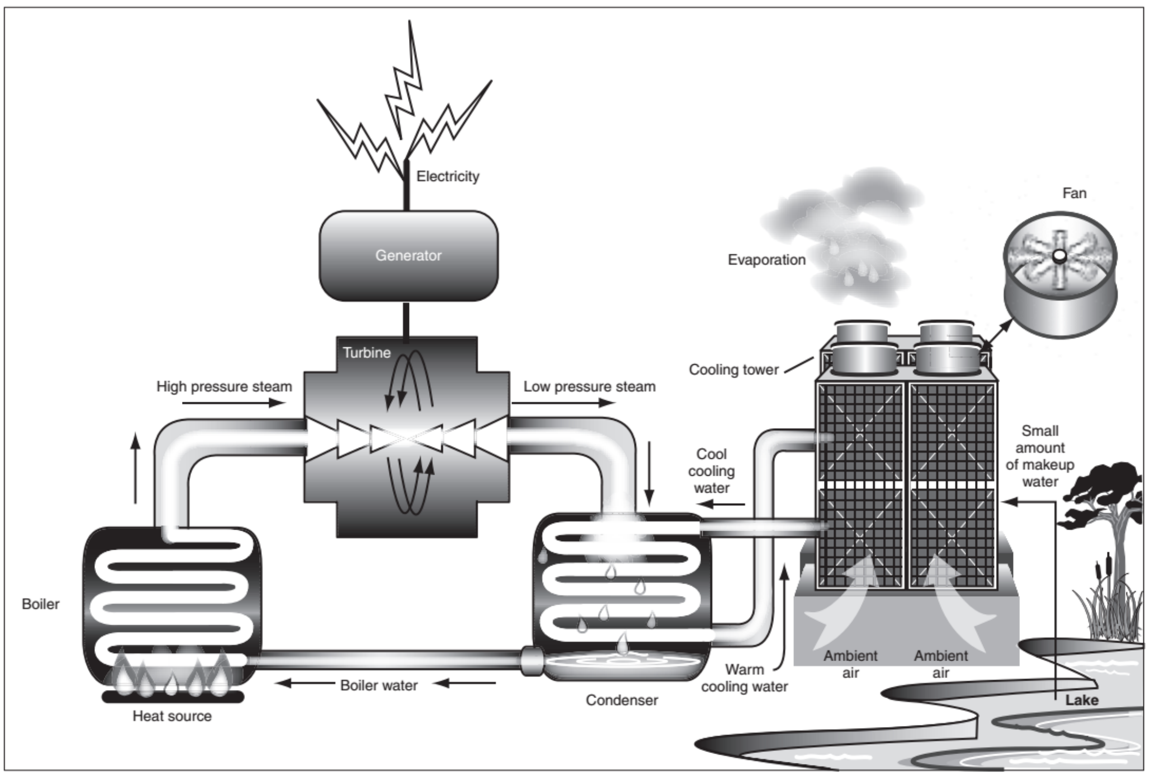

Figure 7. A wet-recirculating cooling system with a cooling tower (GAO, 2009).

Air-cooled systems

Unlike once-through and wet-recirculating cooling systems, air-cooled systems rely primarily on air, and do not require any water for cooling (GAO, 2009). Fans blow air into the power plant to condense the steam from the boiler (Figure 8).

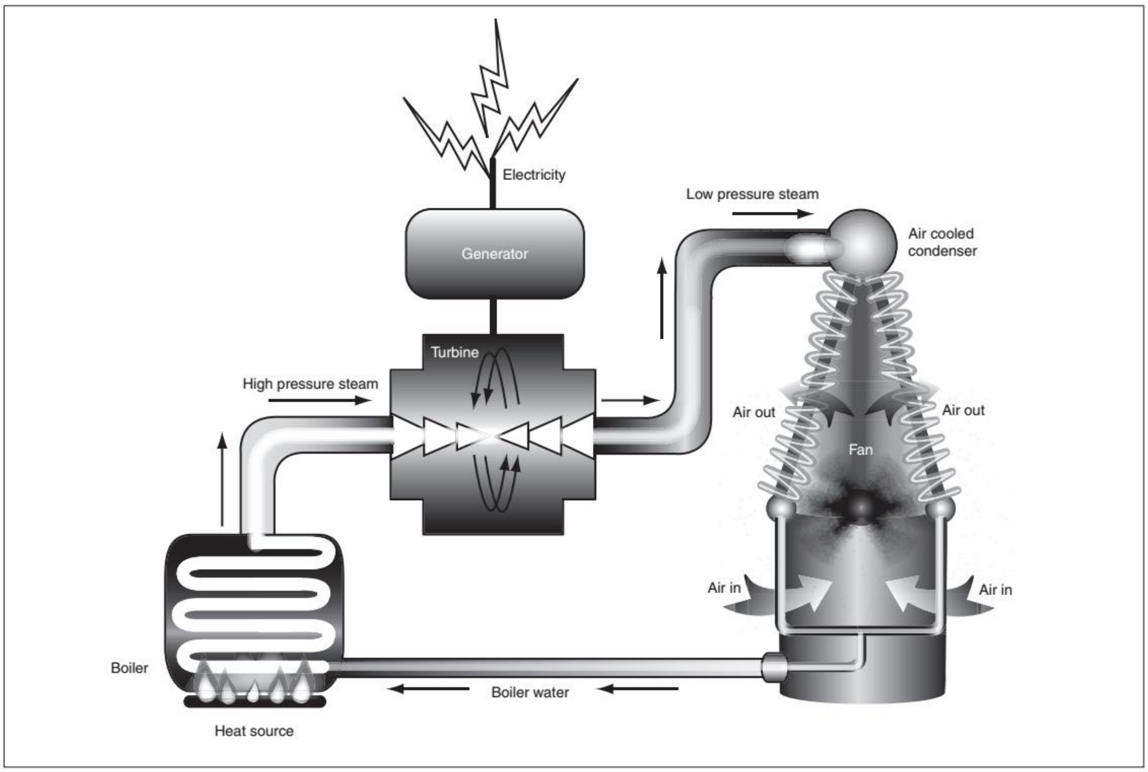

Figure 8. An air-cooled system (GAO, 2009).

General cooling system trends

Generally, air-cooled systems withdraw the least amount of water per unit of electricity generated, while once-through cooled systems withdraw the most (GAO, 2009; Macknick, 2012a; Meldrum, 2013). Air-cooled systems also consume the least amount of water per unit of electricity generated, while wet-recirculating systems consume the most (GAO, 2009; Macknick, 2012a; Meldrum, 2013).

According to the DOE (2014), in 2011, once-through cooled plants withdrew 64 percent of all United States power plant water withdrawals, while wet-recirculating plants withdrew only 17 percent of withdrawals. In contrast, wet-recirculating plants consumed about 88 percent of all power plant water consumption, while once-through cooled plants consumed only four percent (DOE, 2014). The EIA also analyzed the number of operating cooling systems installed in the United States, finding that 43.4 percent were once-through cooled, 52.9 percent wet-recirculating, 3.4 percent air-cooled, and 0.3 percent hybrid (Dorjets, 2014).

<u>Why are air-cooled systems not used more often?</u> Since air-cooled systems do not require water for cooling, it is logical to ask why these cooling systems have not become more common. When compared to once-through or wet-recirculating systems, air-cooled systems have higher capital costs, and a lower electricity generation efficiency, often making them less attractive alternatives (GAO, 2009). They are less efficient at electricity generation due to the extra onsite energy needed to run the cooling system's fans, which translates to less electricity being transmitted to the grid. Air-cooled systems also operate less efficiently in hot weather than either once-through or wet-recirculating systems. According to the GAO (2009), "the effectiveness of a cooling system decreases as the temperature of the cooling medium increases, since a warmer medium can absorb less heat from the steam." Once-through and wet-recirculating systems transfer the heat

directly to the cooling water, but air-cooled systems can only transfer the heat to ambient air, without the aid of evaporated water (GAO, 2009). In addition, the relatively lower efficiency of air-cooled systems requires more fuel, per unit of electricity generated, causing an increase in both greenhouse gas emissions (in fossil fuel powered plants) and fuel costs (GAO, 2009).

Other Factors Affecting Water Use

Besides generation technology and cooling system, the efficiency of the fuel at producing heat (and therefore electricity) also plays an important role in determining water use (Sanders, 2015). Other factors include the local climate, environmental/emissions control measures, regulations, age of the power plant and equipment, and the quality of the cooling water source (Maulbetsch, 2008; Sanders, 2015; CEC, 2015b).

In California, many power plants utilize cogeneration approaches, meaning that they produce steam for other onsite needs, or sell steam to nearby facilities, by utilizing the waste heat from electricity generation. This may increase the apparent water use of the power plant (Dennis, Christopher, personal communication, 2016).

It is also important to understand that even though non-thermal power plants, and air-cooled thermal plants, do not require cooling water for condensing steam inside of a boiler, water use may not be entirely eliminated. All power plants potentially require water for equipment washing, employee restrooms, emissions control, and occasional replacement of boiler water (in the case of thermal power plants) (DOE, 2006; Maulbetsch, 2008). Many combustion gas (simple cycle), and combined cycle power plants also use technologies called inlet air cooling and/or intercooling (both of which use water) to cool the heated gas before it enters the combustion turbine (Maulbetsch, 2008; Sanders, 2015; CEC, 2015b). Cooling the heated gas, prior to its entry into a combustion turbine, improves the efficiency of electricity generation (Maulbetsch, 2008; Sanders, 2015).

LITERATURE REVIEW: APPROACHES USED TO CHARACTERIZE POWER PLANT WATER USE

This section covers the range of published literature and methods characterizing water use at thermal power plants. The literature review starts with a national scale focus on the United States, and then focuses on California. The focus of this literature review is on the operations-related water use (i.e. directly associated with electricity generation) by power plants. Water use related to extraction, refining, processing, and transportation of fuels, or the construction of power plants is outside the scope of literature review. Studies that explore non-operations electricity related water use can be found elsewhere (Gleick, 1994; DOE, 2006; Pate, 2007; Mielke, 2010; Fthenakis, 2010; Wilson, 2012; McMahon, 2013; Water in the West, 2013; Meldrum, 2013; Spang, 2014).

Characterization by Water-Intensity Values

A water-intensity value is initially calculated by dividing the estimated, or in some cases actual reported, volume of water withdrawn/consumed by the amount of electricity generated, yielding intensity values in gallons/kilowatt-hour, gallons/MWh, or liters/MWh. One of the earliest operations water-intensity estimates in the United States came from Gleick (1994). In this paper, Gleick provided crude consumption estimates, separated by fuel type and cooling system. Only a single estimate was provided for each technology listed, based on the system's efficiency of conversion. A study by the Electric Power Research Institute (EPRI) provided improved estimates of operations bounded with a low-high range, and considered the influence of combined cycle technologies (Myhre, 2002). Related studies by the DOE (2006) and Sandia National Laboratories (SNL) (Pate, 2007) built on the previous EPRI estimates (Myhre, 2002) by including figures from more recent state and federal agency publications. A later study by the EPRI updated the water-intensity results of the Myhre (2002) study by including estimates for renewable sources, and also estimating the water-intensity of non-cooling system related power plant water uses (Maulbetsch, 2008). Fthenakis (2010) compiled water-intensity estimates from the previous work done by Gleick, EPRI, and DOE, but also added estimates from the National Energy Technology Laboratory (NETL), National Renewable Energy Laboratory (NREL), and SNL. Reports by Macknick (2011; 2012a) further improved operational water-intensity estimates by comprehensively surveying and summarizing the range of available studies done by academics, state and federal government agencies, non-governmental organizations, and industry permit submissions. The estimates, however, were not audited for accuracy, and inconsistencies in methods across studies were not accounted for (Macknick, 2011; 2012a). In these reports Macknick noted that improved power plant water data, and further studies at different climatic regions was needed for more accurate estimates. A similar approach was taken in Water in the West (2013), where some of the major studies (including Macknick's reports) were consolidated and summarized to compare water-intensities across fuel types, generation technology, and cooling technologies.

Finally, Meldrum (2013) applied the same level of rigor as Macknick (2011; 2012a) in surveying the full range of available literature, but this time applied a much stricter peer review process to determine acceptable sources. Furthermore, to reduce variation in the methods used between sources, Meldrum adjusted the previously published estimates, to the extent possible, by applying a common set of power plant performance parameters (referred to as harmonization), based on the power plant technology, prior to summarizing the data. Doing this ensured that the results were based on source estimates with a consistent set of methods and assumptions that no longer varied from study to study. Sensitivity analyses noted that the choice of harmonizing parameters chosen could make a significant difference in the results (Meldrum, 2013). Even with the harmonized estimates Meldrum concluded:

> “Despite extensive collection, screening, and harmonization efforts, gathered estimates for most generation technologies and life cycle stages remain few in number, wide in range, and many are of questionable original quality.”

The estimates by Macknick (2011; 2012a) and Meldrum (2013) have been used by researchers to calculate the volume of thermal power plant water use at regional and national scales (Cooley, 2011; Averyt, 2011), and global scales (Spang, 2014; Mekonnen, 2015). These estimates have been used for making projections about the future volume of thermal power plant water use (Macknick, 2012b; Tidwell, 2012; Yates, 2013; Clemmer, 2013). Another study used these estimates to determine thermal power plant contribution to water stress (Averyt, 2013a).

However, a weakness in relying on a set of estimates is that they do not factor in the variation caused by regional/local climate (e.g. seasons or interannual variability), regulations, water source and quality, thermal efficiency of the plant, and the age of the plant's equipment (Maulbetsch, 2008; Macknick, 2011; Macknick, 2012a), which may lead to inaccurate conclusions. In addition, some estimates were made using poorly documented methods that were not always thermodynamically realistic (i.e. did not follow the laws of physics) (Diehl, 2013).

The Heat Budget Method

Another method of estimating the water-intensity of power plants is to use "linked heat and water budget models" to bound thermal power plant water use estimates within thermodynamically plausible ranges (Diehl, 2013; Diehl, 2014). Heat budget models take local climate variables into account, unlike traditional water-intensity estimates (e.g. Macknick, 2011; Macknick, 2012a; Meldrum, 2013, etc.), which allows water-intensity values to be tailored to different regions by using the available climate data (Diehl, 2013; Diehl, 2014). This method can potentially be an accurate way to validate reported power plant water use, or to estimate water use when the data cannot be directly collected (Diehl, 2013; Diehl, 2014).

Although the heat budget method accounts for regional climate variations, there is still uncertainty resulting from the varying quality of the parameters (e.g. power plant technology, fuel characteristics, and climate variables) used in the model. These were shortcomings noted by Diehl (2013; 2014) that may have impacted the resulting water-intensity estimates, which Diehl (2014) reported to differ significantly, in some areas, from the estimates of Macknick (2011).

USGS Water Reports

A third approach used to characterize water use by power plants involves using the United States Geological Survey's (USGS) water use data. Broad, national-scale USGS thermal power plant water volume use estimates were commonly cited in the literature reviewed for the previous two sections. The USGS publishes a report every five years detailing the nation's water withdrawals by sector. Consumption data has not been reported since 1995, although efforts are in progress to re-introduce consumption reporting in the future (Maupin, 2014). Thermal power plant water withdrawals, compiled by cooling system type, are one of the sectors reported, along with irrigation, public-supply, and five other sectors. The most recently issued USGS water report characterized national water withdrawals for the year 2010 (Maupin, 2014), broken down by state. County-scale estimates, rather than watershed-scale, informed the state estimates (Maupin, 2014). To estimate thermal power plant water use, states either collected and reported withdrawals from thermal plants in their jurisdiction, used data collected by the EIA, or estimated the withdrawals using Diehl's (2013; 2014) linked heat and water budget model (Maupin, 2014).

In 2010, thermal power plants accounted for the majority of the nation's water withdrawals (Table 2). Presented are withdrawals with saline plus freshwater combined, and also freshwater withdrawals alone. Only self-supplied thermal power plant withdrawals were reported, while public supply deliveries were not (Maupin, 2014). The use of recycled water was also excluded (Maupin, 2014).

Table 2. The fraction of United States water withdrawals by sector (Maupin, 2014).

Sector	Billions of Gallons/Day (Saline Plus Freshwater)	Percent of Total (Saline Plus Freshwater)	Billions of Gallons/Day (Only Freshwater)	Percent of Total (Only Freshwater)
Thermal Power	160.9	45.3	117.0	38.2
Irrigation	115.0	32.4	115.0	37.6
Public Supply	42.0	11.8	42.0	13.7
All Others	37.1	10.5	32.0	10.5
Nationwide Total	**355.0**		**306.0**	

The numbers would appear quite different had water consumption data been collected by the USGS. The influence of once-through cooled plants dominated the nation’s thermal power plant water withdrawals, accounting for about 93 percent of the reported thermal power plant withdrawals, with wet-recirculating plants accounting for the remaining seven percent (Maupin, 2014). In 1995, the last time the USGS reported on water consumption, it was estimated that three percent of thermal power withdrawals ends up being consumed downstream of the discharge point (GAO, 2009). More recently, the USGS used the linked heat and water budget model from Diehl (2013; 2014), to survey 1,290 thermal power plants from across the country, finding that water consumption is still about three percent (Diehl, 2014). A study by the EPRI found the national water consumption of thermal power plants to be about four percent (Kannan, 2014). Assuming a three percent consumption rate, thermal power plants nationwide would consume roughly 4.8 billion gallons/day (freshwater plus saline), or about 3.5 billion gallons/day of only freshwater.

Two studies have made use of the USGS data to calculate the water-intensity of thermal power plants. First, a study by the NREL used USGS thermal power plant water use data, and EIA electricity generation data, to estimate the national and state-level average consumptive water-intensity of electricity generation in the United States (Torcellini, 2003). Second, a study by Cooley (2011) calculated the thermal power plant withdrawals for the Intermountain West, using water-intensity estimates from Macknick (2011), and then comparing the results with USGS data. The study found that, in 2005, the USGS underestimated the Intermountain West's thermal power plant water withdrawals by 50 percent (Cooley, 2011).

Energy Information Administration Data

A fourth method of characterizing thermal power plant water use, at the national or regional scale, is with data collected by the EIA. Currently, the EIA requires thermal power plants, with a nameplate capacity of 100 MW or greater, to annually self-report their cooling system and monthly cooling water use, at the generator level, with survey forms EIA-923 (schedule 8, part D), and EIA-860 (schedule 6, part D) (EIA, 2014; EIA, 2015; EIA, 2016). In the past, EIA-767 form was used, but has since been replaced by the EIA-923 and EIA-860 forms (EIA, 2015).

Reported EIA electricity generation and thermal power plant water use data has regularly been used by the NETL (Shuster, 2011) to calculate the water-intensity of the nation's thermal power plants. EIA cooling system and electricity generation data, has been used, along with water-intensity estimates from Macknick (2011), to calculate the volume of thermal power plant water use at national and regional scales (Averyt, 2011; Cooley, 2011). EIA thermal power plant data has also been used for projecting the volume of future thermal power plant water use (Shuster, 2011; Fisher, 2011; Chandel, 2011; Cooley, 2011).

Studies by Averyt (2011; 2013b) and Diehl (2014) suggested that the EIA data is of questionable quality because of inaccurate self-reporting by power plants. Based on their calculations using EIA data from the year 2008, Averyt (2011; 2013b) identified a range of apparent errors. However, it was noted that inaccuracies in the literature's water-intensity estimates, or misapplying literature coefficients to some power plants, could have also played a role in the perceived inaccuracy (Averyt, 2013b). A complete lack of water reporting was identified for more than 200 thermal coal and natural gas plants that reported millions of megawatt-hours of electricity generation (Averyt, 2011). Hundreds of power plants that did report their water use either over-reported (Averyt, 2011; Averyt, 2013b) or under-reported their water use (Averyt, 2013b). Some error was attributed to poorly documented, unstandardized methods used by plants that estimated their water use (Averyt, 2011). Outright data entry mistakes, such as mixing up withdrawals and consumption, were also reported by 22 power plants (Avery, 2011). In addition, Averyt (2011; 2013b) noted that a lack of specificity in identifying power plant water sources left a gap in the understanding of a power plant's contribution to, and risk of experiencing, water stress.

Inaccurate reporting is problematic because the EIA data is used by the USGS for at least some portion of their five-year water reports (Maupin, 2014), as described in the previous section. Furthermore, data quality issues make the assessment of current/future power plant water use trends, regional water conservation planning, and policy formation less certain (Averyt, 2011).

The California Perspective

The literature reviewed so far has tended to have a more national (DOE, 2006; Pate, 2007; Fthenakis, 2010; Averyt, 2011; Macknick, 2011; Macknick, 2012a; Water in the West, 2013; Averyt, 2013a; Meldrum, 2013; Diehl, 2013; Diehl, 2014; Maupin, 2014; Kannan, 2014), regional (Torcellini, 2003; Cooley, 2011), or global focus (Spang, 2014; Mekonnen, 2015). This section focuses specifically on thermal power plant water use in California.

USGS data for California

The 2010 USGS report (Maupin, 2014) not only listed national water withdrawal data, but also individual state-level water withdrawals. California's water withdrawal data, by sector, follows (Table 3). Presented are withdrawals with saline plus freshwater combined, and also freshwater withdrawals alone. Only self-supplied thermal power plant withdrawals were reported, while public supply deliveries were not (Maupin, 2014). The use of recycled water was also excluded (Maupin, 2014). When saline plus freshwater withdrawals were combined, thermal power plants accounted for roughly 17 percent of the state's water withdrawals, which was second to irrigation (~60 percent) (Table 3). When only freshwater withdrawals were considered, power plants accounted for a tiny fraction of the state's reported water withdrawals (0.2 percent) (Table 3).

Table 3. The fraction of California water withdrawals by sector (Maupin, 2014).

Sector	**Millions of Gallons/Day (Saline Plus Freshwater)**	**Percent of Total (Saline Plus Freshwater)**	**Millions of Gallons/Day (Only Freshwater)**	**Percent of Total (Only Freshwater)**
Thermal Power	6,600	17.4	65	0.2
Irrigation	23,100	60.8	23,100	74.3
Public Supply	6,300	16.6	6,300	20.3
All Others	2,000	5.2	1,635	5.2
State Total	**38,000**		**31,100.0**	

The numbers would appear quite different had water consumption data been collected by the USGS. As previously mentioned, water consumption data has not been collected since 1995. The influence of once-through cooled plants dominated the state's thermal power plant water withdrawals, accounting for about 98 percent of the reported thermal power plant withdrawals, with wet-recirculating plants accounting for the remaining two percent (Maupin, 2014). Assuming that national trends hold true in California, a three percent consumption rate would mean that thermal power plants consume roughly 200 million gallons/day (freshwater plus saline), or about two million gallons/day of only freshwater.

Examined by water source, California's thermal power plants used saline water for about 99 percent of the power plant withdrawals, and freshwater accounted for the remaining one percent (Table 3). Once-through cooled plants were reported to account for 99 percent of the saline water withdrawals, which is due to all of California's once-through cooled plants being located within close proximity to the coast and using ocean or brackish estuarine water for cooling (Maulbetsch, 2002; CEC, 2008).

EIA data for California

Currently, the EIA requires thermal power plants, with a nameplate capacity of 100 MW or greater, to annually self-report their cooling system and monthly cooling water use, at the generator level, with survey forms EIA-923 (schedule 8, part D), and EIA-860 (schedule 6, part D) (EIA, 2014; EIA, 2015; EIA, 2016). The EIA-860 survey form data lists the states where thermal power plants are located. This makes it possible to select for the thermal power plants located in California. When filtered, data for about 50-60 of California's thermal power plants are listed from year to year. In 2007, the CEC estimated that California had approximately 283 power plants, with nameplate capacities of 20 MW or greater, requiring water for cooling (CEC, 2008). The 283 power plants included combustion gas (simple cycle) turbines, which do not actually have a steam cycle that requires cooling water. In 2016, California appeared to have at least 179 operating thermal power plants with a nameplate capacity of 0.1 MW or larger (CEC, 2016f) that have a steam cycle (i.e. only steam turbines or combined cycle configurations) requiring cooling water.

California water-intensity studies

A number of CEC studies have looked into the water-intensity of California's power plants. The 2001 Environmental Performance Report (EPR) by the CEC gave some early water-intensity estimates, by cooling system and generation technology, but not fuel type, for some representative California power plants (CEC, 2001). The methods for arriving at the reported estimates were not specified. At that time, California's power plants consumed less than one percent of the state's total water demand (CEC, 2001). However, it was reported that impacts to local water supplies from a single plant could be significant relative to local supplies (CEC, 2001). Similar estimates were reported in a joint report by the CEC and EPRI (Maulbetsch, 2002), apparently drawing from, or informing, the 2001 EPR estimates. The 2003 EPR gave a single value estimate for the three main cooling systems (i.e. once-through, wet-recirculating, and air-cooled), stating that the lack of readily available power plant water use data significantly hampered the agency's ability to report on water use trends (CEC, 2003). The 2005 EPR (CEC, 2005) provided a better range of water-intensity estimates, except that these were mainly drawn from the literature values from the Hewlett Foundation (2003), which characterized power plant water use for the western United States, notably excluding California. The 2007 EPR (CEC, 2008) further improved on the 2005 EPR water-intensity estimates by factoring in the "data" (the exact type of data was not specified) reported by California power plants with a nameplate capacity of 50 MW of greater, representing about half of the state's electricity generators. It was acknowledged that the 2007 EPR estimates were limited because water use data for California's power plants was not readily available (CEC, 2008). The CEC did not begin collecting water use data from power plant owners until 2007 (CEC, 2008). Water-intensity estimates did not appear again in any CEC publications until the 2015 Integrated Energy Policy Report (IEPR) (CEC, 2015b). The estimates in the 2015 IEPR were derived by looking at the water use of representative California power plants, based on the CEC staff's knowledge and experience, combined with CEC QFER database information (Dennis, Christopher, personal communication, 2016).

Two academic studies were also encountered focusing on the water-intensity of California' electricity generation. First, a study by Larson (2007), presented the results, in brief, from a Master's thesis (Dennen, 2007) completed at the University of California at Santa Barbara, Bren School of Environmental Science and Management. The water-intensity estimates from a range of published literature, up to that point in time, were compiled and summarized (Dennen, 2007). The resulting estimates were then used, along with CEC power plant data, to calculate the power plant water use of four California counties (Dennen, 2007). Second, Fulton (2015) used the water-intensity estimates from Macknick (2011) and Meldrum (2013), along with CEC statewide electricity generation data, to calculate the change in the total water consumption of California's electricity generation infrastructure over time (Fulton, 2015).

California Energy Commission data

Similar to the EIA, the CEC collects water use data, at the generator level, for California's power plants, but the data is not restricted to thermal power plants. Form CEC-1304 (schedule 3, part A) requires power plants with a nameplate capacity of 20 MW or greater to report information regarding the plant's water use and cooling system (CEC, n.d.). At the time of this study, this form was a fillable Microsoft Excel spreadsheet, but will be made into an online submission process in the near future (Dennis, Christopher, personal communication, 2016). This power plant water use information is not publicly available online, but was shared via email by Christopher Dennis (Engineering Geologist with the CEC) (personal communication, 2016). The provided dataset contained monthly water use data, covering years 2010-2014, for about 290 of California's operating power plants that were 20 MW or greater, of which about 163 were thermal plants. However, the CEC has apparently not enforced the requirement to report the cooling system as required on the CEC-1304 instruction form (CEC, n.d.). Therefore, exact cooling system information (e.g. once-through, wet-recirculating, and air-cooled) was not available for many power plants.

LITERATURE REVIEW: DROUGHT AND WATER STRESS

This section starts by listing examples where drought and/or heat waves limited the water supply available for electricity generation at thermal power plants in the United States and internationally. Next, drought-induced water supply risks to California's thermal electricity generation are covered. Finally, studies looking at the influence of thermal electricity generation and other sectors on regional water stress are described, focusing specifically on the California region.

Impacts to Thermal Electricity Generation in the United States and Beyond

The following are examples of thermal power plants being shut down or curtailed because of drought and/or heat wave induced water shortage in the United States and internationally:

- In 2003, drought and heat wave forced France to reduce operations at many of its nuclear plants (Kimmell, 2009). Seventeen nuclear plants, including one coal plant, were shut down because water levels dropped below their intakes, while other nuclear plants were curtailed because the cooling water discharge temperature was too hot (Averyt, 2011; DOE, 2014). Similar shut downs and curtailments occurred in France during the heat waves of 2006 and 2009 (DOE, 2014).

- During a heat wave in 2006, high temperature river water forced four nuclear plants in Minnesota and Illinois to reduce output (Averyt, 2011).
- During a 2007 drought and heat wave, the Tennessee Valley Authority was forced to shut down or curtail operations at some nuclear and coal-fired plants (Kimmell, 2009). The Browns Ferry nuclear plant had to drastically cut its output in 2007, as well as in 2010, 2011, and 2012 (Averyt, 2011; Scanlon, 2013b) because cooling water discharge temperatures exceeded regulations. Duke Energy also had to cut output at its G.G. Allen and Riverbend coal plants for the same reason (Averyt, 2011). Duke Energy was later forced to modify an intake pipe on one of its nuclear plants to stay in reach of the dropping water level at Lake Norman (Averyt, 2011).
- A 2011 drought in Texas forced at least one power plant to cut its output because the temperature of the cooling water source was too high, while other plants had to pipe in water from new sources due to local water shortage (Averyt, 2011).
- In 2012, drought and heat wave forced the Millstone Nuclear Plant in Connecticut to shut down because of high temperature cooling water (Scanlon, 2013b). The Gallatin and Cumberland coal plants in Tennessee, Powerton coal plant in Illinois, and a nuclear plant in Vermont were also forced to reduce output or shut down for the same reason (Rogers, 2013).

Kimmell (2009) noted that most documented examples of power plant curtailments or shut downs have been due to temperature regulations, rather than physical water shortage where water dropped below intake levels. Regulatory curtailments or shut downs for exceeding temperatures limits of discharged cooling water are not always set in stone. For example, during the 2012 drought, some United States power plants were given exemptions by regulatory agencies to discharge even higher temperature water so that they could continue operating (Rogers, 2013). During the 2003 drought in France, some nuclear plants were also given temporarily higher discharge temperature limits so that they could keep operating (Scanlon, 2013b; DOE, 2014).

Water Supply Risks to California's Thermal Power Plants

The CEC has identified a number of water supply risks that may impact California's thermal power plants during drought. These included curtailment of federal and state water project deliveries, water rights seniority issues, reduced recycled water availability, insufficient water storage, and depleted groundwater levels (CEC, 2015b).

After reviewing the scientific literature, California Independent System Operator (CAISO) seasonal assessment reports, and CEC EPR and IEPR publications, no examples could be found where water shortage or water temperature issues resulted in the curtailment or shutdown of California's thermal power plants. However, in 2014, four natural gas plants were at-risk of water shortage (Infrastructure Development, 2014; Infrastructure Development, 2015). These power plants mitigated the issue in 2015 by either establishing alternative water supplies, or by changing the management of the groundwater supply being used (Infrastructure Development, 2015; CEC, 2015b).

Even though the most recent multi-year drought severely reduced hydroelectric generation (Figure 4, and Table 1), CAISO continued to project a sufficient electricity generation reserve margin throughout the state during the 2014, 2015, and 2016 peak summer months (Infrastructure Development, 2014; Infrastructure Development, 2015; California ISO, 2016). After accounting for hydropower reduction, modeled under extreme scenarios, the CAISO Operator projected reserve margins that were generally "well above" the three percent load shedding threshold that would begin to trigger rolling blackouts (Infrastructure Development, 2014; Infrastructure Development, 2015; California ISO, 2016). The reliability was attributed to the significant addition of new renewable generation (overwhelmingly solar), sufficient imports, and moderate peak demand growth (Infrastructure Development, 2014; Infrastructure Development, 2015; California ISO, 2016).

Regional Water Stress Trends for California

There have been a few national-scale studies that looked at the influence of thermal electricity generation and other sectors on regional water stress (Roy, 2011; Roy, 2012; Averyt, 2011; Averyt, 2013a; Tidwell, 2012). These studies were all similar in computing a ratio that compared regional water demands to regional water supplies. Roy (2011; 2012) looked at water stress at the county level by comparing water withdrawals to available precipitation (the remaining runoff after subtracting precipitation that evapotranspirates). Averyt (2011; 2013a) looked at water stress at the Hydrologic Unit Code 8 (HUC-8) watershed level by comparing water demands to the available supply using a Water Supply Stress Index (WaSSI) model. Tidwell (2012) looked at water stress at the HUC-6 level by comparing water demands to the water supply.

Focusing on California, all of these studies revealed that much of the Central Valley and southern California should theoretically be experiencing severe water stress because water demands already exceed the natural water supplies in these areas. However, these studies acknowledged that they did not consider the influence of water transfers, storage (e.g. reservoirs), recycled water, and groundwater overdraft that supplements the water supply in perceivably stressed regions (Roy, 2011; Roy, 2012; Averyt, 2011; Averyt, 2013a; Tidwell, 2012). Scanlon (2013b) stated that water stress indexes do not account for the coping strategies that power plants have developed to deal with conditions at the local level.

Another weakness of these studies is that they used 2005 USGS data for the water demands, which limits the analysis to withdrawals, unless 1995 data is used to estimate consumption as done in Tidwell (2012). Lastly, water stress metrics rely on averages, which ignores the annual/seasonal variation in demands and supplies (Roy, 2011; Roy, 2012; Averyt, 2011; Averyt, 2013a).

METHODS: ESTIMATING THE CONSUMPTIVE WATER-INTENSITY OF CALIFORNIA'S POWER PLANTS

Power plant water use data for this study was provided by Christopher Dennis, Engineering Geologist, of the California Energy Commission (CEC), and includes power plants with a nameplate capacity of 20 MW or greater (Dennis, Christopher, personal communication, 2016). The original dataset contained about 290 power plants that were 20 MW or greater, covering years 2010-2014, and was reported at the generator level by power plant identification number (ID). When available, this data also included the geographic coordinates, water source, and water type used by the power plants. Gross electricity generation data was acquired from the CEC QFER database at the generator level (CEC, 2016d). However, the analysis was done at the power plant level because there were too many cases where the generator IDs for water use and electricity generation did not match up. Monthly generator unit gross electricity generation was summed to the power plant ID level (CEC, 2016d). The monthly generator unit water use data was also summed to the power plant ID level. Power plant water use data collection began in 2007, but the data had not been well checked prior to 2010 (Dennis, Christopher, personal communication, 2016). Correcting mistakes in the data was an iterative process throughout this study.

Water Use Codes Reported to the CEC

Power plants report a number of different water use codes to the CEC. These codes will be referred to going forward (Table 4).

Table 4. Description of the water use codes reported in the CEC data.

Water Use Code	**Description**	**Notes**
BMW	Boiler Makeup Water	Boiler water is replaced from time to time.
DS	Dust Suppression	
GB	Generator Bearings	
IAC	Inlet Air Cooling	Generally, only reported by plants with combustion gas turbines, either simple or combined cycle.
IC	Intercooling	Generally, only reported by plants with combustion gas turbines, either simple or combined cycle.
L	Landscaping	
Nox	Nitrogen dioxide control	Emissions control.
OC	Other Cooling related water use	
OW	Other Water use	Non-cooling related water uses that do not fit in the other categories.
Plant Total	Total of all plant water uses	Used when plants cannot report individual codes.
PW	Panel Washing	Only applies to solar.
SD	Sanitation and Drinking	Employee restrooms, sinks, drinking fountains, etc.
SCC	Steam Cycle Cooling	Cooling system water used to re-condense steam inside the boiler.

Analyzing the Initial Data Quality

The CEC power plant dataset was initially examined for obvious errors. Mislabeled plant IDs were identified and corrected. Water use codes were made more uniform across the entire dataset when variations of the same code were encountered. Plants with a nameplate capacity below 20 MW (summed across all generator units) were removed because regulations only require plants at or above 20 MW nameplate capacity to self-report their water use (CEC, n.d.). Plants smaller than 20 MW that reported are not subject to the same scrutiny by the CEC, making their reporting less reliable. The geographic coordinates for each CEC plant ID were also checked for accuracy, corrected where necessary, and missing coordinates added by using a separate dataset provided by Christopher Dennis (personal communication, 2016).

Acquiring Additional Power Plant Information

The generation technology for each generator (e.g. steam cycle turbine, combustion gas (simple cycle) turbine, combined cycle turbine, internal combustion engine, etc.) was acquired from the CEC QFER database (CEC, 2016e). This allowed a better understanding of power plants that should require cooling water (i.e. the Steam Cycle Cooling code) for electricity generation. Once-through cooled power plants were identified using the QFER database (CEC, 2016d). A list of air-cooled plants licensed by the CEC was used to identify plants that are air-cooled (Dennis, Christopher, personal communication, 2016). Only power plants greater than 50 MW in nameplate capacity are required to be licensed by the CEC. The list of air-cooled plants was cross-referenced with data from the EIA (2016) to verify which plants were air-cooled.

One power plant (Humboldt Bay Generating Station) was listed as both once-through cooled and air-cooled. Further investigation revealed that this power plant retired its once-through cooled generator in 2010, and was upgraded to air-cooled for years 2011-2014. The data for 2010 was not considered for the water-intensity analysis because the reporting was impacted by the upgrade process. The plant was treated as air-cooled for this study.

Removing Water Uses Not Related to Electricity Generation

Water use codes that did not directly impact electricity generation were removed. This included the Landscaping, and Sanitation and Drinking codes, water uses that could be considered characteristic of any large facility. During a drought, for instance, these water uses could be reduced without any impact to electricity generation. Including the Landscaping, and Sanitation and Drinking water codes would inaccurately bias the water-intensity results.

The Other Water use code was considered for removal as well, but was ultimately left in place because there was evidence that some plants were incorrectly reporting electricity generation-related water uses (e.g. Steam Cycle Cooling, Inlet Air Cooling, Intercooling, Boiler Makeup Water, Other Cooling) under this code.

Removing Power Plants with Low Electricity Generation

Power plants with an annual electricity generation of less than 500 MWh were removed. Nearly all power plants reported an annual electricity generation of over 500 MWh.

Adjustments Made to Once-Through Cooled Water Use

In the CEC power plant dataset, once-through cooled plants only reported water withdrawals, while all other power plants only reported consumption (Dennis, Christopher, personal communication, 2016). In order to directly compare the water use of once-through cooled plants with all other plants, the water withdrawals were converted to water consumption. The fraction of withdrawals from once-through cooled plants that ends up consumed after release into the environment has been relatively poorly studied, but the most commonly reported estimate hovers around one percent (Myhre, 2002; Kannan, 2014). However, it must be noted that once-through cooled consumption estimates were never modeled for plants using saline water (which is what California's once-through cooled plants run on). The water withdrawals of once-through cooled plants was multiplied by a factor of 0.01 to represent an estimated one percent consumption fraction. From this point forward, all water use represents consumption, unless stated otherwise.

Matching Up Water Consumption with Electricity Generation

Each power plant's water consumption was combined with its gross electricity generation for each of the study years. After matching up the water use and electricity generation data sets, water consumption values were divided by electricity generation to calculate the annual consumptive water-intensity of each power plant in gallons/MWh.

Scrutinizing the Initial Annual Water-Intensity Results for Apparent Errors

The initial power plant level consumptive water-intensity results were closely scrutinized by comparing the estimates, as well as the pattern of reported water use codes, from year to year. Large variations between years were discovered (two or more orders of magnitude for an individual plant at times) for nearly 25 percent of the power plants, thus leading to an investigation into the causes of this variation. After contacting the CEC, numerous power plants were found to contain data entry, and/or water use code reporting errors for specific months, or an entire year(s). Data entry errors were fixed whenever the CEC could confirm the error and provide the correct data. Sometimes this meant correcting typos, other times this meant inputting water use data that had been inadvertently excluded. If water use code reporting errors could be identified, but not corrected within the time frame of the study, then the erroneous year(s) was removed from the analysis. In most cases, a single erroneous water use code was found to have been added or omitted for only a single year.

In some cases, the pattern of reported codes from the most recent two or three years differed significantly (by two or more orders of magnitude) from the pattern of the previous two or three years. Where the data presented this type of discontinuity, the more recent period of time was used as this reflects the current state of water use at the plants in question. This choice was further justified by the fact that the data quality of the most recent years had been checked more thoroughly than older years (Dennis, Christopher, personal communication, 2016).

Re-Calculating the Water-Intensity Estimates

After correcting data entry errors, and removing inaccurately reported data, the 5-year weighted average annual (or weighted annual average for the number of years available if less than five) consumptive water-intensity was calculated for each power plant. Averages were categorized by generation technology, cooling system, and fuel type when possible.

METHODS: ESTIMATING POWER PLANT CONTRIBUTION TO REGIONAL WATER STRESS

California Department of Water Resources Water Plan Data

A 2013 Water Plan Update dataset was downloaded (CDWR, 2015) giving the breakdown of California urban, agricultural, and environmental water withdrawals and consumption (referred to as applied and depleted, respectively in the original dataset) for water years 1998-2010 (a water year runs from October 1st – September 30th) at the "planning area" scale. The data for water years 2011-2015 will not be available until the 2018 Water Plan Update is released. The CDWR divides California into 10 hydrologic regions, and further into 56 planning areas (Figure 9). Planning areas are further broken down into hundreds of "detailed analysis units" (not shown). The CDWR aggregates the water balance data from the detailed analysis units to form planning area estimates. According to the 2013 Water Plan glossary, urban water use encompasses water for energy production, specifically water used by refineries and water for cooling in thermal electricity generation. Water sources in the CDWR data includes surface water, deliveries/transfers from local, state, and federal water systems, groundwater extraction, and reused/recycled water.

Figure 9. California Water Plan planning areas nested within their respective hydrologic region. Hydrologic region and planning area layers acquired from the CDWR (2013b).

Determining Regional Human Water Demands

To estimate the amount of water humans consume in each planning area, the urban and agricultural water consumption for water years 1998-2010 was averaged and then summed at the planning area scale.

Determining Regional Power Plant Water Consumption

To estimate how much freshwater is consumed by power plants in each planning area, the individual power plant water consumption data was averaged over the 2010-2014 period, and then summed at the planning area scale.

The 14 once-through cooled power plants were not considered for this part of the analysis. There were two reasons for this decision. First, California's once-through cooled plants are all located along the coast, and rely on ocean or brackish estuarine water for cooling. They would cause negligible impact to California's freshwater resources, and by extension water scarcity. Second, by the year 2030, all once-through cooled generators will be phased out in California, as previously mentioned in the Background sub-subsection titled "A shift away from once-through cooling."

The 32 geothermal plants were also not considered for this part of the analysis as the focus is on freshwater consumption and scarcity, whereas geothermal power plant rely heavily on the onsite geothermal fluid reservoir, making them resistant to drought. In addition to using onsite geothermal fluids, many geothermal plants also have some amount of outside water imported for cooling, or for recharging the geothermal aquifer (Dennis, Christopher, personal communication, 2016). However, distinguishing the amount of water consumption that can be attributed to outside water sources versus onsite geothermal fluids is not possible by looking at the data. Therefore, determining the potential contribution of geothermal plants to water stress was deemed too uncertain for this study.

Estimating Power Plant Contribution to Regional Water Stress

To estimate the contribution of power plants to regional water stress, the regional power plant water consumption was compared to the regional human consumption. A ratio was calculated in each planning area with the following formula:

$$\text{Power Plant RWS} = \frac{\bar{A}\text{ppc}}{\bar{A}\text{uc} + \bar{A}\text{ac}}$$

In the equation above RWS is regional water stress, $\bar{A}_{ppc}$ is the sum of the region's average power plant consumption values, $\bar{A}_{uc}$ is average urban consumption, and $\bar{A}_{ac}$ is average agricultural consumption. The sum of both terms in the denominator represents the total human consumption for a given region.

Sensitivity tests were conducted to test the impact of substituting the average power plant consumption for the highest water consumption year for each power plant, and substituting the average human water consumption for the year where human water consumption was at a minimum. Thus, these tests artificially maximized the Power Plant

RWS ratio to determine the maximum potential power plant contribution to regional water stress.

METHODS: IDENTIFYING POWER PLANTS LOCATED IN REGIONS OF HIGH WATER STRESS

Determining the Available Regional Water Supply

The 2013 Water Plan Update dataset (CDWR, 2015) was also used to estimate the available water supply in each planning area. The urban, agricultural, and environmental water withdrawals for water years 1998-2010 were averaged and then summed at the planning area scale. Environmental water use was added in as part of the available water supply because some planning areas preserve large fractions of their water supply for environmental purposes (e.g. maintaining river flows to protect fish, wildlife, aquatic ecosystems, and water quality).

It is important to realize that the total withdrawals from the urban, agricultural, and environmental sectors in the CDWR dataset not only represents water withdrawals, but also the water supply (made) available to a given area. This is true because in addition to surface water withdrawals, it also includes deliveries/transfers from local, state, and federal water systems, groundwater extraction, and reused/recycled water. Without these additional water sources, many areas of California would exceed the natural water supply of the area as shown in other water stress studies (Roy, 2011; Roy, 2012; Averyt, 2011; Averyt, 2013a; Tidwell, 2012). In California, calculating water stress ratios by only considering natural runoff would yield ratios exceeding 100 percent in many areas of the state. Therefore, the influence of water deliveries, groundwater extraction, and reused/recycled water must be considered for a more accurate representation of the water supply made available to a given region.

Identifying Regions Most At-Risk of Experiencing Water Stress

To estimate the relative water stress in each planning area, human water demands (agricultural plus urban consumption) were compared to the available water supply (agricultural withdrawals, urban withdrawals, and environmental water use). The water stress ratio was calculated in each planning area with the following formula:

$$\mathrm{RWS} = \frac{\bar{A}uc + \bar{A}ac}{\bar{A}uw + \bar{A}aw + \bar{A}ewu}$$

In the equation above RWS is regional water stress, $\bar{A}_{uc}$ is average urban consumption, $\bar{A}_{ac}$ is average agricultural consumption, $\bar{A}_{uw}$ is average urban withdrawals, $\bar{A}_{aw}$ is average agricultural withdrawals, and $\bar{A}_{ewu}$ is average environmental water use. The sum of terms in the numerator represents the total regional human consumption, while the sum of terms in the denominator represents the total regional water availability.

Sensitivity tests were conducted to test the impact of annual precipitation extremes on the RWS ratio by using the data for two particularly wet years (1998 and 2006), and two particularly dry years (2001 and 2007). A sensitivity test was also conducted to test the impact of excluding environmental water use from the available water supply.

RESULTS: ANALYZING THE QUALITY OF THE DATA

Checking the Initial Data for Errors

Out of about 306 unique power plant IDs in the initial data set, 16 were removed because they were less than 20 MW in nameplate capacity. One additional power plant was removed because no electricity generation data was reported. An additional 25 plants were removed because they did not report any water use data, with most stating that they were “not metered.”

After verifying the geographic coordinates, seven of the remaining power plants were removed that are not physically located in California. These included two natural gas plants in Mexico, three solar PV plants in Arizona, one natural gas plant in Nevada, and one coal plant in Utah.

Verifying the Air-Cooled Power Plants

When the CEC dataset was cross-referenced with EIA (2016) data to verify California’s air-cooled generators, one additional air-cooled generator (plant ID G0838) was discovered. This power plant had a nameplate capacity of 166 MW.

Removing Water Uses Not Related to Electricity Generation

Removing water use codes not directly related to electricity (i.e. Landscaping, and Sanitation and Drinking) generation led to the complete removal of 11 plants from consideration because no other water uses were reported. Of these, five were solar PV, one combustion gas (simple cycle), two combined cycle, and three steam cycle power plants.

The Other Water code appeared to have been used incorrectly by a number of power plants. There were three examples of plants with only a steam turbine that reported all, or the vast majority, of the water use as the Other Water code, but none as Steam Cycle Cooling. Furthermore, there were 11 examples of combined cycle plants that reported Other Water codes, but no Steam Cycle Cooling codes even though they reported electricity generation from their steam turbines.

Removing Power Plants with Low Electricity Generation

Removing years where power plants had a gross electricity generation of less than 500 MWh only resulted in the removal of five total years worth of data from four individual power plants. All other power plants had higher annual electricity generation. Four of these years were from three power plants that had a reported electricity generation of five MWh or less, while the last power plant reported electricity generation slightly over 130 MWh.

Scrutinizing the Initial Annual Water-Intensity Results for Apparent Errors

Upon noticing large inconsistencies in the initial interannual water-intensity results (variation of two or more orders of magnitude at times for a given power plant), and subsequently contacting the CEC, numerous data entry and/or reporting errors were discovered. Data entry errors were corrected. Years containing water use code reporting errors could often be confirmed, but not corrected within the time frame of this study. Such reporting error years were removed. Six power plants had such inconsistent interannual reporting of water volume and/or water use codes (where the annual water-intensities varied by two or more orders of magnitude) that these plants were completely removed because the data could not be trusted.

RESULTS: ESTIMATING THE CONSUMPTIVE WATER-INTENSITY OF CALIFORNIA'S POWER PLANTS

Water Use Summarized by Code

To give a sense of the relative importance of each type of water use code by California's power plants, the reported water use for both once-through cooled plants (Figure 10), and non-once-through cooled plants was summarized with bar charts, broken down by fuel type (Figures 11 through 16). Summary figures were also created for combined cycle, combustion gas (simple cycle), and air-cooled power plants (Figures 17 through 19). Once-through cooled plants were separated from the other power plants because they only reported water withdrawals, whereas other power plants only reported water consumption. All of California's once-through cooled plants, except for a single nuclear plant, are fueled by natural gas. With the exception of solar PV, air-cooled, and combustion gas (simple cycle) power plants, Steam Cycle Cooling is the dominant water use by California's power plants. Solar PV plants were dominated by Dust Suppression, while air-cooled and combustion gas (simple cycle) plants were dominated by Other Water. The Landscaping, and Sanitation and Drinking codes generally made up less than one percent of the water use reported by power plants. See Appendix A and Appendix B for the data tables used to derive Figures 10 through 19.

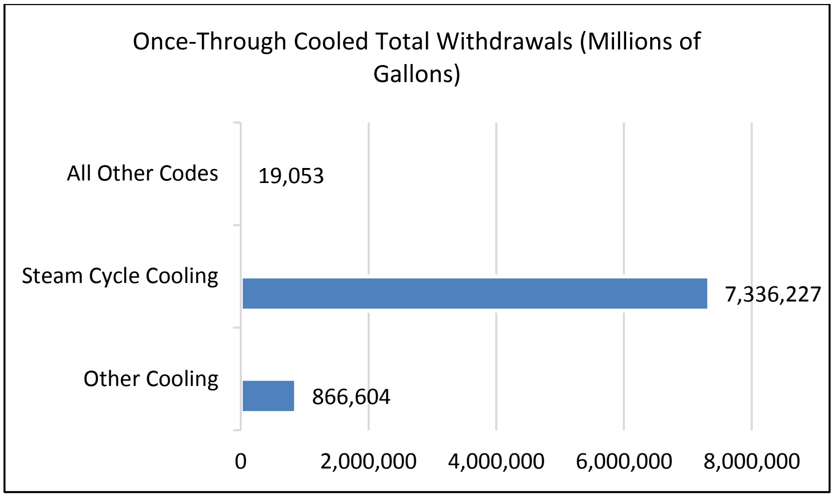

Figure 10. The fraction of each water use code reported by once-through cooled plants.

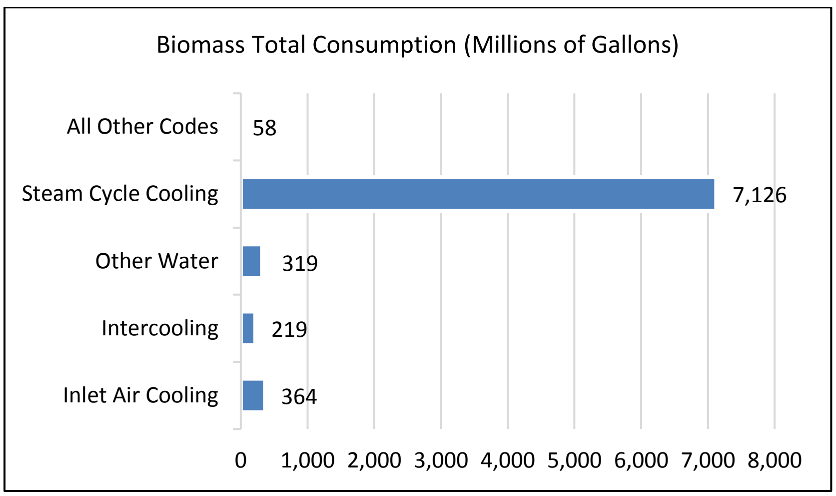

Figure 11. The fraction of each water use code reported by non-once-through cooled biomass plants.

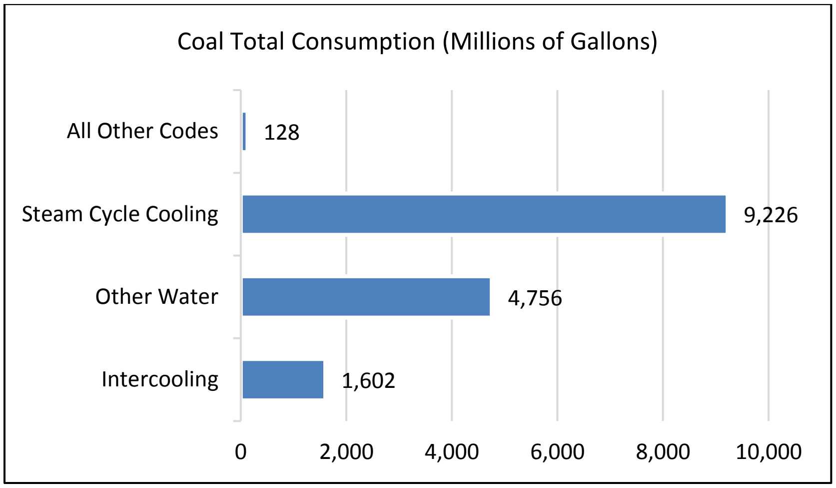

Figure 12. The fraction of each water use code reported by non-once-through cooled coal plants.

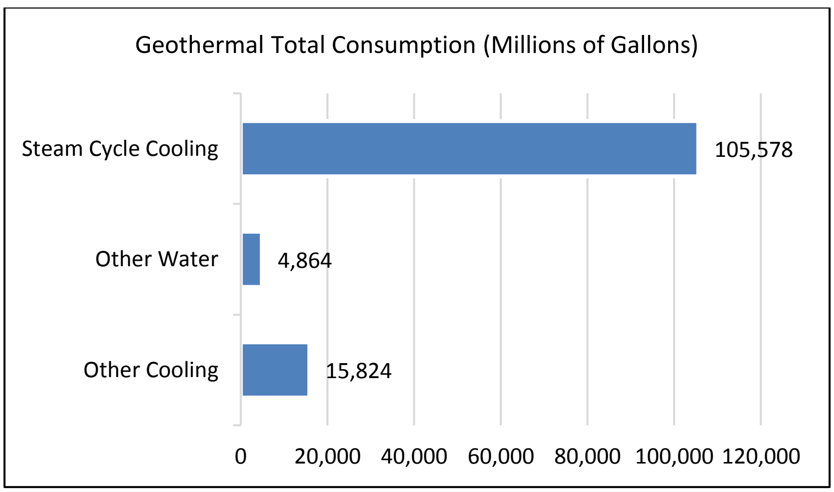

Figure 13. The fraction of each water use code reported by non-once-through cooled geothermal plants.

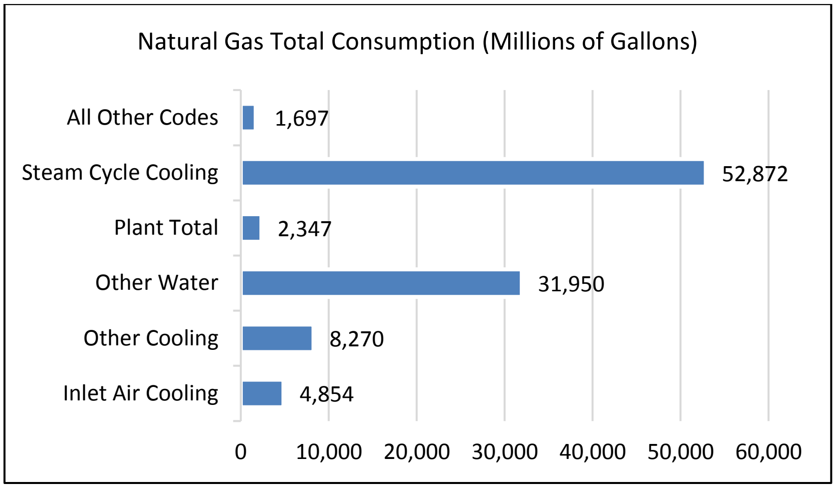

Figure 14. The fraction of each water use code reported by non-once-through cooled natural gas plants.

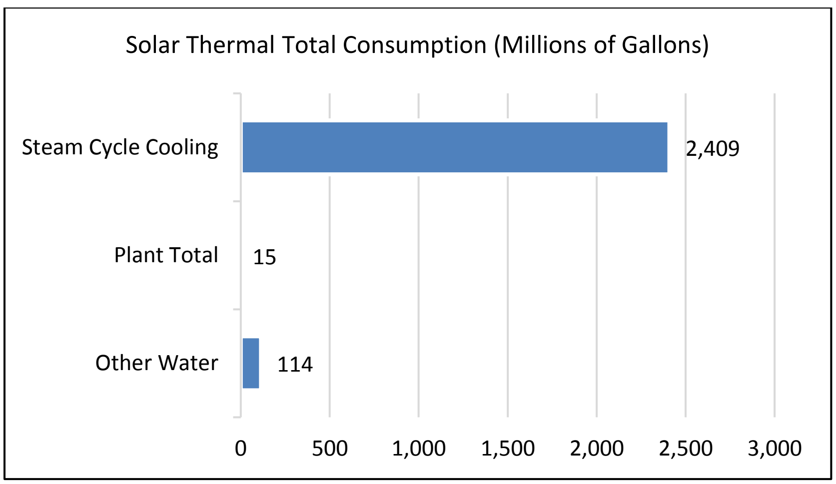

Figure 15. The fraction of each water use code reported by non-once-through cooled solar thermal plants.

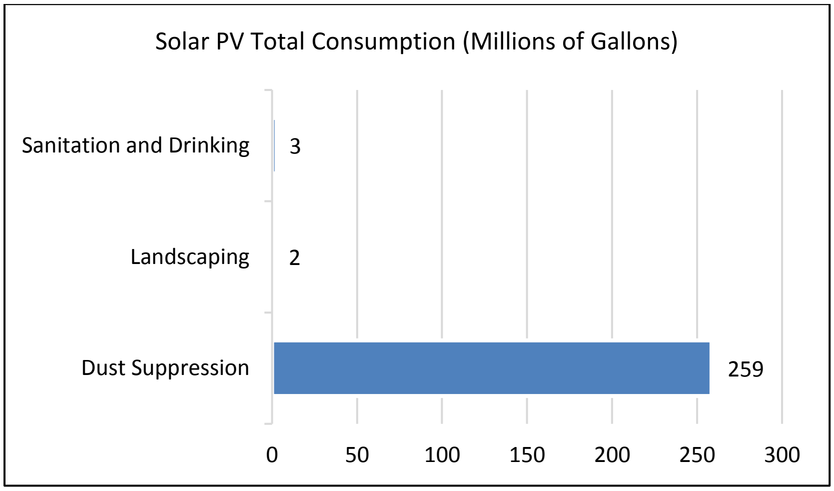

Figure 16. The fraction of each water use code reported by non-once-through cooled solar PV plants.

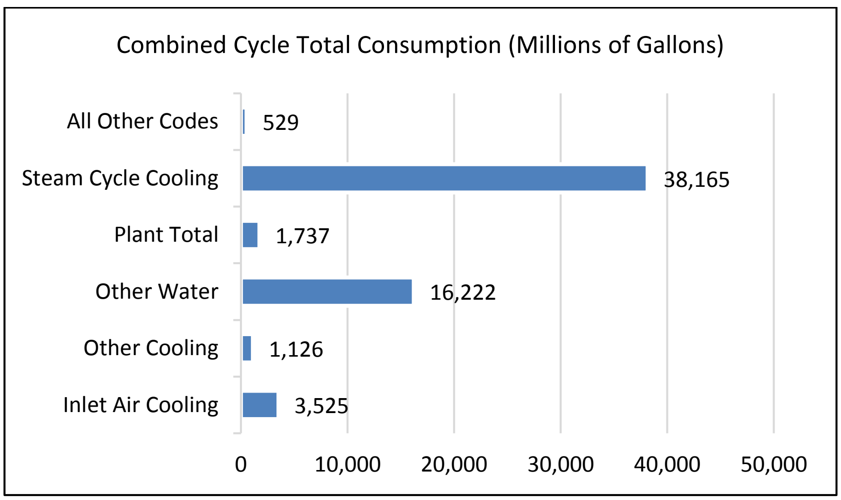

Figure 17. The fraction of each water use code reported by non-once-through cooled combined cycle plants.

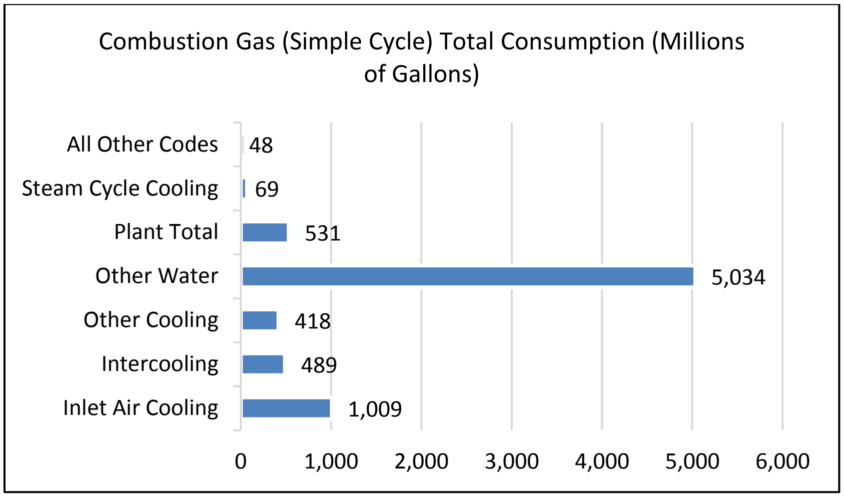

Figure 18. The fraction of each water use code reported by non-once-through cooled combustion gas (simple cycle) plants.

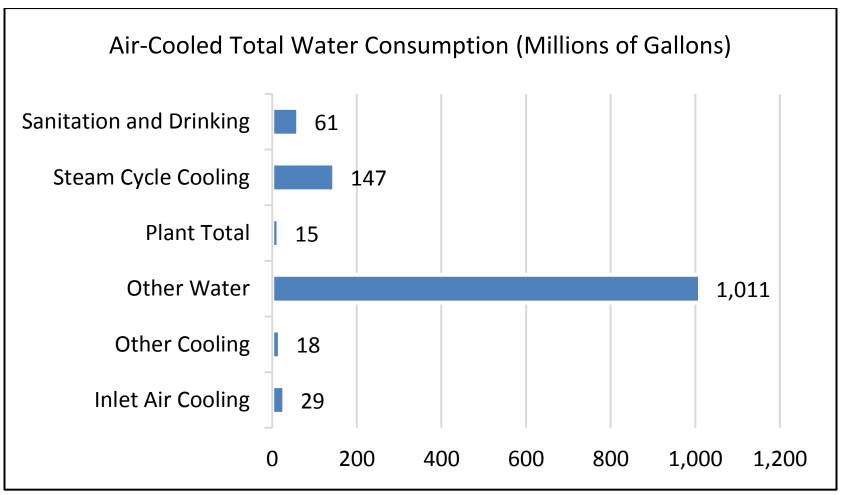

Figure 19. The fraction of each water use code reported by air-cooled plants.

Some figures illustrate what appear to be incorrectly reported water use codes. A few biomass and coal plants reported Inlet Air Cooling and/or Intercooling (Figure 11 and Figure 12), even though these power plants only have steam turbines. Inlet Air

Cooling and Intercooling is generally only associated with combustion gas turbines (either simple cycle or combined cycle). In contrast, a few combustion gas (simple cycle) and air-cooled power plants reported Steam Cycle Cooling (Figure 18 and Figure 19), even though combustion gas (simple cycle) power plants do not have a steam turbine, and air-cooled power plants do not circulate cooling water for re-condensing steam inside of the boiler.

Consumptive Water-Intensity Estimates

The 5-year weighted average annual consumptive water-intensity results were generalized to display power plants with a single cooling system, generation technology, and/or primary fuel type (Table 5). Power plants with multiple generation technologies or fuel types are not shown. The minimum and maximum 5-year weighted average annual consumptive water-intensities were also listed to give a sense of the range of average water-intensity values for a given combination of technologies. Technology categories beginning with the label “steam turbine” or “combined cycle” most likely represented wet-recirculating cooled power plants, but this is not known with 100 percent certainty. There is a small chance that a few air-cooled plants may have been included in these categories, particularly the combined cycle category. The CEC could not provide a definitive list with the cooling systems of all of its power plants.

Table 5. Consumptive water-intensity results (gallons/MWh). The 5-year weighted annual average, minimum, and maximum are shown for each technology category.

Generation Technology	Number of Plants	Weighted 5-Year Annual Average	Weighted 5-Year Annual Minimum	Weighted 5-Year Annual Maximum
All Air-Cooled	11	27	0.3	107
Air-Cooled Combined Cycle Natural Gas	5	13	6	30
Air-Cooled Solar Thermal	4	14	8	29
All Once-Through Cooled	14	545	252	1,985
Once-Through Natural Gas	7	782	557	1,301
Once-Through Nuclear	1	465 (only 1 year of data)	N/A	N/A
Combined Cycle Natural Gas	43	278	0.4	868
Combined Cycle Single Shaft Natural Gas	3	265	225	294
All Steam Turbine	62	1,734	192	4,170
Steam Turbine Coal	8	1,130	559	2,407
Steam Turbine Geothermal	32	2,035	192	4,170
Steam Turbine Natural Gas	3	803	584	2,151
Steam Turbine Solar Thermal	8	879	586	1,771
Steam Turbine Wood Biomass	8	702	629	1,082
Combustion Natural Gas (Simple Cycle)	81	128	0.02	1,102
Solar PV including Dust Suppression	8	99	0.2	233
Solar PV excluding Dust Suppression	6	0.7	0.2	3

Box and whisker plots were created to show the distribution of 5-year weighted average annual consumptive water-intensities for the air-cooled technologies (Figure 20). The highest water-intensity air-cooled plant (plant ID G0161) had a 5-year weighted annual average of 107 gallons/MWh and was clearly an outlier. This was notably the only air-cooled plant that also employed cogeneration. Without this plant, the weighted average for all air-cooled plants dropped to 13 gallons/MWh.

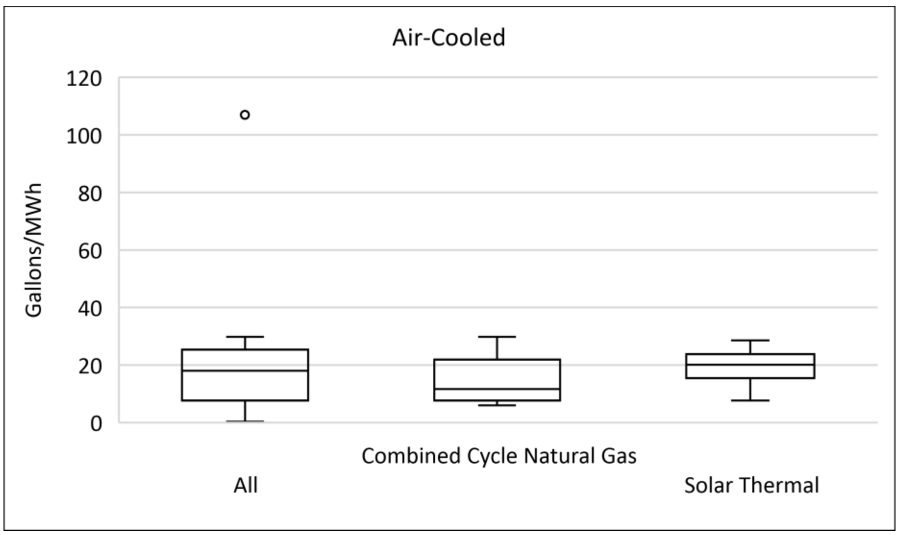

Figure 20. The 5-year weighted average annual consumptive water-intensities of air-cooled power plant technologies. The box represents the interquartile range with the center line representing the median. The whiskers represent the minimum and maximum values. Circles represent outliers.

Box and whisker plots were created to show the distribution of 5-year weighted average annual consumptive water-intensities for the once-through cooled technologies (Figure 21).

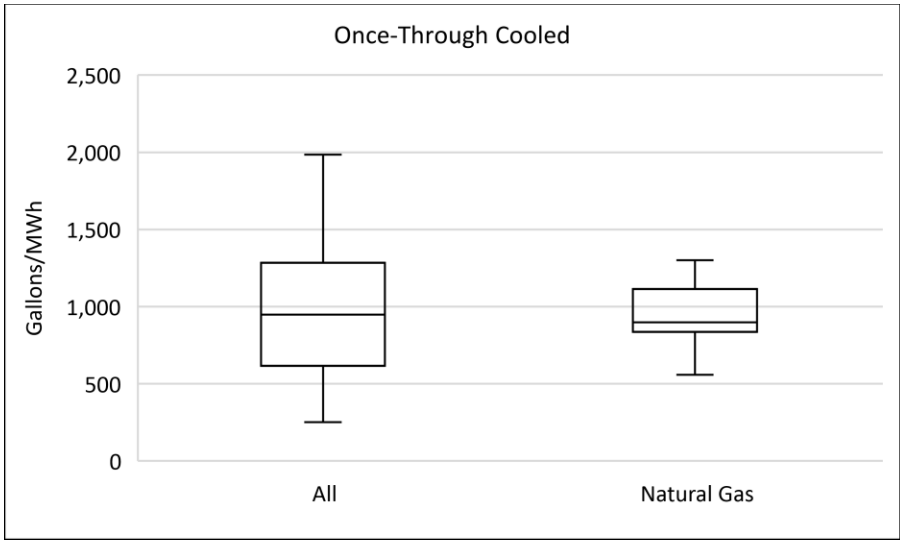

Figure 21. Box and whisker plot showing the 5-year weighted average annual consumptive water-intensities of once-through cooled power plant technologies.

Box and whisker plots were created to show the distribution of 5-year weighted average annual consumptive water-intensities for the combustion natural gas (simple cycle), and combined cycle natural gas plants (Figure 22). Simple cycle natural gas plants had a lower weighted average consumptive water-intensity, and interquartile range (25th to 75th percentile) than combined cycle natural gas plants (Table 5 and Figure 22).

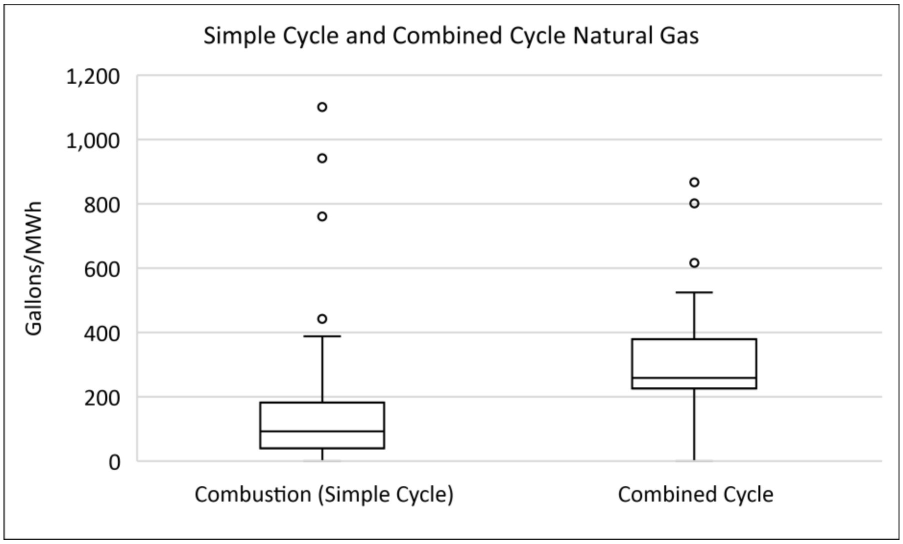

Figure 22. Box and whisker plot showing the 5-year weighted average annual consumptive water-intensities of combustion natural gas (simple cycle) and combined cycle natural gas power plants.

Box and whisker plots were created to show the distribution of 5-year weighted average annual consumptive water-intensities for the steam turbine technologies (Figure 23). Geothermal plants generally had a higher 5-year weighted annual average, and interquartile range (25th to 75th percentile) than any other steam turbine plant category (Table 5 and Figure 23). The weighted average for all steam turbine plants (Table 5) fell from 1,734 to 897 gallons/MWh if geothermal plants were excluded.

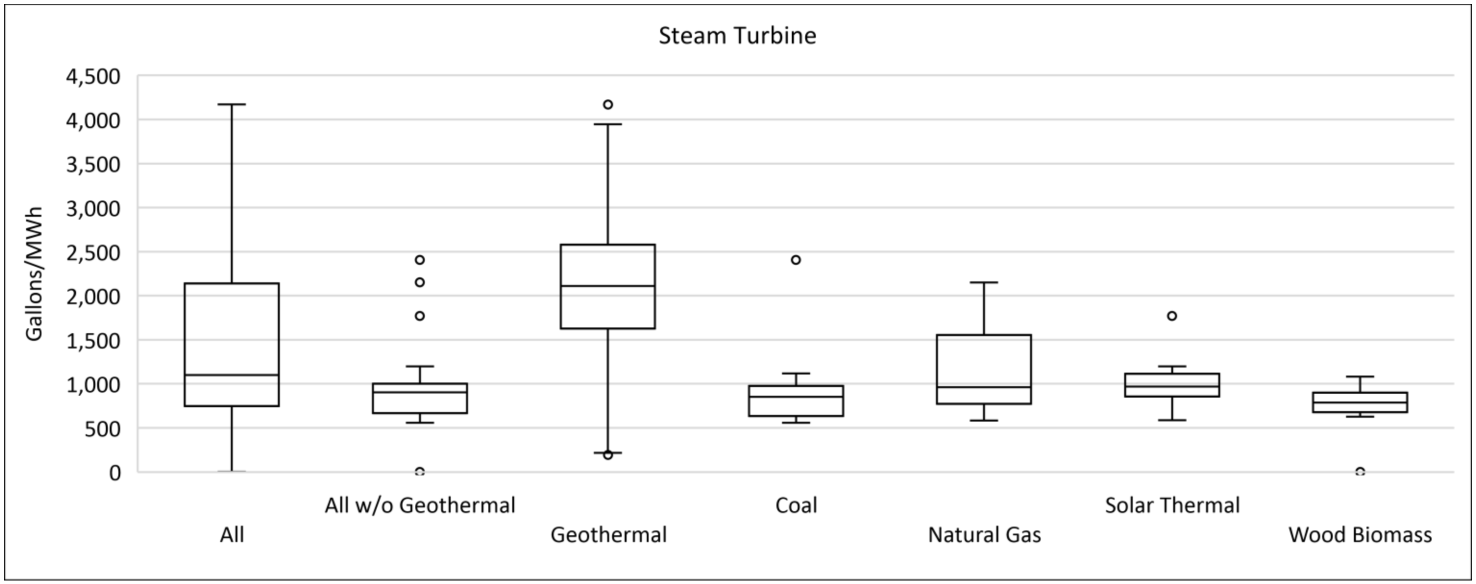

Figure 23. Box and whisker plot showing the 5-year weighted average annual consumptive water-intensities of steam turbine power plant technologies.

Box and whisker plots were created to show the distribution of 5-year weighted average annual consumptive water-intensities for the solar PV plants (Figure 24). The 5-year weighted average annual consumptive water-intensity depended significantly on the inclusion or exclusion of Dust Suppression water use (Table 5). The 5-year weighted annual average was 99 gallons/MWh if Dust Suppression was included, but only 0.7 gallons/MWh if it was excluded (Table 5). Not visible on the boxplot including Dust Suppression is a single solar PV plant with a 5-year weighted annual average of 233 gallons/MWh (plant ID S0241). The only water use reported by this outlier was Dust Suppression.

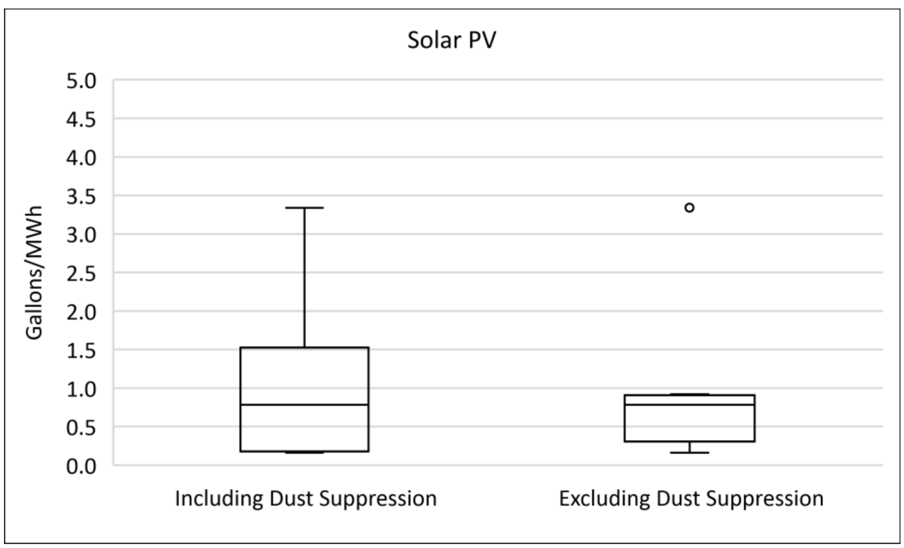

Figure 24. Box and whisker plot showing the 5-year weighted average annual consumptive water-intensities of solar PV plants. Not visible on the boxplot including Dust Suppression is a single solar PV plant with a 5-year weighted annual average of 233 gallons/MWh.

RESULTS: ESTIMATING POWER PLANT CONTRIBUTION TO REGIONAL WATER STRESS

A Recent Trend in Thermal Power Plant Water Consumption

The CEC power plant water consumption, and electricity generation data for California's thermal natural gas power plants (i.e. steam turbine and combined cycle) were compared over the 2011-2014 drought years (Table 6). Once-through cooled natural gas plants were excluded since they used ocean or brackish estuarine water for cooling. As the drought progressed, there was an increasing trend in both annual water consumption, and electricity generation from thermal natural gas plants. Hydroelectric generation decreased over the same years (Figure 4 and Table 1).

Table 6. California's annual thermal natural gas plant water consumption and electricity generation between 2011-2014.

Year	**Water Consumption (Billions of gallons)**	**Electricity Generation (Gigawatt-Hours)**
2011	13.9	52,500
2012	15.9	59,800
2013	17.9	80,500
2014	21.9	85,500

Average Water Consumption by Individual Power Plants

The 5-year average annual water consumption by 191 power plants located in California were mapped, categorized by generation technology, and laid over their respective planning areas (Figure 25). Refer back to the explanation for Figure 9 in the "California Department of Water Resources Water Plan data" Methods section for more details about the planning areas. For simplicity of display, a single air-cooled internal combustion engine natural gas plant (5-year average annual water consumption of 0.0003 thousand acre-feet/year) was left out. Power plants categorized as "Multiple" had a combination of combined cycle, steam turbine, or combustion gas (simple cycle) turbines.

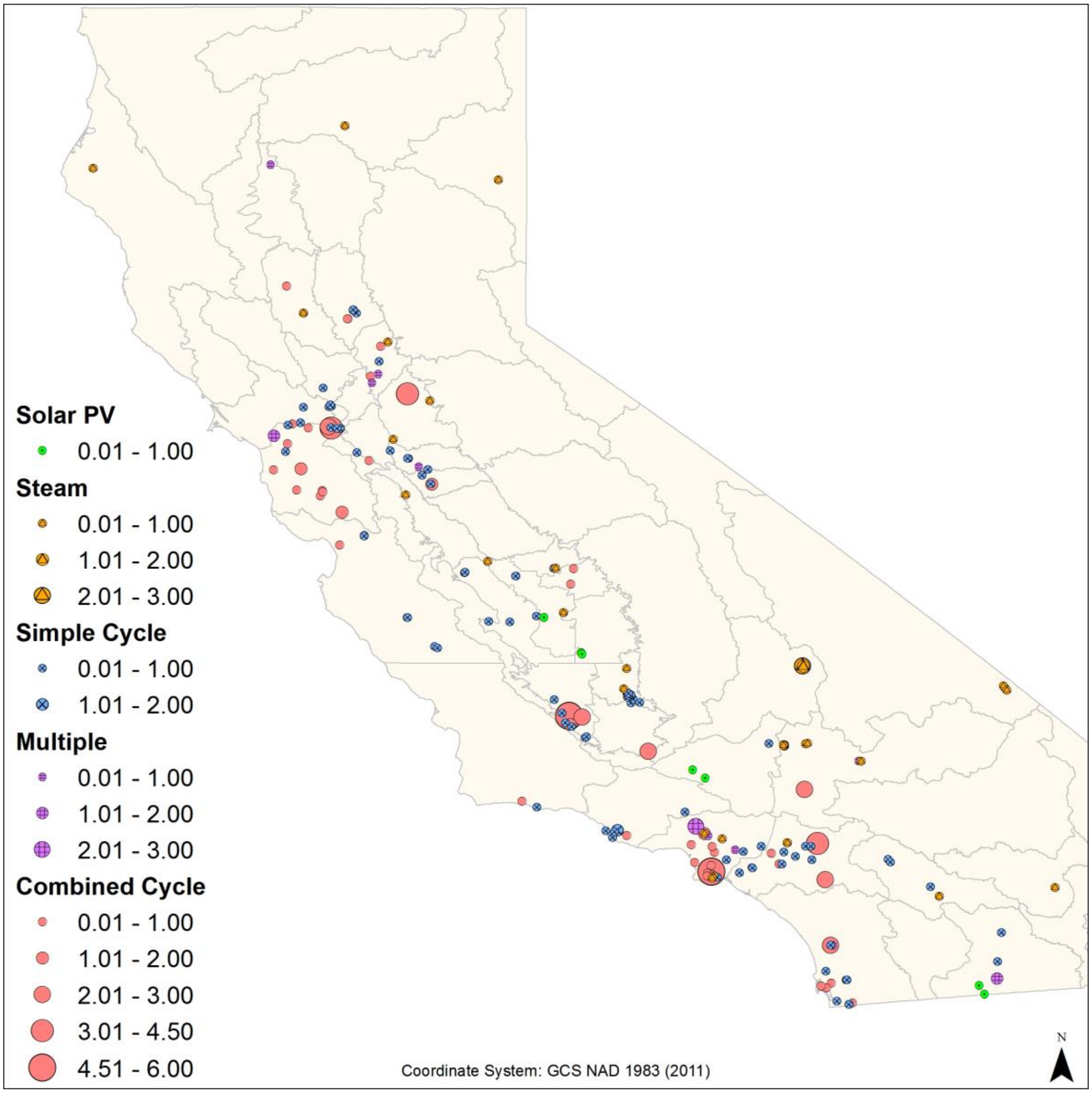

Figure 25. Five-year average water consumption (thousands of acre-feet/year) for 191 California power plants, categorized by generation technology, and laid over their respective planning areas. Planning area layer acquired from the CDWR (2013b).

California's Highest Consumption Power Plants

There were only 22 power plants with a 5-year average annual water consumption exceeding one thousand acre-feet/year. These power plants were listed by CEC plant ID, name, county location, water source, and generation technology (Table 7). The list is organized from lowest to highest 5-year average annual consumption. Seven of these plants relied on surface or potable water exclusively. The rest relied on recycled water, brackish groundwater, or a mixture of sources. Twenty of these 22 power plants were fueled by natural gas, the other two were cogenerating steam turbine coal plants. The majority of the natural gas plants were combined cycle.

Table 7. Water sources of the 22 power plants with a 5-year average annual water consumption exceeding 1,000 acre-feet/year. Units are thousands of acre-feet/year.

Plant ID	Power Plant Name	County	5-Year Average Annual Consumption	Water Source	Generation Technology
G0329	Magnolia	Los Angeles	1.04	Recycled	Combined Cycle Natural Gas
G0900	Walnut Energy Center	Stanislaus	1.20	Recycled	Combined Cycle Natural Gas
G0794	Metcalf Energy Center	Santa Clara	1.42	Recycled	Combined Cycle Natural Gas
G0935	Russell City Energy Company	Alameda	1.46	Recycled	Combined Cycle Natural Gas
G0190	El Centro Generation Station	Imperial	1.58	Surface	Multiple Generation Technologies Natural Gas
G0104	Chevron Richmond Refinery Cogeneration	Contra Costa	1.67	Recycled and Potable	Multiple Generation

Plant ID	Power Plant Name	County	5-Year Average Annual Consumption	Water Source	Generation Technology
					Technologies Natural Gas
C0001	ACE Cogeneration (Retired)	San Bernardino	1.77	Brackish Groundwater	Steam Turbine Coal
G0784	Sunrise Power	Kern	1.78	Surface	Combined Cycle Natural Gas
G0468	The Procter & Gamble Paper Products Co.	Ventura	1.94	Potable	Combustion Natural Gas (Simple Cycle)
G0861	Palomar Energy Center	San Diego	2.33	Recycled	Combined Cycle Natural Gas
G0648	Valley Generation Station	Los Angeles	2.43	Recycled	Multiple Generation Technologies Natural Gas
G0780	Los Medanos Energy Center	Contra Costa	2.50	Recycled	Combined Cycle Natural Gas
G0868	Inland Empire Energy Center	Riverside	2.64	Recycled	Combined Single Shaft Natural Gas
G0778	High Desert Power Project	San Bernardino	2.67	Recycled and Groundwater	Combined Cycle Natural Gas
C0017	Argus Cogen Plant	San Bernardino	2.79	Brackish Groundwater	Steam Turbine Coal
G0799	Elk Hills Power	Kern	2.89	Surface	Combined Cycle Natural Gas
G0797	Pastoria Energy Facility	Kern	2.97	Surface	Combined Cycle Natural Gas
G0889	Consumnes Power Plant	Sacramento	3.38	Surface	Combined Cycle Natural Gas
G0783	Delta Energy Center	Contra Costa	3.94	Recycled	Combined Cycle Natural Gas
G0795	Mountainview Generating Station	San Bernardino	4.12	Recycled and Brackish Groundwater	Combined Single Shaft Natural Gas
G0781	La Paloma Generating Co.	Kern	4.70	Surface	Combined Single Shaft Natural Gas

Plant ID	Power Plant Name	County	5-Year Average Annual Consumption	Water Source	Generation Technology
G0035	Watson Cogeneration Co.	Los Angeles	5.78	Recycled, Potable, and Groundwater	Combined Cycle Natural Gas

Average Water-Intensity by Individual Power Plants

The same 191 power plants were then mapped with the power plant's water consumption volume weighted by its electricity generation (i.e. the 5-year weighted average annual water-intensity) (Figure 26). When looked at by water volume (Figure 25), many of the steam turbine power plants had relatively low consumption. However, when looked at by water-intensity (Figure 26) steam turbine plants were amongst the highest intensity plants because they generated relatively little electricity compared to the volume of water consumed. A similar trend was evident with some of the combustion gas (simple cycle), combined cycle, and multiple generation technology power plants. In contrast, most of the highest consumption combined cycle power plants (Figure 25) had relatively low water-intensities (Figure 26) because they generated large amounts of electricity compared to the volume of water consumed.

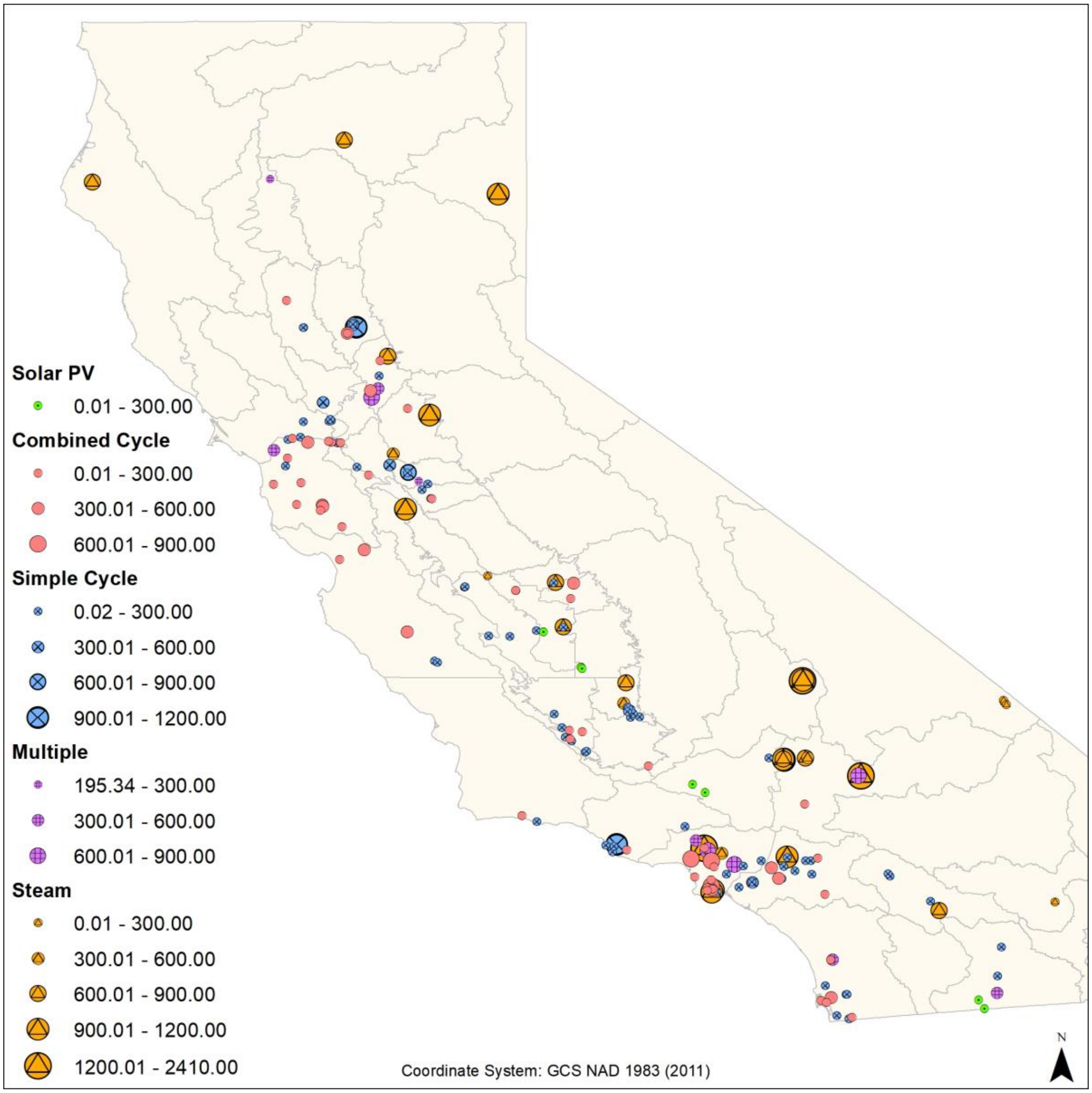

Figure 26. Five-year weighted average water-intensity (gallons/MWh) for 191 California power plants, categorized by generation technology, and laid over their respective planning areas. Planning area layer acquired from the CDWR (2013b).

California's Highest Water-Intensity Power Plants

There were only 22 power plants with 5-year weighted average annual water-intensities exceeding 800 gallons/MWh. These power plants were listed by CEC plant ID, name, county location, water source, and generation technology (Table 8). The list is organized from lowest to highest water-intensity. The majority had steam turbines. Three power plants (ACE Cogeneration [C0001], Argus Cogen [C0017], and The Procter & Gamble Paper Products Company [G0468]) were listed amongst both the highest water consumption (Table 7), and highest water-intensity (Table 8) power plants. However, according to the CEC QFER database, ACE Cogeneration has since been retired (CEC, 2016e).

Table 8. Water sources of the 22 power plants with a 5-year weighted average annual water-intensity consumption exceeding 800 gallons/MWh. Units are gallons/MWh.

Plant ID	**Power Plant Name**	**County**	**5-Year Weighted Average Annual Water-Intensity**	**Water Source**	**Generation Technology**
G0763	UCLA Energy Systems Facility	Los Angeles	802	Potable	Combined Cycle Natural Gas
E0005	Burney Forest Products	Shasta	805	Potable	Steam Turbine Biomass
G0767	Coolwater Generating Station	San Bernardino	838	Groundwater	Multiple Generation Technologies Natural Gas
G0758	Civic Center Cogen	Los Angeles	868	Unspecified	Combined Cycle Natural Gas
S0075	SEGS VI	San Bernardino	895	Groundwater	Steam Turbine Solar Thermal
E0098	Rio Bravo Fresno	Fresno	899	Groundwater	Steam Turbine Biomass

Plant ID	Power Plant Name	County	5-Year Weighted Average Annual Water-Intensity	Water Source	Generation Technology
E0112	Southeast Resource Recovery	Los Angeles	908	Potable	Steam Turbine Biomass
E0201	Buena Vista Biomass	Amador	908	Surface	Steam Turbine Biomass
C0001	ACE Cogeneration (Retired)	San Bernardino	910	Brackish Groundwater	Steam Turbine Coal
E0150	Stanislaus Resource Recovery Center	Stanislaus	922	Groundwater	Steam Turbine Biomass
S0076	SEGS VII	San Bernardino	922	Groundwater	Steam Turbine Solar Thermal
G0917	Feather River Energy Center	Sutter	942	Potable	Combustion Natural Gas (Simple Cycle)
G0201	Etiwanda Generating Station	San Bernardino	960	Recycled	Steam Turbine Natural Gas
S0072	SEGS IV	San Bernardino	1,014	Groundwater	Steam Turbine Solar Thermal
E0041	HL Power Company (Honey Lake)	Lassen	1,082	Groundwater	Steam Turbine Biomass
S0074	SEGS V	San Bernardino	1,085	Groundwater	Steam Turbine Solar Thermal
G0468	The Procter & Gamble Paper Products Co.	Ventura	1,102	Potable	Combustion Natural Gas (Simple Cycle)
C0002	Los Angeles Refinery - Calciner	Los Angeles	1,118	Potable	Steam Turbine Coal
S0071	SEGS III	San Bernardino	1,199	Groundwater	Steam Turbine Solar Thermal
S0070	SEGS II	San Bernardino	1,771	Groundwater	Steam Turbine Solar Thermal
G0410	Olive	Los Angeles	2,151	Recycled	Steam Turbine Natural Gas
C0017	Argus Cogen Plant	San Bernardino	2,407	Brackish Groundwater	Steam Turbine Coal

Aggregate Power Plant Contribution to Regional Water Stress

The ratio of 5-year average annual power plant water consumption to average human water demands (agricultural and urban consumption) was mapped, expressed as a percentage (Figure 27). In all but two planning areas, power plants consumed less than two percent of human water demands. Power plants only consumed more than two percent of human water demands in planning areas 902 and 905 (both located in the southeastern part of the state). This conclusion held true even when sensitivity tests were conducted to maximize the potential power plant contribution to regional water stress by substituting the average power plant consumption for the highest water consumption year for each power plant (not shown), and substituting the average human water consumption for the year where human water consumption was at a minimum (also not shown). Three of the 22 highest water consumption plants (ACE Cogeneration [C0001], Argus Cogen [C0017], and High Desert Power Project [G0778]) identified in the previous section (Figure 25 and Table 7) were located in the two planning areas where power plants consumed more than two percent of human water demands. ACE Cogeneration has since been retired (CEC, 2016e).

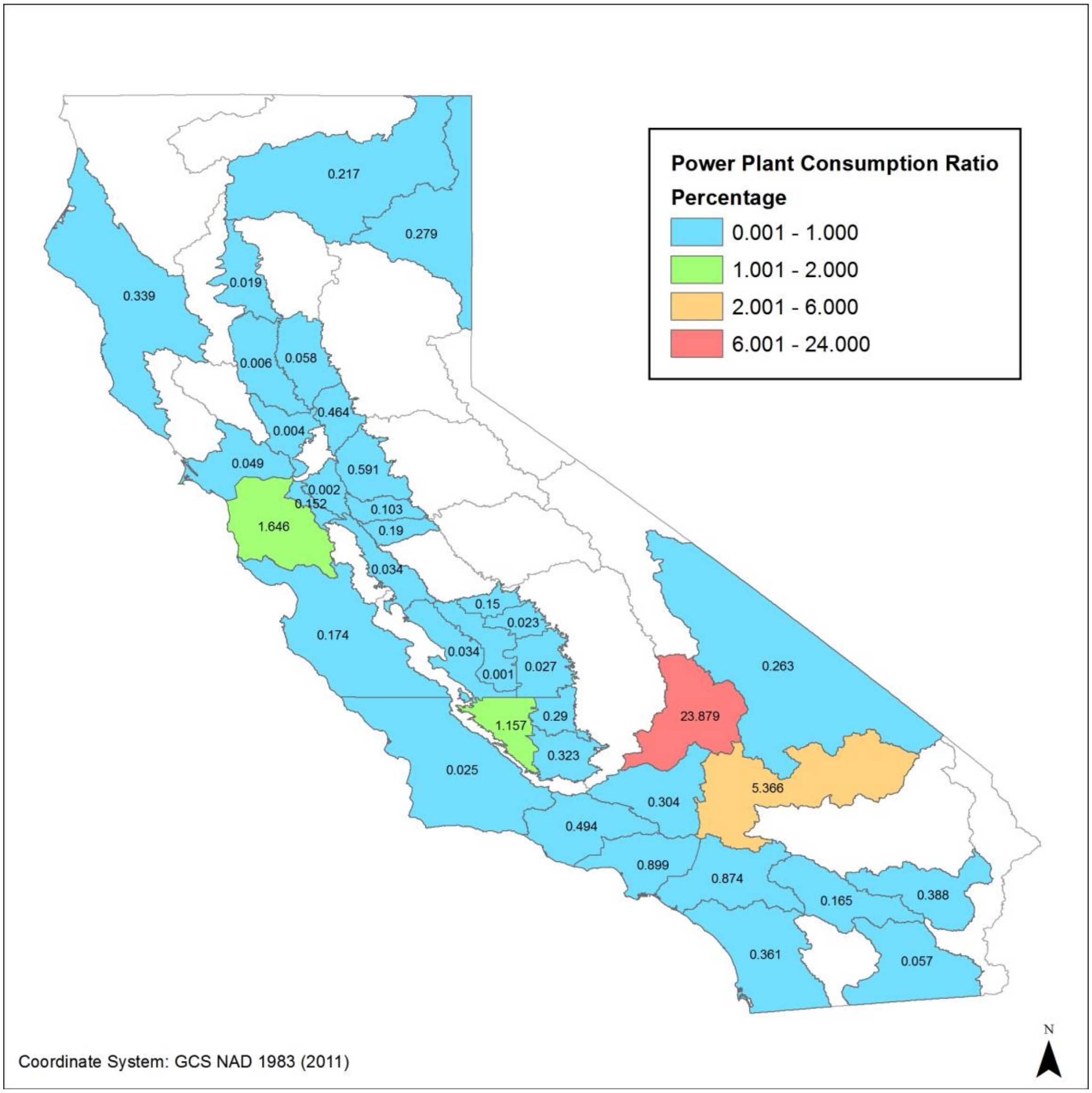

Figure 27. Ratio (expressed as a percentage) of the 5-year weighted average annual power plant consumption to average human water consumption for each planning area. Blank planning areas did not contain any power plants considered for this part of the analysis. Planning area layer acquired from the CDWR (2013b).

In planning area 902, two cogenerating coal plants (ACE Cogeneration [C0001], Argus Cogen [C0017]) consumed nearly 24 percent of average human water demands, and a potential maximum of 28 percent. Both of these coal plants consumed brackish groundwater for their primary water source. Argus Cogen was responsible for about 60 percent of the power plant water demand, and ACE Cogeneration for the other 40 percent.

In planning area 905, 10 power plants (eight solar thermal and two natural gas) consumed slightly over five percent of average human water demands, and a potential maximum of seven percent. All eight solar thermal plants consumed non-brackish groundwater as their primary water source. Both natural gas plants also consumed non-brackish groundwater, but one also consumed recycled water. One of the natural gas plants (High Desert Power Project [G0778]) was listed amongst the highest water consumption plants (Table 7). The other natural gas plant (Coolwater Generating Station [G0767]) and six of the solar thermal plants were amongst the highest water-intensity plants (Table 8). High Desert Power Project was responsible for about 47 percent of the power plant demand, the eight solar thermal plants combined for 40 percent, and Coolwater Generating Station for the remaining 13 percent.

RESULTS: IDENTIFYING POWER PLANTS LOCATED IN REGIONS OF HIGH WATER STRESS

Regional Water-Stress Ratio

The ratio of 1998-2010 average human water demand (agricultural and urban consumption) to the average available water supply was mapped, expressed as a fraction (Figure 28). Many of the planning areas in the San Francisco Bay Area, Central Valley, and southern California consumed over 60 percent of the available water supply.

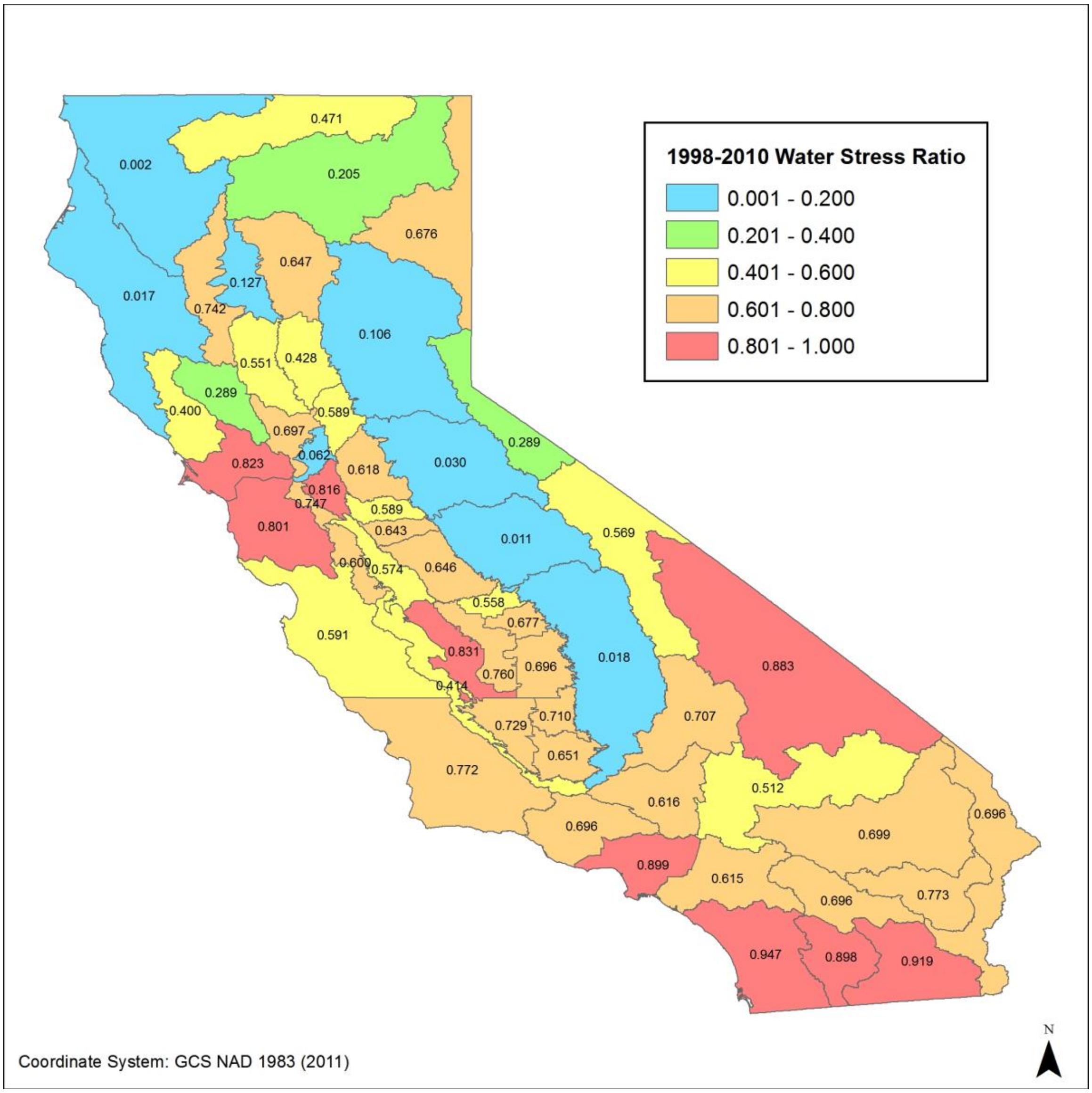

Figure 28. Ratio (expressed as a fraction) of 1998-2010 average human water consumption to the available water supply for each planning area. Planning area layer acquired from the CDWR (2013b).

The water stress ratio was sensitive to the water years chosen for comparison (Figure 29). Two particularly wet years (1998 and 2006), and two particularly dry years (2001 and 2007) were selected for comparison.

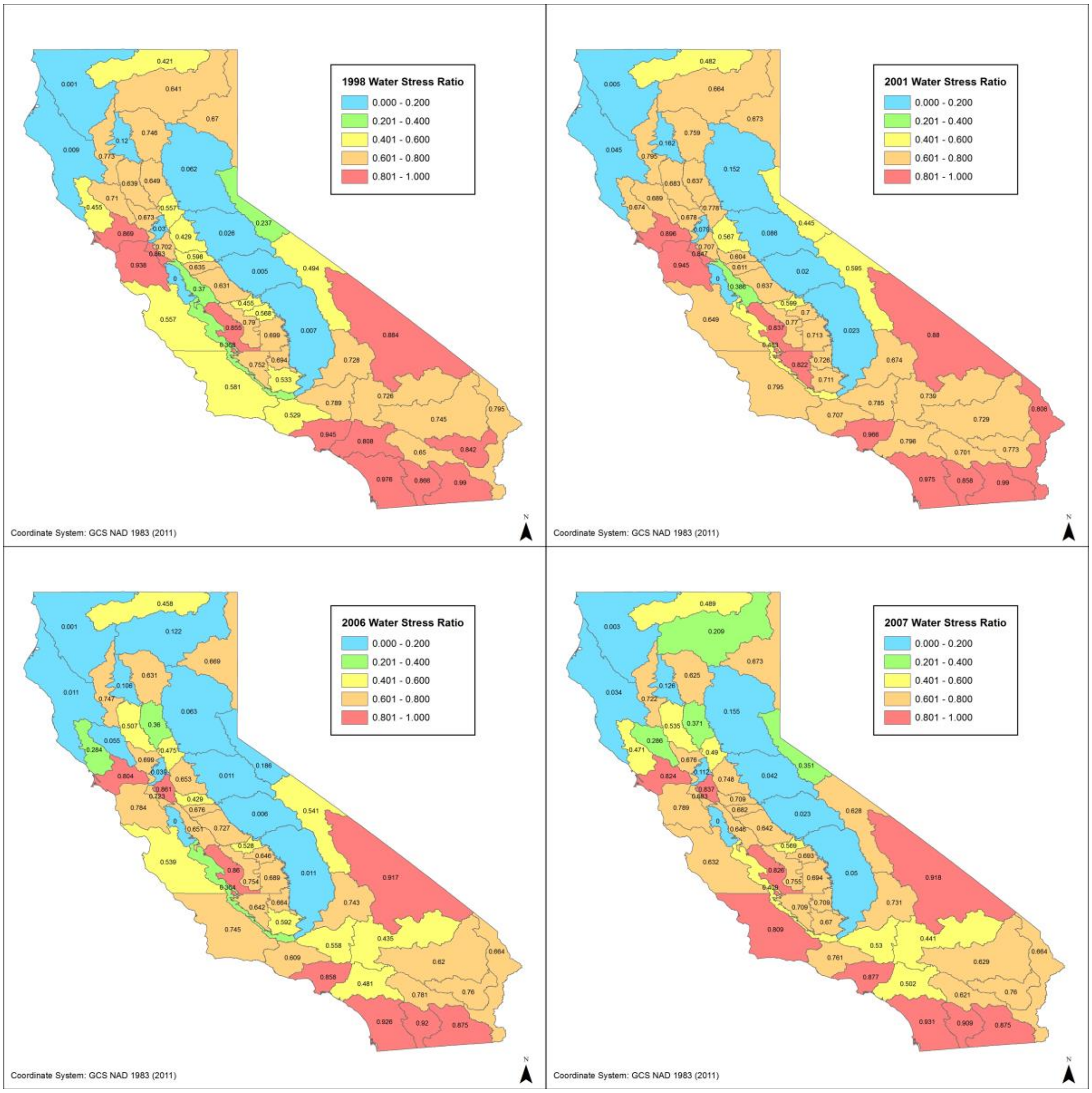

Figure 29. Ratio (expressed as a fraction) of the average human water consumption to the available water supply for each planning area for two wet years (1998 and 2006) and two dry years (2001 and 2007). Planning area layer acquired from the CDWR (2013b).

The water stress ratio was also sensitive to whether or not environmental water use was considered part of the available water supply (Figure 30). The level of apparent water stress increased throughout most of the state when environmental water use was excluded. Not including environmental water use produced unrealistically high, and misleading water stress ratios in planning areas, such as northern California, that are known to have the most abundant water supplies.

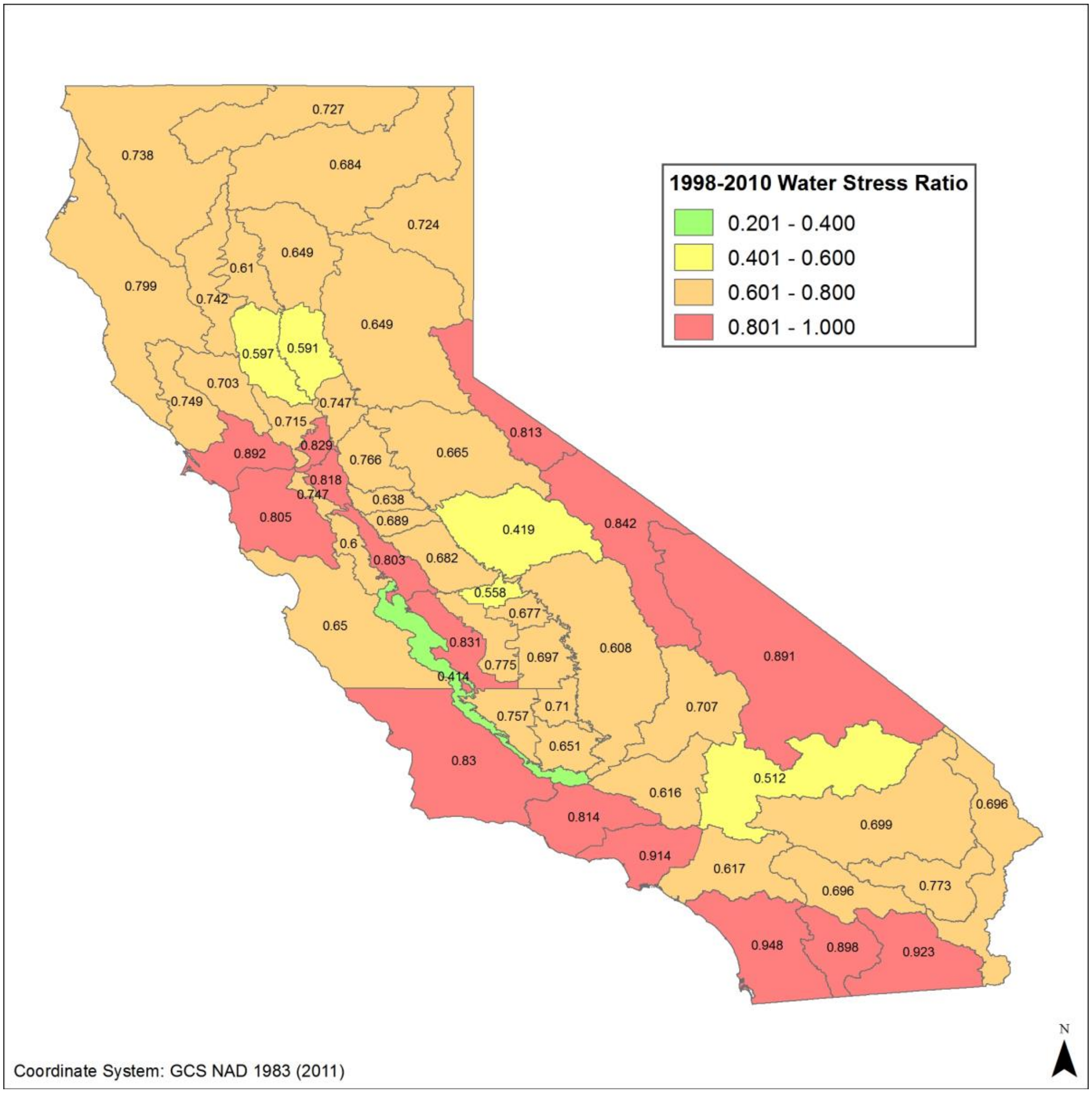

Figure 30. Water stress ratio (expressed as a fraction) when environmental water use was excluded from the available water supply. Planning area layer acquired from the CDWR (2013b).

Seven planning areas consistently showed high water stress (i.e. ratios above 80 percent), regardless of water year chosen (Figure 28 and Figure 29), or exclusion of environmental water use (Figure 30). Only six of these actually contained power plants.

These planning areas were located in the San Francisco Bay Area, Los Angeles Metropolitan Area, southern border (San Diego and Imperial counties), Mojave Desert, and one portion of the Central Valley.

Power Plants Located in Regions of High Water Stress

A total of 51 power plants were located in the six planning areas that consistently showed high water stress (Figure 31). Out of these, 24 consumed surface or potable water, seven non-brackish groundwater, eight unspecified sources, one brackish groundwater, and 11 recycled water or a mixture of sources.

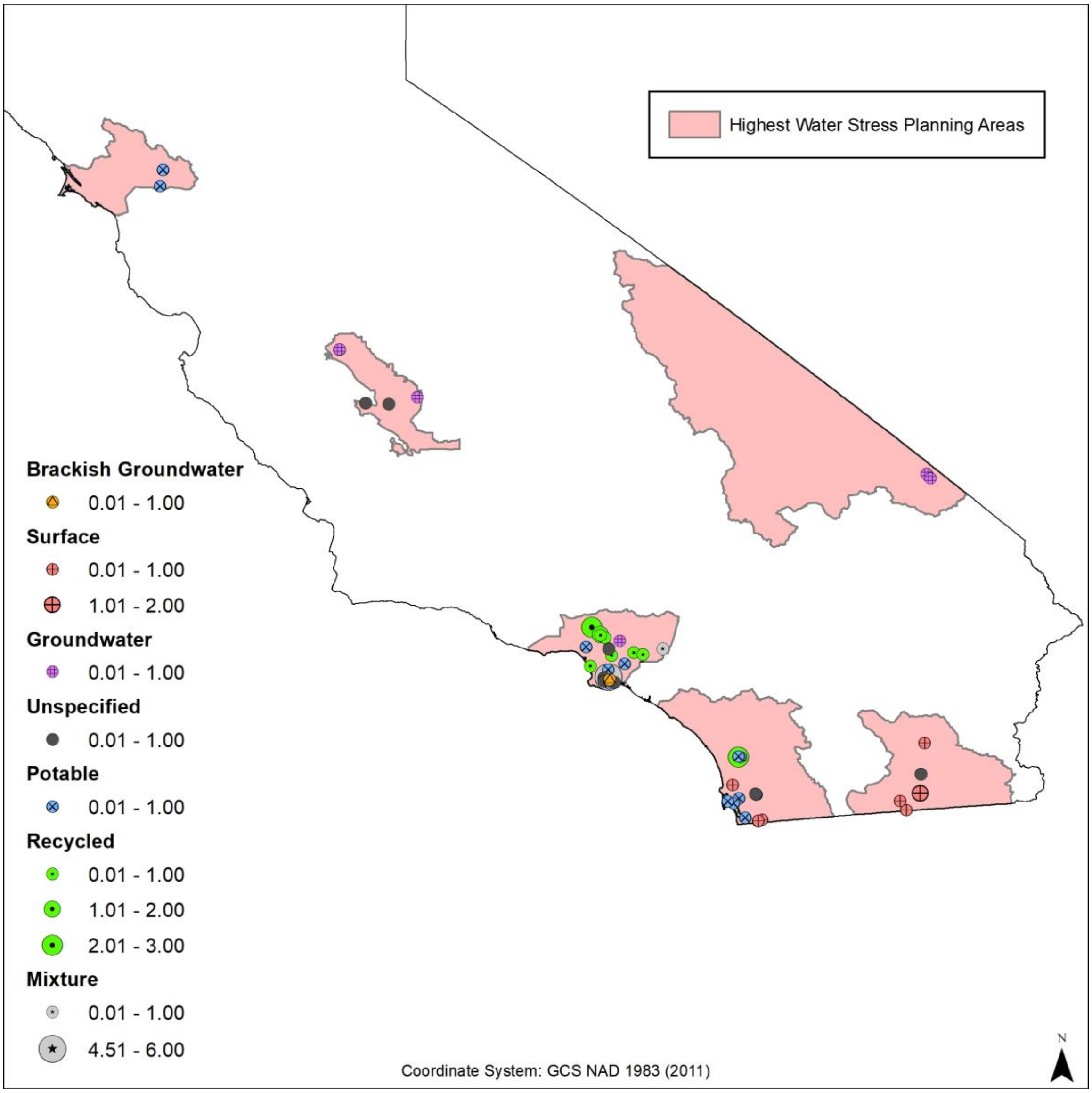

Figure 31. Water sources of the 51 power plants, displayed by 5-year average annual consumption (thousands of acre-feet/year) that were located in the six planning areas consistently showing high water stress. Planning area layer acquired from the CDWR (2013b).

The 39 power plants consuming surface, potable, non-brackish groundwater, or unspecified water sources were listed (Table 9). The 5-year weighted average annual water-intensity and 5-year average annual consumption volume of each power plant is also listed for comparison. One of the power plants (El Centro Generating Station [G0190]) was amongst the highest consumption power plants (Figure 25 and Table 7). Four of the power plants (Los Angeles Refinery [C0002], Southeast Resource Recovery [E0112], UCLA Energy Systems Facility [G0763], and Civic Center Cogen [G0758]) were amongst the highest water-intensity plants (Figure 26 and Table 8), and were all located in Los Angeles County.

Table 9. Water sources of the 39 power plants located in consistently high water stress regions that consumed surface, potable, non-brackish groundwater, or unspecified water sources.

Plant ID	Power Plant Name	County	Water Source	5-Year Weighted Average Annual Water-Intensity (Gallons/MWh)	5-Year Average Annual Consumption (Thousands of Acre-Feet/Year)
G0908	Panoche - Calpeak Power	Fresno	Potable	12	0.0004
G0906	Wellhead Power Gates	Fresno	Unspecified	58	0.0006
G0905	Wellhead Power Panoche	Fresno	Groundwater	65	0.0007
G0131	Coalinga Cogeneration	Fresno	Unspecified	93	0.09
G0997	Panoche Energy Center	Fresno	Groundwater	233	0.31
S0258	Campo Verde Solar Project	Imperial	Surface	0.2	0.0001
S0255	Imperial Solar Energy Center South	Imperial	Surface	0.2	0.0002
G0931	Niland Gas Turbine Plant	Imperial	Surface	12	0.002
G0504	Rockwood Gas Turbine Plant	Imperial	Unspecified	47	0.0003
G0190	El Centro Generating Station	Imperial	Surface	540	1.58
G0867	Henrietta Peaker	Kings	Groundwater	182	0.04
G0759	ConocoPhillips Los Angeles Refinery Wilmington Plant	Los Angeles	Unspecified	0.01	0.0000

Plant ID	Power Plant Name	County	Water Source	5-Year Weighted Average Annual Water-Intensity (Gallons/MWh)	5-Year Average Annual Consumption (Thousands of Acre-Feet/Year)
G0925	THUMS	Los Angeles	Unspecified	85	0.09
G9222	Riverside Energy Resource Center	Los Angeles	Potable	104	0.004
G0084	Carson Cogeneration Co.	Los Angeles	Potable	237	0.22
E0212	Total Energy Facilities	Los Angeles	Unspecified	265	0.13
G0246	Harbor Cogeneration Co.	Los Angeles	Surface	319	0.02
G0061	Broadway	Los Angeles	Groundwater	584	0.14
G0763	UCLA Energy Systems Facility	Los Angeles	Potable	802	0.66
G0758	Civic Center Cogen	Los Angeles	Unspecified	868	0.38
E0112	Southeast Resource Recovery	Los Angeles	Potable	908	0.70
C0002	Los Angeles Refinery - Calciner	Los Angeles	Potable	1,118	0.86
S0078	Ivanpah Unit 1 (Solar Partners II)	San Bernardino	Groundwater	18	0.009
S0080	Ivanpah Unit 3 (Solar Partners VIII)	San Bernardino	Groundwater	22	0.01
S0079	Ivanpah Unit 2 (Solar Partners I)	San Bernardino	Groundwater	29	0.01
G0924	Chula Vista Energy Center	San Diego	Potable	2	0.0000
G0910	Cuyamaca Peak Energy Plant	San Diego	Potable	3	0.0003
G0785	Otay Mesa Generating Project	San Diego	Surface	12	0.11
G0853	Border - CalPeak Power	San Diego	Potable	85	0.005
G0819	Larkspur Energy LLC	San Diego	Surface	92	0.02
G0845	Enterprise - CalPeak Power	San Diego	Potable	93	0.005
G0951	El Cajon Energy Center	San Diego	Unspecified	109	0.07
G1023	Miramar Energy Facility 1 & 2	San Diego	Surface	197	0.08
G0399	North Island Energy Facility	San Diego	Potable	213	0.21

Plant ID	Power Plant Name	County	Water Source	5-Year Weighted Average Annual Water-Intensity (Gallons/MWh)	5-Year Average Annual Consumption (Thousands of Acre-Feet/Year)
G0386	NTC MCRD Energy Facility	San Diego	Potable	264	0.14
G0626	Naval Station Energy Facility	San Diego	Potable	398	0.39
G0233	Goal Line	San Diego	Potable	411	0.24
G0902	Valero Cogeneration Unit #1	Solano	Potable	96	0.10
G0913	Wolfskill Energy Center	Solano	Potable	137	0.006

DISCUSSION: THE CONSUMPTIVE WATER-INTENSITY OF CALIFORNIA'S POWER PLANTS

Consumptive Water-Intensity Estimates

Not surprisingly, California power plants that were air-cooled, or non-thermal solar PV had the lowest weighted average consumptive water-intensities. Neither of these technologies require water for electricity generation. The average air-cooled plant had a weighted average consumptive water-intensity between 13-26 gallons/MWh (Table 5). The highest water-intensity air-cooled plant consumed an average of 107 gallons/MWh, but was clearly an outlier (Figure 20). This outlier was the only cogenerating air-cooled plant, and may be reporting its water use differently from the other air-cooled plants.

The consumptive water-intensity of solar PV plants depended on whether or not water used for Dust Suppression was included. Without Dust Suppression, solar PV plants had a weighted average consumptive water-intensity of 0.7 gallons/MWh (Table 5). Including Dust Suppression, the average increased to 99 gallons/MWh, due to an obvious outlier that had a weighted average consumptive water-intensity of 233 gallons/MWh (Table 5). Including dust suppression complicated matters because it is not water used directly for electricity generation. However, given the importance of keeping solar PV panels clear of dirt it was considered worthy of inclusion.

Combustion natural gas (simple cycle) plants had the third lowest consumptive water-intensity, followed by combined cycle natural gas plants. While combustion (simple cycle) power plants do not require water for electricity generation, they frequently use additional water for inlet air cooling or intercooling to improve the efficiency of generation. The average combustion natural gas (simple cycle) plant had a weighted average consumptive water-intensity of about 128 gallons/MWh, while the average combined cycle natural gas plant had a weighted average consumptive water-intensity of about 278 gallons/MWh (Table 5). The interquartile range (25th to 75th percentile) for combustion natural gas (simple cycle) plants was 40-182 gallons/MWh, and was 226-380 gallons/MWh for combined cycle natural gas plants (Figure 22). It makes sense that combined cycle plants would have a somewhat higher consumptive water-intensity than combustion (simple cycle) plants because combined cycle plants have a steam turbine that requires water for cooling, in addition to one or two combustion gas turbines.

Plants with only steam turbines, including once-through cooled plants, had the highest weighted average consumptive water-intensities, reflecting the dominant influence of Steam Cycle Cooling water use. On average, once-through cooled plants had a lower weighted average consumptive water-intensity (545 gallons/MWh [Table 5]), and interquartile range (616-1,284 gallons/MWh [Figure 21]) than the average non-once-through cooled steam turbine plant (1,734 gallons/MWh [Table 5], interquartile range 748-2,137 gallons/MWh [Figure 23]). However, if geothermal plants were excluded, then the average non-once-through cooled steam turbine plant had a consumptive water-intensity of about 897 gallons/MWh (Table 5), and much more similar interquartile range of 666-1,000 gallons/MWh (Figure 23). Bear in mind that the withdrawals water-intensity for once-through cooled power plants would have been orders of magnitude higher than the consumption results presented here. Recall that this study estimated that one percent of withdrawals by once-through cooled power plants is later consumed downstream (i.e. after the cooling water has been discharged to the environment) based on the best available, yet limited, literature estimates.

Geothermal power plants had the highest weighted average (2,035 gallons/MWh [Table 5]), and interquartile range (1,626-2,577 gallons/MWh [Figure 23]) of any steam turbine power plant category. Non-geothermal steam turbine plants (i.e. coal, natural gas, solar thermal, and wood biomass) had a smaller range of weighted average water-intensities (700-1,130 gallons/MWh [Table 5]), and interquartile ranges (635-1,555 gallons/MWh [Figure 23]).

Comparing this study's water-intensity results with recent literature

Comparing this study's consumptive water-intensity results to other recent studies was not totally straightforward because of differences in methodologies and technology categories used across studies. For example, this study calculated 5-year weighted annual averages, the CEC (2015b) used representative power plants to calculate presumably non-weighted averages, and Macknick (2012a) and Meldrum (2013) calculated median reported estimates. This study was unique in that it was carried out at the individual power plant scale with the water use and electricity generation reported to the CEC. This allowed annual water-intensity values to be calculated for each individual power plant, as well as overall 5-year weighted annual averages.

In general, this study's average water-intensity results agreed quite well with those of the CEC (2015b), Diehl (2014), Macknick (2012a), and Meldrum (2013) once outliers were removed. All studies tended to have a fairly narrow, similar range of water-intensity averages (or medians depending on the study) when similar technology categories were compared. The power plant technology categories showing the closest agreement between this study and other studies were air-cooled (combined cycle natural gas and solar thermal), combustion natural gas (simple cycle), combined cycle natural gas, steam turbine (natural gas and solar thermal, when assuming they had a wet-recirculating cooling system with cooling towers), once-through cooled nuclear, and solar PV (when Dust Suppression was excluded).

The results of this study were particularly close to those of the CEC (2015b), which makes sense given that this study relied upon the same data source. This study's water-intensity results had a tendency to be slightly lower than the CEC's (2015b) estimates, likely due to removing the reported Landscaping, and Sanitation and Drinking water codes, which the CEC may not have done.

This study differed most with the CEC's geothermal estimates. This study's average water-intensity was about 2,035 gallons/MWh, whereas the CEC's was 3,850 gallons/MWh. This study's average was at the lower end of the range reported by the CEC for geothermal power plants (2,000-5,700 gallons/MWh). The representative geothermal plants chosen by the CEC appear to have had higher water-intensities than the true range of water-intensities for all geothermal plants in California. The large difference in the minimum to maximum water-intensity ranges between this study (192-

4,170 gallons/MWh) and the CEC (2,000-5,700 gallons/MWh) lends support to that conclusion.

This study's results differed most significantly from Macknick (2012a) and Meldrum (2013) for the once-through cooled natural gas, and non-once-through cooled geothermal steam turbine categories. The once-through cooled natural gas results of this study were over twice that estimated in Macknick (2012a) and Meldrum (2013), likely due to methodological differences. The CEC did not provide any consumptive estimates for once-through cooled power plants, considering this to be negligible since California's once-through cooled power plants do not consume freshwater. In contrast, this author estimated that one percent of the water withdrawn by once-through cooled plants ends up consumed downstream (i.e. after the cooling water has been discharged to the environment) based on the best available, yet limited, literature estimates. Given that downstream consumption from once-through cooled power plants has been poorly studied, this is an area that warrants further investigation.

The geothermal results of this study were one or two orders of magnitude greater than those reported in Macknick (2012a) and Meldrum (2013). Methodological differences, along with the small number of source estimates used by these authors appears to explain the disparity. Macknick (2012a) and Meldrum (2013) both excluded estimates that included the use of onsite geothermal fluids, only considering the use of outside water sources. In contrast, the CEC data included the measured/estimated consumption (i.e. evaporation) of onsite geothermal fluids that were withdrawn from the geothermal reservoir, minus the geothermal fluids that were re-injected into the reservoir (Dennis, Christopher, personal communication, 2016).

DISCUSSION: POWER PLANTS CONTRIBUTING MOST TO REGIONAL WATER STRESS

A Recent Trend in Thermal Power Plant Water Consumption

As the drought progressed between the years 2011-2014, the electricity generation from thermal natural gas power plants continuously increased from 52,500 gigawatt-hours (GWh) to 85,500 GWh (Table 6). This coincided with the steady loss in hydroelectric generation over the same time period, which decreased from roughly 42,500 GWh to 14,000 GWh (Figure 4 and Table 1) as reservoir levels declined. Concurrently, the water consumption from thermal natural gas plants steadily increased from 13.9 billion gallons to 21.9 billion gallons. This drought trend is potentially problematic because thermal natural gas plants were forced to increase their water consumption, to make up for lost hydroelectric generation, at the same that the state's water supply was becoming increasingly scarce.

California's Highest Consumption Power Plants

Twenty-two of the 192 power plants analyzed in this study exceeded a 5-year average annual water consumption of 1,000 acre-feet/year. Seven relied on surface or potable water, and none on non-brackish groundwater. The rest of these 22 plants relied on recycled water, brackish groundwater, or a mixture of sources. Without considering how this consumption compares to other water demands or supplies in the area, then the power plants that relied on surface, potable, or non-brackish groundwater would be most likely to contribute to regional water stress during a drought. These seven power plants were displayed by name, and laid over the water stress map from Figure 28 (Figure 32). The El Centro Generating Station (G0190) was also located in a planning area that consistently experienced high water stress. This plant could potentially encounter water shortage that limits electricity generation during a drought, in addition to contributing significantly to regional water stress. Since six of these power plants are combined cycle (El Centro Generation Station also has a generator that is only steam turbine), they could avoid potential water stress issues by either upgrading the steam cycle portions of the power plant to an air-cooled system, or finding alternative water sources, such as recycled water. The seventh power plant (Procter & Gamble Paper Products Company [G0468]) is combustion gas (simple cycle) and may benefit from finding an alternative water source, or being replaced with solar PV or wind power.

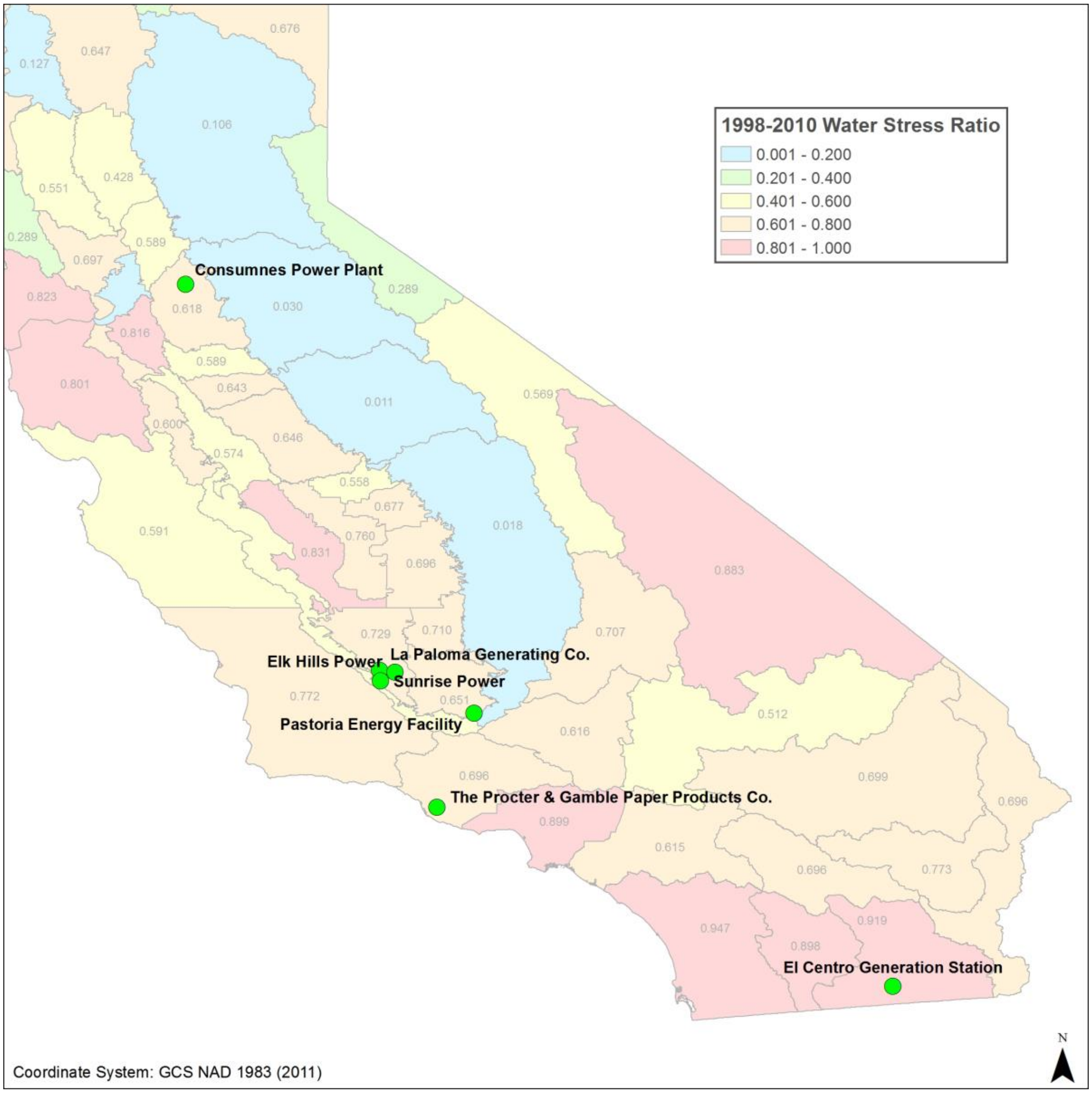

Figure 32. The seven highest water consumption power plants that consumed either surface or potable water. Planning area layer acquired from the CDWR (2013b).

California's Highest Water-Intensity Power Plants

Twenty-two of the 192 power plants analyzed in this study had 5-year weighted average annual consumptive water-intensities exceeding 800 gallons/MWh. Seventeen of these power plants consumed surface, potable, or non-brackish groundwater. One additional power plant (Civic Center Cogen [G0758]) did not report its water source to the CEC. The rest consumed recycled, or brackish groundwater. The 18 highest water-intensity power plants that consumed surface, potable, non-brackish groundwater, and unspecified sources would contribute disproportionately to regional water-scarcity because of their relative inefficiency at electricity generation. These 18 power plants were displayed by name, and laid over the water stress map from Figure 28 (Figure 33). Four of the power plants were located in a planning area that consistently experienced high water stress (Civic Center Cogen [G0758], UCLA Energy Systems Facility [G0763], Los Angeles Refinery – Calciner [C0002], and Southeast Resource Recovery [E0112]). Since 16 of these power plants have steam turbines (i.e. are combined cycle and/or only steam turbine) they could reduce their water-intensity by upgrading their cooling system to air-cooled, or finding alternative water sources, such as recycled water. The plants that are not yet combined cycle could also reduce their water-intensity by being upgraded to combined cycle configurations. The remaining two plants (Feather River Energy Center [G0917] and Procter & Gamble Paper Products Company [G0468]) are combustion gas (simple cycle) and may benefit from finding alternative water sources, or being replaced with solar PV or wind power.

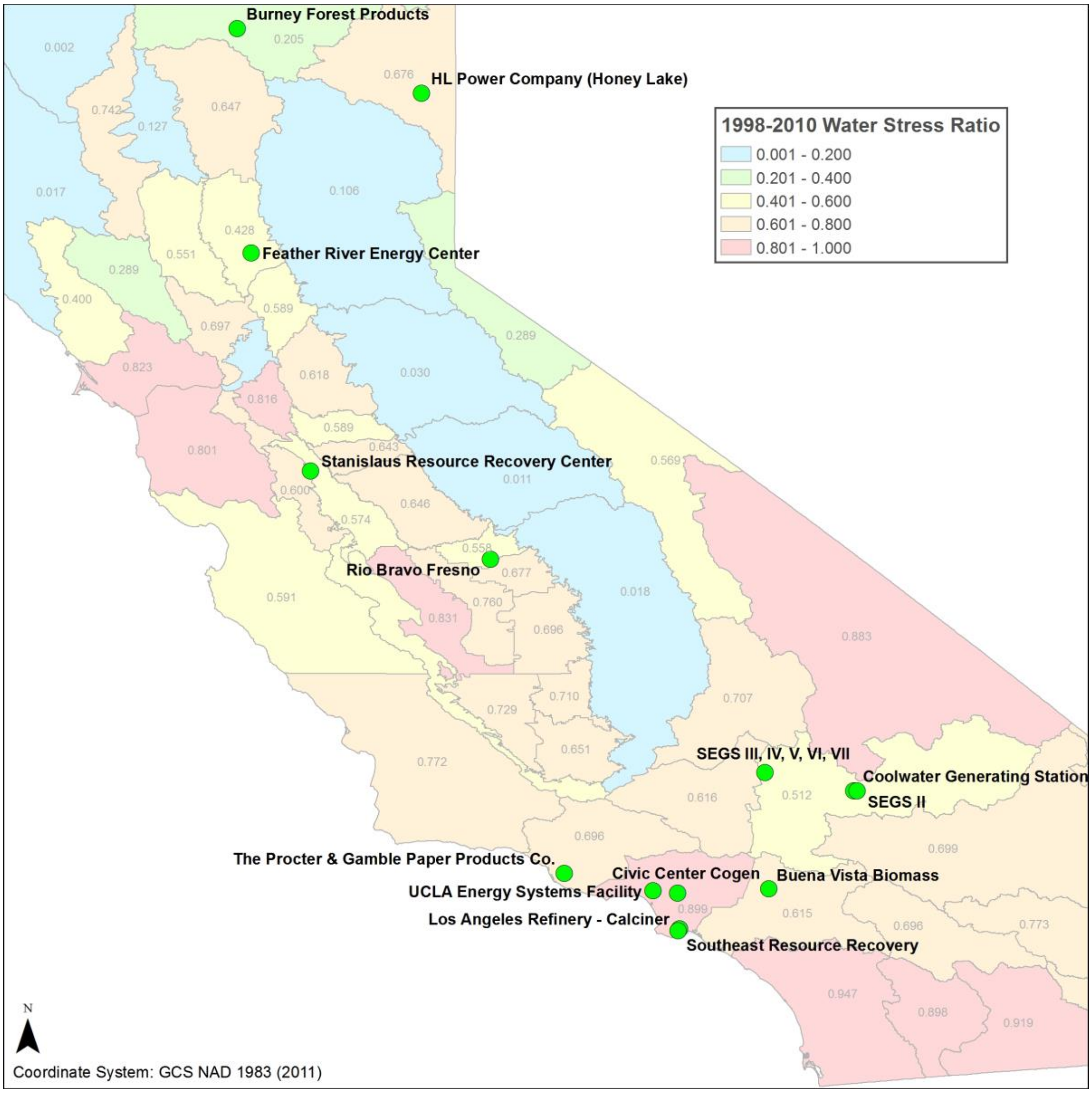

Figure 33. The 18 highest water-intensity power plants that consumed either surface, potable, non-brackish groundwater, or unspecified water sources. Note: SEGS III, IV, V, VI, and VII are all considered separate power plants. Planning area layer acquired from the CDWR (2013b).

Three power plants (ACE Cogeneration [C0001], Argus Cogen [C0017], and the Procter & Gamble Paper Products Company [G0468]) were listed amongst both the highest water consumption, and highest water-intensity power plants. The ACE Cogeneration plant has since been retired (CEC, 2016e). This is potentially problematic for the other two plants because they consume high volumes of water, and are also relatively inefficient at electricity generation. These three power plants were displayed by name, and laid over the water stress map from Figure 28 (Figure 34). The Procter & Gamble Paper Products Company (G0468) plant consumed potable water, while the other two consumed brackish groundwater. Solutions for the Procter and Gamble plant were offered in the previous two paragraphs. Argus Cogen (C0017) is a cogenerating coal-powered plant with only steam turbines. Further investigation would be needed to determine if power plants consuming brackish groundwater could potentially face competition for that water source, or if the brackish groundwater source might become limited during a drought. It is also worth investigating if the cooling systems can be upgraded to air-cooled to reduce the plant's water consumption. Retiring the aging coal plant and replacing it with solar PV, wind, or combustion gas (simple cycle) technologies would be other water saving options.

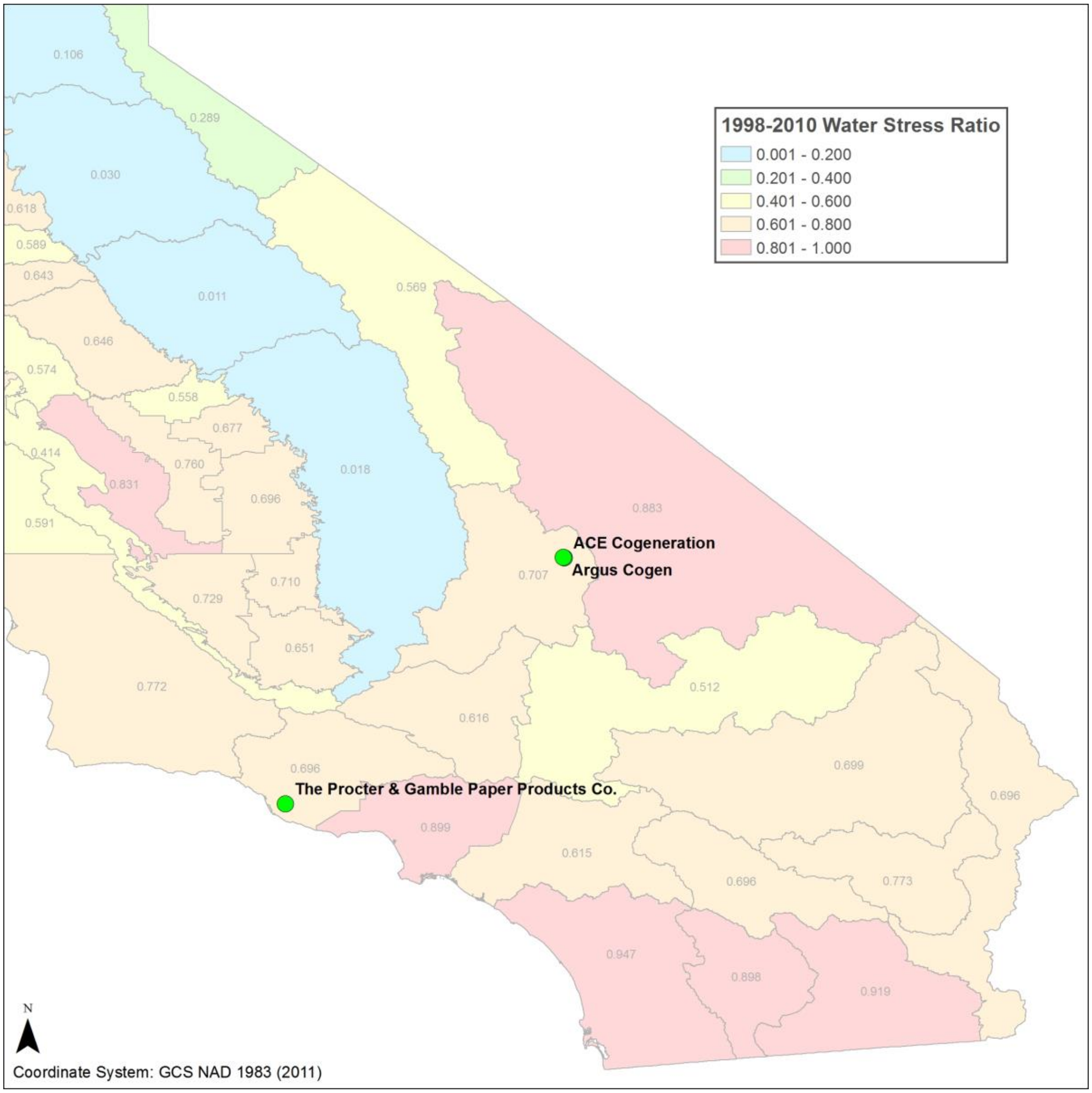

Figure 34. The three power plants that were both high water consumption and high water-intensity. ACE Cogeneration has since been retired. Planning area layer acquired from the CDWR (2013b).

Aggregate Power Plant Contribution to Regional Water Stress

In two planning areas (902 and 905), both located in the southeastern part of California, 12 power plants consumed more than two percent of the average human water demands in their respective planning areas. These 12 power plants were displayed by name, and laid over the water stress map from Figure 28 (Figure 35).

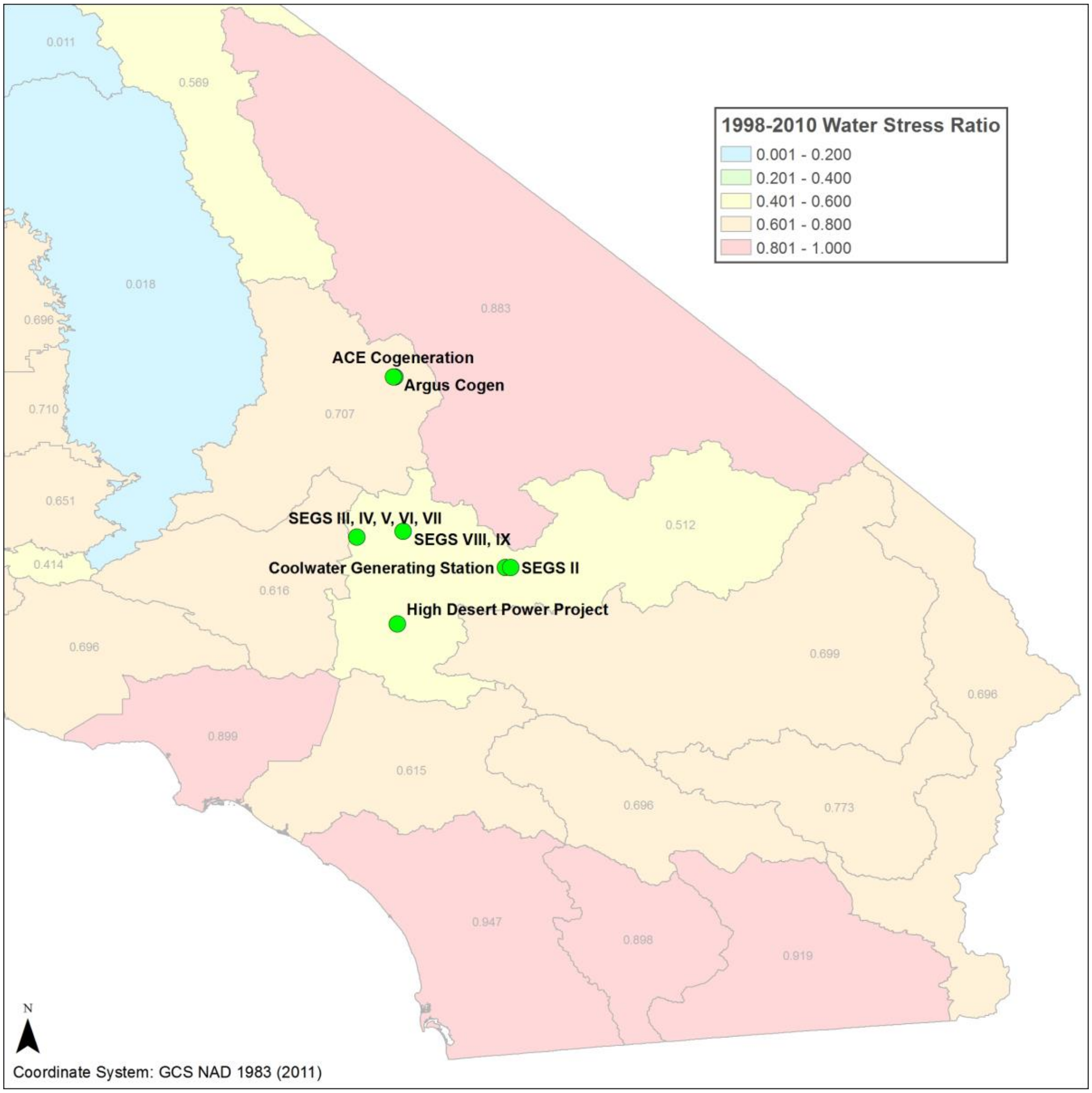

Figure 35. The 12 power plants located in planning areas where power plants contributed to more than two percent of the average human water demands. Note: SEGS III, IV, V, VI, VII, VIII, and IX are all considered separate power plants. Planning area layer acquired from the CDWR (2013b).

In planning area 902, two cogenerating coal plants consumed between 24-28 percent of the average human water demands. Argus Cogen (C0017) was responsible for about 60 percent of the power plant water demand, and ACE Cogeneration (C0001) for the other 40 percent. The ACE Cogeneration plant has since been retired (CEC, 2016e). Argus Cogen was amongst the 22 highest water consumption, and 22 highest water-intensity power plants. However, this plant relied on brackish groundwater, which needs further investigation to determine if it competes with other sectors for that water source, or if the brackish groundwater source might become limited during a drought. It is also worth investigating if the cooling systems of Argus Cogen's steam turbines can be upgraded to air-cooled. Retiring the aging coal plant and replacing it with solar PV, wind, or combustion gas (simple cycle) technologies would be other water saving options.

In planning area 905, eight solar thermal and two natural gas plants consumed between five to seven percent of the average human water demands. One of the natural gas plants (High Desert Power Project [G0778]) was listed amongst the 22 highest water consumption plants, while the other natural gas plant (Coolwater Generating Station [G0767]) and six of the solar thermal plants were listed amongst the highest water-intensity plants. High Desert Power Project was responsible for about 47 percent of the power plant demand, the eight solar thermal plants combined for 40 percent, and Coolwater Generating Station for the remaining 13 percent. These 10 power plants all relied on non-brackish groundwater (High Desert Power Project also used recycled), which could potentially become overdrawn and limited during a drought. Further analysis would be needed to determine the level of stress being placed on the groundwater resource by these 10 power plants and any other competing sectors. Since all of these power plants have steam turbines (i.e. are combined cycle and/or only steam turbine) they could benefit from upgrading their cooling system to air-cooled, or finding alternative water sources, such as recycled water.

Comparing this study's power plant contribution to water stress results with recent literature

These results were similar to those found by Averyt (2011) that California power plants generally contribute little to regional water stress. The results also confirm the observation that a single power plant, or cluster of power plants, have the potential to stress water supplies at a local scale (CEC, 2008; Averyt 2011; Averyt, 2013a). This study found that the two coal plants in planning area 902 (located in the southeastern part of California) potentially contributed quite significantly to the consumptive water demands of that region by consuming roughly 25 percent of those demands. Averyt (2011) did not find any areas of California where power plants contributed to more than "low" water stress (the exact definition of "low" was not clearly explained). However, this may be due to the fact that the results from Averyt (2011) were derived from water withdrawal data at the HUC-8 watershed scale, whereas this study used water consumption data at the CDWR planning area scale. This difference (i.e. water withdrawals versus consumption) prevents a direct comparison to Averyt's study.

DISCUSSION: POWER PLANTS LOCATED IN REGIONS OF HIGH WATER STRESS

Six planning areas, containing power plants located in the San Francisco Bay Area, Los Angeles Metropolitan Area, southern border (San Diego and Imperial counties), Mojave Desert, and one portion of the Central Valley, consistently had water stress ratios where human demands consumed over 80 percent of the available water supply. Although power plants consumed less than two percent of the human demands in all of these areas, they could still potentially be vulnerable to water stress due to the limited supply available for all competing sectors. A total of 51 power plants were located in these areas, 39 of which consumed surface, potable, non-brackish groundwater, or unspecified water sources. The power plants that did not specify their water source to the CEC cannot be properly assessed until their water sources are verified. One of the power plants (El Centro Generating Station [G0190]) was amongst the 22 highest consumption power plants. Four of the power plants (Los Angeles Refinery [C0002], Southeast Resource Recovery [E0112], UCLA Energy Systems Facility [G0763], and Civic Center Cogen [G0758]) were amongst the 22 highest water-intensity, and were all located in Los Angeles County. Generally, the 39 power plants that consumed surface, potable, non-brackish groundwater, or unspecified water sources can avoid potential water stress issues by upgrading their cooling systems to air-cooled, finding alternative water sources (e.g. recycled water), or being replaced with solar PV, wind, or combustion gas (simple cycle) technologies. Power plants that only have steam turbines could also upgrade to combined cycle configurations to lower their water-intensity.

DISCUSSION: POTENTIAL BIAS INTRODUCED FROM METHODOLOGY DECISIONS

Removing Water Uses Not Related to Electricity Generation

Out of the 11 power plants removed that only reported Landscaping, and Sanitation and Drinking water use, five were solar PV, and one was combustion gas (simple cycle), which could legitimately not need any water for electricity generation. Two combined cycle plants were removed, which should require water for cooling the steam cycle portion, unless they were only operating the combustion gas turbines. Three steam cycle plants were removed, which one might expect to need water for electricity generation. However, one of these steam plants was air-cooled, and should therefore require little, if any, water to generate electricity. The second steam plant was actually retired in 2007, and should not have been present in the dataset. The last steam plant should require water for cooling because it is not air-cooled. However, there were also other inconsistencies with the labeling at this particular facility, which raised questions about the accuracy of the reporting. This plant was initially mislabeled as plant ID G0805, but was later corrected to G0630.

Removing the Landscaping, and Sanitation and Drinking codes had little impact on the overall consumptive water-intensity trends because these water uses generally made up less than one percent of the reported water use (Figure 10 through Figure 19). The difference would have been most noticeable for solar PV, and air-cooled power plants since these types of plants had such small consumptive water-intensities.

Landscaping, and Sanitation and Drinking made up a relatively higher, but still minor, fraction of the water use at these types of power plants. If Landscaping, and Sanitation and Drinking had not been removed, then Solar PV and air-cooled power plants may have had slightly higher water-intensities.

Leaving the Other Water Code in Place

Three power plants with only steam turbines, and 11 combined cycle plants reported electricity generation from their steam turbines, but did not report the Steam Cycle Cooling water use code. This cannot be possible because none of these power plants were air-cooled. Instead, the Other Water code was reported for all, or the vast majority, of the water use (amounting to tens or hundreds of millions of gallons at times). This evidence points to a reporting error where the Other Water code was reported in place of the Steam Cycle Cooling code. Another possibility is that the power plants neglected to report the Steam Cycle Cooling water use altogether. If power plants were erroneously reporting Other Water in place of Steam Cycle Cooling, then removing the Other Water records would have led to an underestimate of the true water-intensity of electricity generation at some power plants. In contrast, leaving the Other Water records could have potentially led to an overestimate of the water-intensity at some power plants, but would have avoided accidentally removing water use related to Steam Cycle Cooling, which was by far the dominant reported water use by power plants with a steam cycle.

Removing Power Plants with Low Electricity Generation

Only five total years worth of data from four individual power plants had a gross electricity generation of less than 500 MWh. The reported generation in four of these years was five MWh or less, making it obvious that there was a data entry error, reporting error, or the water use was not related to electricity generation. The remaining year came from a combustion gas (simple cycle) power plant that only reported Nitrogen Dioxide Control water, which had an electricity generation of slightly over 130 MWh. The water-intensity of this power plant would have been 3,217 gallons/MWh for the year, which is very unlikely to be accurate considering the results of this study and recent literature.

Removing Apparent Water Use Code Reporting Errors

After scrutinizing the initial annual water-intensity results, years with identified water use code reporting errors were removed before re-calculating the final consumptive water-intensity estimates. Most power plants had consistent patterns of reported water use codes, which made it easy to identify single years where a code was either omitted, or an extra code added. Such errors generally caused a large change in the year's water-intensity result, relative to other years. There could be a small chance that the water use code was accurate, in which case removing the data would have biased the 5-year weighted average annual water-intensity result for an individual power plant. However, this would have had minimal impact on the overall consumptive water-intensity results and trends.

In cases where the reported water use codes (and annual water-intensities), from a power plant's most recent two or three years, differed significantly from the previous two or three years, the most recent time period was used for calculating the weighted average water-intensity. This decision introduced a higher amount of uncertainty into the results than when inconsistencies occurred for a single year of data. However, this seemed like the best decision given that the most recent years of data had been checked more thoroughly by the CEC (Dennis, Christopher, personal communication, 2016). It also reflected the most current state of water use at the power plant, assuming that the reporting in the most recent two or three years was accurate, because power plants may change over time. They could have had additions, upgrades, or modifications to the installed or operated generation technology, and cooling system.

Six power plants were completely removed for having interannual variations of two or more orders of magnitude, giving a strong suspicion that there were data entry or water use code reporting errors. One of these power plants was once-through cooled with a weighted average consumptive water-intensity of 26,025 gallon/MWh. Such an extreme consumptive water-intensity could not possibly be accurate. The other five power plants had average water-intensities within the ranges of similar power plants, meaning that their removal produced little change to the overall consumptive water-intensity results. Adding the five power plants back in only produced a 20 gallon/MWh increase to the upper interquartile range of combustion gas (simple cycle) plants, but no impact to the overall water-intensity trends found in the results.

DISCUSSION: SOURCES OF UNCERTAINTY IN THE POWER PLANTS WATER USE DATA

A number of issues added uncertainty to the water-intensity results. As noted in the Methods section, the data was checked extensively for errors, and correcting errors in the data was an iterative back-and-forth process with the CEC throughout the study. Calculating the annual power plant water-intensity values was extremely helpful in identifying errors in the data. Many data entry errors were fixed, but it is possible that some mistakes went unnoticed. Water use code reporting errors, on the other hand, were sometimes confirmed by the CEC, but could not be corrected due to time constraints. Such reporting errors were removed from the analysis.

Although the CEC makes efforts to validate the reported data, they have lacked the resources to detect and follow up on all sources of error, due to many other agency priorities (Dennis, Christopher, personal communication, 2016). The CEC has checked the data from more recent years more thoroughly than older years, and plants larger than 75 MW in nameplate capacity have been checked more thoroughly than plants between 20-75 MW (Dennis, Christopher, personal communication, 2016).

The following discusses factors that contributed to uncertainty in the data and results. The CEC power plants data suffered from many of the same reporting and data entry errors that were found in the EIA data by Averyt (2011; 2013b) and Diehl (2014).

Self-Reporting Errors by Power Plants

The primary source of uncertainty was caused by power plants self-reporting their monthly water use to the CEC. This introduced uncertainty into the data because power plants make mistakes. For example, power plants sometimes reported inaccurate water use codes, or other times made data entry errors when reporting. Data entry errors would at times throw off a year's water-intensity value by multiple orders of magnitude. Inaccurate reading or recording of onsite water meters (when a meter is present) can be another source of error (Dennis, Christopher, personal communication, 2016). Each individual reporting power plant had the potential to introduce error into the data.

A few types of water use code reporting errors were found. Some power plants appeared to be reporting the incorrect water use codes, unless the CEC's QFER database contains incorrect information about the plant's generation technology. Four steam turbine plants were discovered that did not report any Steam Cycle Cooling water use. This cannot be accurate because these plants were not air-cooled. Similarly, two combustion gas (simple cycle) power plants were discovered that reported Steam Cycle Cooling water use. This cannot be accurate because these plants did not have a steam turbine. Examples were also found where 11 combined cycle power plants reported electricity generation from their steam turbines in the QFER database, but never reported any Steam Cycle Cooling codes in the water use data. This cannot be possible because none of these plants were air-cooled. Five power plants that only had steam turbines were found to be reporting Inlet Air Cooling and/or Intercooling water use codes. These codes appeared to be in error because they were generally only reported by power plants with combustion gas turbines (simple or combined cycle).

Cases were encountered where power plants either omitted, or added, a particular code (e.g. Steam Cycle Cooling, Other Water, etc.) for only a single year, causing significant changes in the water-intensity calculation for that year, relative to other years. If the inconsistent reporting only happened in one year, then it was most likely a reporting error because plants generally had a consistent pattern of reported water use codes. The following sections discuss other possible reasons for the observed reporting inconsistencies that go beyond self-reporting errors.

Inconsistent Reporting

Some power plants had a consistent pattern of reported water use codes for two or three years that was suddenly replaced with a new pattern of codes for the remaining years. This often resulted in significant changes to the annual water-intensity. In these cases, the more recent period of time was used as this reflects the current state of water use at the plants in question. This choice was further justified by the fact that the data quality of the most recent years had been checked more thoroughly than older years (Dennis, Christopher, personal communication, 2016). However, determining if there was a reporting error over multiple years was less certain than when the inconsistency was only observed for a single year. For instance, the discrepancy could have been caused by power plants that suddenly started reporting new water use that previously went unreported (e.g. by mistake or lack of water meter) (Dennis, Christopher, personal communication, 2016). Such power plants may have also undergone additions, upgrades, or modifications to the installed or operated generation technology, or cooling system. Combined cycle plants could have been operating with or without the steam cycle if necessary (Poch, 2009). Combustion gas turbines, in simple or combined cycle configurations, could have been operating with or without inlet air cooling or intercooling if needed. None of these possibilities would be easy to determine from looking at the data alone.

Lack of Water Meters

Another source of uncertainty was that not all power plant generators had meters to measure their water use (Dennis, Christopher, personal communication, 2016). Even those that do have properly functioning, calibrated meters are only accurate to within ± 10 percent, depending on the model installed (Dennis, Christopher, personal communication, 2016). As a result, some power plants cannot measure certain water uses, but may have the means to provide estimates instead. Thus, when a power plant does not report any water use under a particular code, it does not necessarily mean that water was not used for that purpose.

Estimated Water Uses

Estimated water uses, in plants without meters, are better than no data at all, but also added an element of uncertainty to the data and results. There were countless, obvious examples of power plants estimating a particular water use code(s). These entries were apparent when the same exact value was reported for all months of a given year(s), or for particular months over multiple years. First, estimated entries are problematic because they make it impossible to detect any seasonal variation in water use that may exist. They give a false temporal consistency to the reported water use. Second, estimates added inaccuracy to the water-intensity results, especially when they caused the water consumption value to remain constant, while the electricity generation continued to vary from month to month. Third, the false consistency raises a concern that some power plants may be "cooking the books" because they can get away with it. For these reasons, the water-intensity values were calculated at an annual time period, rather than a monthly or seasonal period.

Data Entry Errors by the CEC

Another major source of error was introduced when the CEC re-organized the reported data for reports and other agency purposes (Dennis, Christopher, personal communication, 2016). Simply stated, the CEC also made numerous data entry mistakes that caused large changes in the annual water-intensity calculations. Many of these errors were fixed, but it seems unlikely that all were found.

The Ambiguous Other Water Code

The use of the ambiguous, catch-all Other Water code also added uncertainty to the data because it was not clear what water use this code refers to. In theory, the Other Water code should only be used to report non-cooling related water uses that do not fit in any other categories. However, this was evidently not always the case. There were three examples of power plants with only a steam turbine that reported all, or the vast majority, of the water use as Other Water, but none as Steam Cycle Cooling. This suggested that Steam Cycle Cooling water was probably embedded in the Other Water code for these plants. At least 11 combined cycle plants appeared to be making the same mistake because they reported electricity generation from their steam turbines, but did not report Steam Cycle Cooling water use. It is more difficult to determine when combined cycle plants are using the Other Water code inaccurately because they are capable of operating without their steam turbines, instead only running the combustion gas portions (Poch, 2009).

There is also a possibility that some of the cogenerating power plants use the Other Water code to report the steam sold to nearby facilities. Many, but not all, of the highest water-intensity combustion gas (simple cycle) plants employed cogeneration and reported large volumes of Other Water. The reporting by power plants that employ cogeneration may be inconsistent because there is a lack of guidance for these types of power plants in the CEC-1304 reporting form (CEC, n.d.).

At any rate, the uncertainty in the reporting of the Other Water code meant that this code was left in place for the water-intensity analysis. If the Other Water code did have Steam Cycle Cooling water use embedded (the dominant water use by plants with a steam turbine), then removing the Other Water code would have underestimated the water-intensity of some power plants. In contrast, leaving the Other Water code may have overestimated the water-intensity at some power plants, but this would have introduced less inaccuracy than removing the code.

Gaps in Cooling System Information

The CEC's QFER database does well at tracking changes in generation technologies (CEC, 2016e), but does not sufficiently track the installed cooling systems. This is surprising given that the CEC-1304 form (schedule 3, part A) requires power plants with a nameplate capacity of 20 MW or greater to report this information. As a result, comparing the generation technology against the reported water use codes was the best way to determine if the reported codes made sense or not. The CEC is well aware of all plants with once-through cooled generators in California (CEC, 2016a; CEC, 2016d) because they must be phased out by the year 2030. The agency does not confidently know all of the plants with air-cooled generators, unless they were licensed by the CEC (i.e. have a nameplate capacity of 50 MW or greater) (Dennis, Christopher, personal communication, 2016). However, one additional air-cooled power plant was discovered (plant ID G0838), with a nameplate capacity of 166 MW, when the CEC dataset was cross-referenced with data from the EIA (2016). It is uncertain if there were other air-cooled power plants that the CEC is not aware of. Power plants that were not known to be once-through or air-cooled were assumed to be wet-recirculating cooled, but better tracking of the cooling systems would have inspired more confidence.

Mismatch Between Generator ID Numbers

The results of this study were limited to the power plant level because there were too many instances where the generator ID numbers between the water use and electricity generation data did not match up correctly. Being able to carry out the analysis at the generator level would have simplified the characterization of water-intensity at power plants that had multiple generation technologies, cooling systems, and/or primary fuel types. Plants with multiple generation technologies did not fit easily into the generalized water-intensity results, and were therefore not included.

Electricity Generation Errors

Finally, there is a chance that the electricity generation data from the QFER database could contain errors that impacted the water-intensity results. The CEC believes that the reporting of electricity generation is much more accurate than the water use reporting because electricity generation is tied to power plant revenues (Dennis, Christopher, personal communication, 2016). If a power plant did not report any electricity generation for a given period, then that number can supposedly be trusted with a much higher degree of confidence. However, there were still a few instances where apparent electricity generation errors resulted in the large annual water-intensity variations encountered. There is no reason to believe that power plants, or the CEC, do not occasionally make errors when reporting, entering, or re-organizing the electricity generation data.

DISCUSSION: RECOMMENDATIONS FOR IMPROVING THE QUALITY OF THE REPORTED POWER PLANTS WATER USE DATA

As mentioned previously, calculating the annual water-intensity values at the power plant scale was extremely helpful in identifying inaccuracies in the reported data. Water use code reporting errors, and data entry mistakes can both be found with this technique. This worked because most power plants had a relatively consistent pattern of reported water use codes across years. Generators and/or power plants, at a given location, should have water-intensities that fall within a relatively consistent range, given the technologies installed (e.g. generation technology, cooling system, fuel type, etc.). If the CEC (and probably EIA, and comparable agencies in other states) wanted to improve the quality of reported power plant water use, then linking the water use and electricity generation data at an annual (or monthly) scale would be a critical first step for auditing the accuracy of the reported data.

Besides auditing the reported water use data by analyzing the annual water-intensity values, the following recommendations would also be helpful:

1. Track the currently installed technologies (especially cooling system and generation technology), and changes in the installed technologies over time to help make sense of sudden changes in water-intensity. Better tracking of the cooling systems, specifically improving the identification of wet-recirculating (making sure to distinguish between cooling tower and open pond systems) versus air-cooled generators would make it easier to understand when a power plant should be expected to report Steam Cycle Cooling water use codes. This would

also make it easier to identify power plants that could potentially be upgraded to an air-cooled system. However, tracking whether or not particular installed technologies are actually operating would be challenging and probably a limiting factor.

2. Match the water use codes with each individual generator, and track them over time, to allow auditors to identify when power plants may have forgotten to report a particular code, inadvertently reported an extra code, or reported the incorrect code. This idea fits with tracking the installed technologies because the pattern of reported water use codes would be expected to change when the installed and operating technologies change.
3. Prior to calculating annual water-intensity values, this author recommends removing water uses that are not directly impacted by the amount of electricity generated (e.g. landscaping, sanitation and drinking, dust suppression, and other miscellaneous uses). Including these types of water uses only serves to confound the understanding of the electricity generation-related water-intensity values. This is not to suggest that such water use data should not be collected, or that they are not important, but to argue that they detract from the water-intensity directly related to electricity generation.
4. In the most ideal scenario, install water meters on all power plant generators to eliminate gaps in water use data for plants that do not have meters, and which cannot provide estimates. This would also avoid the need for plants that do provide estimates to report unrealistic water use values that do not vary over time

with the amount of electricity generated. Estimated water uses caused an artificial consistency in the reported water use, which limited the accuracy of the calculated water-intensity results. If estimates must be used, then they should somehow be tied to the amount of electricity generated, and the method used should be documented and transparent.

5. Phase out the ambiguous Other Water code because it is not clear what water uses the power plants are reporting when they use it, or whether power plants are using the code correctly. At the very least, power plants should be required to explain what "other water" actually means in their reporting so that auditors can understand if the water use is directly related to electricity generation or not, or if it belongs under another water use code. At present, this code adds the most uncertainty to the water-intensity values.
6. Obtain the primary water source information from power plants that have not reported this information. Such information is crucial for properly assessing the drought risk of a power plant, and identifying plants that may need to be switched to alternative water sources.
7. Cogenerating power plants could probably use more guidance about whether or not to report the water use related to producing steam for nearby facilities. There may be an inconsistency in how cogenerating power plants report this water, with some reporting it as Other Water, and others not reporting it at all. Currently, it does not appear like there is any guidance about how cogenerating power plants should report their water use in the CEC-1304 form.

DISCUSSION: RECOMMENDATIONS FOR AVOIDING WATER STRESS ISSUES

Some general recommendations can be made to save water, and avoid potential water stress issues that might impact electricity generation in power plants identified as contributing disproportionately to regional water stress, or located in regions of high water stress.

1. Combined cycle power plants should look into upgrading their steam cycle turbines to air-cooled systems, or finding alternative water sources, such as recycled water. If small enough in nameplate capacity, then replacing them with solar PV or wind power could potentially be plausible.
2. Combustion gas (simple cycle) power plants should look into alternative water sources, or replacement with solar PV or wind power. These power plants tend to be small enough that replacing them with solar PV or wind power seems plausible. Also keep in mind the greenhouse gas reduction benefits of switching from natural gas to solar or wind.
3. Power plants that only have steam turbines should look into upgrading their cooling system to air-cooled, or finding alternative water sources. These power plants also have the opportunity to reduce their water-intensity by upgrading to combined cycle configurations. If small enough in nameplate capacity, then replacing them with solar PV or wind power could potentially be plausible.
4. Aging coal plants can potentially be retired, and replaced with solar PV, wind, or combustion gas (simple cycle) technologies. Replacing coal plants with

combined cycle natural gas plants would also likely achieve water savings, but to a lesser extent than the other options. Consideration of the relative greenhouse gas reduction benefits of switching to solar and wind versus natural gas is also important.

5. Determine the water sources of power plants that have not reported that information to the CEC to properly assess their water stress risk and determine if finding an alternative water source is warranted.

DISCUSSION: USGS THERMAL POWER PLANT WATER USE DATA FOR CALIFORNIA

Although the 2010 USGS report listed thermal power plant water withdrawal data for California, it does not paint a full picture. First, about 75 of the state's 100 largest non-once-through cooled thermal power plants were supplied by public water sources, and 50 of them used recycled water (CEC, 2015a). Neither of these water sources was included in the reported USGS figures (Maupin, 2014). Second, water consumption was not reported, even though all non-once-through cooled plants only report consumptive water uses to the CEC (Dennis, Christopher, personal communication, 2016). Third, USGS withdrawal information was aggregated at the county level, but a closer inspection revealed that half (29 out of 58) of California's counties did not report any thermal power plant water withdrawals (California Water Science Center, 2014). Contacting the USGS California Water Science Center (Brant, Justin, personal communication, July 2016), the USGS representatives responsible for validating California's thermal power plant data for the 2010 report, revealed that the methods from Diehl (2013; 2014) were used to estimate California's thermal power plant water withdrawals. This meant that the results were based on a list of about 150 California thermal power plants with a nameplate capacity of one MW or larger, located in about 36 counties (Diehl, 2014, Appendix). It is unclear then why only 29 counties, and not 36, had reported withdrawals for the final USGS report.

DISCUSSION: REASONS CALIFORNIA HAS NOT EXPERIENCED WATER-RELATED THERMAL POWER PLANT CURTAILMENT OR SHUT DOWN

After reviewing the scientific literature, California Independent System Operator (CAISO) seasonal assessment reports, and CEC EPR and IEPR publications, no examples could be found where water shortage or water temperature issues resulted in the curtailment or shutdown of California's thermal power plants, as has happened more commonly in the eastern half of the United States. Perhaps the risk of water shortage for California's thermal power plants is low, but it is not zero as demonstrated when the CAISO reported that four natural gas plants were at-risk of water shortage (Infrastructure Development, 2014; Infrastructure Development, 2015). This section seeks to understand why/how California has avoided water-related curtailment or shutdown of its thermal power plants by comparing California's thermal electricity generation landscape with curtailment trends in the eastern half of the country.

National Thermal Power Plant Curtailment Trends

When United States examples of thermal power plants being shut down or curtailed during drought and/or heat waves are examined (refer back to the Literature Review section titled "Impacts to Thermal Electricity Generation in the United States and Beyond"), it becomes clear that the majority of these examples have occurred in the eastern half of the country (Rogers, 2013). Second, curtailments or shutdowns have been due to either water temperatures becoming too high for effective cooling, water temperatures becoming too high to discharge within regulations, or water levels dropping below the power plant's cooling water intake pipe (Rogers, 2013). Third, all of the affected power plants were fueled by nuclear or coal power.

Considering the curtailment reasons, and geographic locations of these occurrences, it is probable that most, if not all, of the affected power plants were once-through cooled. Since once-through cooled plants require very high water withdrawals, they are mostly located in the eastern half of the United States where water is generally more plentiful (Averyt, 2011; GAO, 2015). According to Scanlon (2013b), problems with water quantity or discharge temperatures are mostly associated with once-through cooling, rather than wet-recirculating systems.

Reasons California is Different

California has most likely not experienced the types of electricity generation curtailments or shutdowns experienced in the eastern half of the country because there is a much higher fraction of electricity being generated from wet-recirculating cooling systems in the western United States, which withdraw much less water than once-through cooled systems (Averyt, 2011; GAO, 2015). Second, all of California's once-through cooled plants are located on the coast and use ocean or brackish estuarine water for cooling (CEC, 2008). The cold Pacific Ocean water temperature, and vast saline water supply for these once-through cooled plants seems unlikely to be seriously affected during a drought or heat wave.

Third, California has had a freshwater conservation policy since 1975, and updated in 2003 (State Water Resources Control Board, 1975; GAO, 2009; CEC, 2015b), that requires power plants to first consider alternative water sources for cooling, and to consider freshwater as a last resort only if the other methods would be "environmentally undesirable or economically unsound." The renewed 2003 policy also encourages power plants to consider air-cooled systems as another means of reducing freshwater use (GAO, 2009; CEC, 2015b).

Since the curtailment examples all involved nuclear or coal powered plants, it is worth noting that California only has one operational nuclear power plant, and California only generates a small fraction (1 percent or less) of its electricity from coal (Table 1). The nuclear plant is once-through cooled (CEC, 2016d), but is located on the coast. The use of ocean water makes the state's nuclear plant resistant to drought-induced water shortage. None of California's coal plants are once-through cooled (CEC, 2016d), which should also make them relatively drought-resistant because of lower withdrawal requirements.

CONCLUSION

Limited data availability and data quality issues have been barriers to understanding the water-intensity of thermal power plant operations in studies done by federal agencies (e.g. EIA and USGS), the CEC, and academics. California water-intensity studies have been limited to using literature estimates from prior studies, or to forming estimates based on representative power plants, due to the lack of available water use data for the state's power plants.

In an attempt to circumvent these issues, and improve the understanding of the water-intensity of electricity generation in California, power plant water use and electricity generation data, as reported to the CEC for years 2010-2014, was used to calculate the water-intensity of California's electricity generation infrastructure, at the power plant scale. Despite numerous uncertainties that may have impacted the water-intensity results (e.g. water use code reporting errors, data entry errors, inconsistent reporting, estimated water uses, the ambiguous Other Water code, and gaps in cooling system information), this study provides useful water-intensity estimates for the various power plant technology categories in California for which reported data was available. The biggest discrepancy between this study and others was in relation to the geothermal water-intensity estimates. This appeared to be primarily due to differences regarding the inclusion or exclusion of onsite geothermal fluids (Macknick, 2012a; Meldrum, 2013), and the choice of representative plants used to form the estimates (CEC, 2015b).

Numerous recommendations were made to improve the quality of the data. These recommendations could potentially be used by federal agencies, and possibly analogous agencies in other states, because the literature suggests that the types of problems found in this study are inherent in other Federal Government power plant datasets as well.

A list of power plants was identified that can be considered the most likely to contribute to regional water stress during a drought. A list of power plants was also identified that can be considered the most likely to be impacted by water stress during a drought. Water saving recommendations were made that would help these power plants avoid potential water stress issues.

More localized modeling efforts may be needed to determine the actual risks in regions where power plants were found to contribute most to water stress, and in regions where water stress appeared highest. Ideally, models would need to account for all competing demands, relative to the available surface and groundwater supplies, environmental water requirements, water rights priorities, and changes in supply/demand caused by seasonal/annual climate variation, particularly during the Summer and periods of drought.

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APPENDICES

Appendix A. The fraction of each water use code reported by once-through cooled plants.

Note: Water use reflects withdrawals in this table.

Water Use Code	Total Withdrawals (Millions of Gallons)	Percent of Total Withdrawals
Dust Suppression	20.3	0.0002
Generator Bearings	4,306.7	0.0524
Inlet Air Cooling	6.9	0.0001
Landscaping	6.8	0.0001
Other Cooling	866,604.4	10.5402
Other Water	12,428.9	0.1512
Steam Cycle Cooling	7,336,226.8	89.2280
Sanitation and Drinking	2,283.5	0.0278
Grand Total	***8,221,884.3***	

Appendix B. The fraction of each water use code reported by non-once-through cooled plants.

Note: Water use reflects consumption in this table.

Primary Fuel Type and Water Use Code	Total Consumption (Millions of Gallons)	Percent of Total Consumption
Biomass Total	***8,086.2***	
Inlet Air Cooling	364.4	4.5059
Intercooling	218.7	2.7047
Landscaping	0.5	0.0056
Other Cooling	51.3	0.6349
Other Water	319.2	3.9470
Steam Cycle Cooling	7,125.8	88.1242
Sanitation and Drinking	6.3	0.0776
Coal Total	***15,712.1***	
Intercooling	1,602.0	10.1957
Landscaping	10.7	0.0680
Other Water	4,756.1	30.2705
Plant Total	22.4	0.1428

Primary Fuel Type and Water Use Code	**Total Consumption (Millions of Gallons)**	**Percent of Total Consumption**
Steam Cycle Cooling	9,225.8	58.7175
Sanitation and Drinking	95.1	0.6054
Geothermal Total	***126,272.2***	
Intercooling	0.3	0.0003
Other Cooling	15,823.8	12.5315
Other Water	4,863.8	3.8518
Steam Cycle Cooling	105,577.6	83.6112
Sanitation and Drinking	6.7	0.0053
Natural Gas Total	***101,990.0***	
Boiler Makeup Water	79.4	0.0779
Dust Suppression	100.6	0.0986
Generator Bearings	2.6	0.0025
Inlet Air Cooling	4,853.8	4.7591
Intercooling	827.5	0.8113
Landscaping	231.5	0.2269
Nitrogen Dioxide Control	53.0	0.0520
Other Cooling	8,270.0	8.1087
Other Water	31,949.5	31.3261
Plant Total	2,347.3	2.3015
Steam Cycle Cooling	52,872.4	51.8408
Sanitation and Drinking	402.4	0.3945
Solar PV Total	***263.8***	
Dust Suppression	258.5	97.9872
Landscaping	1.9	0.7098
Other Water	0.4	0.1548
Panel Washing	0.3	0.1092
Sanitation and Drinking	2.7	1.0391
Solar Thermal Total	***2,537.2***	
Other Water	113.6	4.4772
Plant Total	14.9	0.5857
Steam Cycle Cooling	2,408.7	94.9372
Combustion Gas (Simple Cycle) Total	***7,599.1***	
Inlet Air Cooling	1,009.0	13.2775
Intercooling	489.4	6.4405
Landscaping	21.3	0.2800
Nitrogen Dioxide Control	19.4	0.2551

Primary Fuel Type and Water Use Code	**Total Consumption (Millions of Gallons)**	**Percent of Total Consumption**
Other Cooling	418.3	5.5040
Other Water	5,033.9	66.2435
Plant Total	531.1	6.9892
Steam Cycle Cooling	69.1	0.9096
Sanitation and Drinking	7.6	0.1005
Combined Cycle Total	***61,303.3***	
Boiler Makeup Water	79.5	0.1296
Inlet Air Cooling	3,524.9	5.7499
Intercooling	112.1	0.1829
Landscaping	41.4	0.0676
Nitrogen Dioxide Control	33.6	0.0548
Other Cooling	1,125.9	1.8367
Other Water	16,221.6	26.4612
Plant Total	1,737.0	2.8334
Steam Cycle Cooling	38,164.9	62.2558
Sanitation and Drinking	262.4	0.4280
Air-Cooled Total	***1,283.1***	
Inlet Air Cooling	28.6	2.2300
Landscaping	2.2	0.1676
Other Cooling	18.1	1.4127
Other Water	1,011.2	78.8130
Plant Total	14.9	1.1581
Steam Cycle Cooling	146.6	11.4269
Sanitation and Drinking	61.5	4.7917

Appendix C. The complete list of original power plants, including the reason for removal where applicable.

Note: Most information in this table, except water type, water source, and cooling system for air-cooled plants, can be found online in the QFER CEC-1304 Power Plant Owner Reporting Database. Power plants not specifically listed as once-through cooled or air-cooled are most likely wet-recirculating cooled, but this is not known with 100 percent certainty.

Plant ID	**Power Plant Name**	**Nameplate Capacity (MW)**	**Primary Fuel Type**	**Generation Technology**	**Reason Removed**	**Cooling System**	**Primary Water Type**	**Primary Water Source**
G1017	Sheraton San Diego East Tower	1.0	Natural Gas	Fuel Cell	Smaller than 20 MW in capacity		---	---
S0152	LA Harbor College	1.8	Solar PV	Photovoltaic	Smaller than 20 MW in capacity		---	---
G0054	Biola University	2.2	Natural Gas	Internal Combustion Engine	Smaller than 20 MW in capacity		---	---
G0225	General Mills Operations Inc Lodi Plant	3.4	Natural Gas	Combustion Gas	Smaller than 20 MW in capacity		---	---
G0494	Rhodia - Martinez	4.0	Other	Steam	Smaller than 20 MW in capacity		---	---
E0097	Blue Lake	13.8	Wood	Steam	Smaller than 20 MW in capacity		---	---
G0511	San Diego State University	14.3	Natural Gas	Combined	Smaller than 20 MW in capacity		---	---
T0063	Ormesa 1E	14.4	Geothermal	Steam	Smaller than 20 MW in capacity		---	---
T0066	Ormesa 1H	14.4	Geothermal	Steam	Smaller than 20 MW in capacity		---	---
T0022	GEM III	18.5	Geothermal	Steam	Smaller than 20 MW in capacity		---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
C0008	East Third Street Power Plant	19.0	Coal	Steam	Smaller than 20 MW in capacity		---	---
C0009	Loveridge Road Power Plant	19.0	Coal	Steam	Smaller than 20 MW in capacity		---	---
C0010	Wilbur East Power Plant	19.0	Coal	Steam	Smaller than 20 MW in capacity		---	---
C0011	Wilbur West Power Plant	19.0	Coal	Steam	Smaller than 20 MW in capacity		---	---
C0012	Nichols Road Power Plant	19.0	Coal	Steam	Smaller than 20 MW in capacity		---	---
S0127	Sun City	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		Other	City of Avenal
S0239	TA High Desert Antelope Power Plant	20.0	Solar PV	Photovoltaic			Potable	Lemoore Public Works
S0247	Alpaugh North LLC	20.0	Solar PV	Photovoltaic			Potable	Alpaugh Irrigation District
S0248	White River Solar LLC	20.0	Solar PV	Photovoltaic			Potable	Alpaugh Irrigation District
S0260	Kansas South	20.0	Solar PV	Photovoltaic			Potable	Lemoore Public Works
S0315	Kent South LLC	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		---	---
S0316	Old River One LLC	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		Groundwater	Well(s)
S0317	Corcoran Irrigation District Solar LLC	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
S0318	West Antelope Solar Park	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		---	---
S0319	Kansas LLC	20.0	Solar PV	Photovoltaic	Not metered, no water use reported		---	---
G0102	Cymric Cogeneration Plants	21.0	Natural Gas	Combustion Gas			Potable	West Kern Water District
S0111	Blythe 1 Solar	21.0	Solar PV	Photovoltaic	Did not report electricity generation related water uses		Groundwater	Well(s)
G0904	Fresno Cogeneration Partners LP Peaker	21.3	Natural Gas	Combustion Gas			Groundwater	Wells
T0005	Bear Canyon #2	22.0	Geothermal	Steam			Other	---
T0023	Aidlin #1	22.4	Geothermal	Steam			Other	---
T0062	Ormesa Geothermal I	22.4	Geothermal	Steam			Surface	Imperial Irrigation District
E0201	Buena Vista Biomass	22.5	Wood	Steam			Surface	Jackson Valley Irrigation District, Jackson Creek and Mokelumne River
G0758	Civic Center Cogen	23.0	Natural Gas	Combined but only Combustion Gas portion reported generation			---	---
C0007	Hanford	24.0	Coal	Steam			---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
E0150	Stanislaus Resource Recovery Facility	24.0	Municipal Solid Waste	Steam			Groundwater	---
T0043	Ormesa Geothermal II	24.0	Geothermal	Steam			Surface	Imperial Irrigation District
E0050	Madera Power	25.0	Wood	Steam	Two or more orders magnitude annual variation in water-intensity		Groundwater	Well(s)
S0180	McHenry Solar Plant	25.5	Solar PV	Photovoltaic	Not metered, no water use reported		---	---
G0386	NTC MCRD Energy Facility	25.6	Natural Gas	Combined			Potable	---
G0405	PE Berkeley Inc	26.3	Natural Gas	Combined			Potable	University of California Berkeley
G0775	Elk Hills Cogeneration	26.6	Natural Gas	Combustion Gas	Not metered, no water use reported		---	---
G0630	Phillips66 - Carbon Plant	27.3	Natural Gas	Steam	Did not report electricity generation related water uses, Mislabeled as G0805 in original dataset		Potable	---
E0098	Rio Bravo Fresno	27.8	Wood	Steam			Groundwater	Well(s)
E0099	Rio Bravo Rocklin	27.8	Wood	Steam			Potable	Placer County Water District
E0052	Covanta Mendota LP	28.0	Wood	Steam			Groundwater	Well(s)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0290	CP Kelco - San Diego Plant	28.0	Natural Gas	Combustion Gas	No water use reported		---	---
G0157	Pitchess Cogeneration Station	28.7	Natural Gas	Combined	Two or more orders magnitude annual variation in water-intensity		Recycled	Treated Waste Water
T0007	West Ford Flat #4	28.8	Geothermal	Steam			---	---
E0102	Wadham	29.0	Agriculture Crops	Steam			Groundwater	Well(s)
G0673	Wheelabrator Norwalk Energy	29.0	Natural Gas	Combined	Did not report electricity generation related water uses		Potable	Norwalk, City of
G0677	New-Indy Containerboard Ontario (Oxnard Paper Mill)	29.0	Natural Gas	Combustion Gas			Potable	---
G0923	Clearwater	29.0	Natural Gas	Combined			---	---
G0640	University of California San Diego Cogeneration Facility	30.0	Natural Gas	Combined	Not metered, no water use reported		---	---
S0070	SEGS II	30.0	Solar Thermal	Steam			Groundwater	Well(s)
G0221	OLS Energy - Agnews Inc.	30.5	Natural Gas	Combined			Groundwater	Well(s)
G0661	Watsonville	30.8	Natural Gas	Combined			Groundwater	Pajaro Valley Water District Well
E0005	Burney Forest Products	31.0	Wood	Steam			Potable	Burney Water District

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0173	Western Power and Steam Inc. (DAI Oildale)	31.0	Natural Gas	Combined	Not metered, no water use reported		---	---
G0636	United Cogen Inc (SFO)	31.0	Natural Gas	Combined			Potable	Hetch Hetchy
G0403	CI Power Cogeneration Plant (OLS Camarillo)	31.2	Natural Gas	Combined			Potable	---
G0404	OLS Energy Chino	31.2	Natural Gas	Combined			Potable	---
E0063	Scotia	32.5	Wood	Steam			Surface	Eel River
S0071	SEGS III	34.2	Solar Thermal	Steam			Groundwater	Well(s)
S0072	SEGS IV	34.2	Solar Thermal	Steam			Groundwater	Well(s)
S0074	SEGS V	34.2	Solar Thermal	Steam			Groundwater	Well(s)
G0286	Kingsburg Cogeneration	34.5	Natural Gas	Combined			Other Impaired Water	Condensate from Sun Maid Rinse Water
E0112	Southeast Resource Recovery	34.6	Municipal Solid Waste	Steam			Potable	---
S0075	SEGS VI	35.0	Solar Thermal	Steam			Groundwater	Well(s)
S0076	SEGS VII	35.0	Solar Thermal	Steam			Groundwater	Well(s)
E0212	Total Energy Facilities	35.2	Other Biomass Gas	Combined			---	---
E0041	HL Power Company (Honey Lake)	35.5	Wood	Steam			Groundwater	Well(s)
C0002	Los Angeles Refinery - Calciner	35.8	Coal	Steam			Potable	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
T0012	Del Ranch Company (A W Hoch)	35.8	Geothermal	Steam			---	Well(s)
T0015	J J Elmore	35.8	Geothermal	Steam			Groundwater	Imperial Irrigation District
T0034	J M Leathers	35.8	Geothermal	Steam			Surface	Imperial Irrigation District
G0638	Berry Cogen Midway-Sunset	37.2	Natural Gas	Combustion Gas			Potable	West Kern Water District
G0547	Sargent Canyon Cogeneration	38.2	Natural Gas	Combustion Gas			Recycled	Produced Water from oil extraction
C0018	Rio Bravo Jasmin	38.3	Coal	Steam			Surface	Kern-Tulare Water District
C0022	Rio Bravo Poso	38.3	Coal	Steam			Groundwater	Well(s)
G0131	Coalinga Cogeneration Facility	38.4	Natural Gas	Combustion Gas			---	---
G0520	Salinas River Cogeneration	38.9	Natural Gas	Combustion Gas			Recycled	Produced Water from oil extraction
G0355	Mid-Set Cogeneration	39.1	Natural Gas	Combustion Gas			Potable	---
T0053	Vulcan	39.6	Geothermal	Steam			---	---
G0409	Oildale	40.0	Natural Gas	Combustion Gas			---	---
G0912	Springs Generation Project	40.0	Natural Gas	Combustion Gas			Potable	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0562	AltaGas Pomona Energy Inc	42.0	Natural Gas	Combustion Gas			Potable, Other Impaired Water	---
G0625	U S Borax Inc	42.0	Natural Gas	Combustion Gas			Other	Mojave Cogen Company demineralized water supply
G0032	Berry Placerita Cogen	42.8	Natural Gas	Combustion Gas			Groundwater	Placerita Community Lease #5 API # 037-14280
G0763	UCLA Energy Systems Facility	43.0	Natural Gas	Combined			Potable	Los Angeles Department of Water and Power
G0924	Chula Vista Energy Center LLC	44.0	Natural Gas	Combustion Gas			Potable	---
G0897	Red Bluff	44.8	Natural Gas	Internal Combustion Engine	Not metered, no water use reported		---	---
S0313	Camelot LLC	45.0	Solar PV	Photovoltaic	Not metered, no water use reported		---	---
G0821	Drews - Agua Mansa (Alliance Colton)	45.2	Natural Gas	Combustion Gas			Potable	---
G0842	Century (Alliance)	45.2	Natural Gas	Combustion Gas			Potable	---
G0399	North Island Energy Facility	46.2	Natural Gas	Combined			Potable	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0906	Wellhead Power Gates LLC	46.5	Natural Gas	Combustion Gas			---	---
G0910	Cuyamaca Peak Energy Plant (CalPeak El Cajon)	46.8	Natural Gas	Combustion Gas			Potable	Helix Water District
G0040	Badger Creek Cogen	47.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0149	Corona Cogen	47.0	Natural Gas	Combustion Gas			Surface	---
G0315	Live Oak Cogen	47.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0339	McKittrick Cogen	47.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0428	Bear Mountain Cogen	47.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0429	Chalk Cliff Cogen	47.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0823	King City Energy Center	47.3	Natural Gas	Combustion Gas			Potable	---
G0914	Riverview Energy Center	47.3	Natural Gas	Combustion Gas			---	---
G0902	Valero Cogeneration Unit #1	47.7	Natural Gas	Combustion Gas			Potable	Benicia, City of
G0925	THUMS	47.8	Natural Gas	Combustion Gas			---	---
G0176	Double C	48.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0258	High Sierra	48.0	Natural Gas	Combustion Gas			Groundwater	Well(s)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0292	Kern Front	48.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0529	San Joaquin Cogen	48.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0662	Walnut	48.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G9222	Center Peaker	48.0	Natural Gas	Combustion Gas			Potable	Golden State Water Co
G0913	Wolfskill Energy Center	48.1	Natural Gas	Combustion Gas			Potable	---
G0915	Lambie Energy Center	48.1	Natural Gas	Combustion Gas			---	---
G0916	Goose Haven Energy Center	48.1	Natural Gas	Combustion Gas			---	---
G0917	Feather River Energy Center	48.1	Natural Gas	Combustion Gas			Potable	---
G0918	Creed Energy Center LLC	48.1	Natural Gas	Combustion Gas			---	---
G0919	Yuba City Energy Center	48.1	Natural Gas	Combustion Gas			Potable	---
G0180	EF Oxnard Inc.	48.5	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0845	Enterprise - CalPeak Power	48.9	Natural Gas	Combustion Gas			Potable	Rincon Del Diablo Water District
G0686	Yuba City Cogeneration Partners LP	49.0	Natural Gas	Combustion Gas			Potable	---
G1041	McGrath Peaker	49.0	Natural Gas	Combustion Gas			---	---
G9111	Barre Peaker	49.0	Natural Gas	Combustion Gas			Potable	City of Stanton

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G9333	Etiwanda Peaker	49.0	Natural Gas	Combustion Gas			Potable	Cucamonga Valley Water District
G9444	Mira Loma Peaker	49.0	Natural Gas	Combustion Gas			Potable	City of Ontario
G0026	Anaheim CT	49.2	Natural Gas	Combustion Gas			Potable	---
G0951	El Cajon Energy Center	49.2	Natural Gas	Combustion Gas			---	---
G0908	Panoche - CalPeak Power	49.6	Natural Gas	Combustion Gas			Potable	Baker Framing Company Firebraugh, CA.
G0202	ExxonMobil Las Flores Canyon	49.8	Natural Gas	Combined			Groundwater	Well(s)
G0853	Border - CalPeak Power	49.8	Natural Gas	Combustion Gas			Potable	Otay Water District
G0504	Rockwood Gas Turbine Plant	49.9	Natural Gas/Oil	Combustion Gas			---	---
G0564	Ripon Cogeneration Facility	49.9	Natural Gas	Combustion Gas			Recycled	Ripon, City of
G0626	Naval Station Energy Facility	49.9	Natural Gas	Combined			Potable	United States Navy
G0905	Wellhead Power Panoche LLC	49.9	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0909	Vaca Dixon - CalPeak Power	49.9	Natural Gas	Combustion Gas			Potable	Vacaville, City of
G1049	Delano Energy Center LLC	49.9	Natural Gas	Combustion Gas	Not metered, no water use reported		Groundwater	Well(s)
T0017	Salton Sea Unit 5	49.9	Geothermal	Steam			---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
T0081	North Brawley	49.9	Geothermal	Steam			---	---
G0239	Greenleaf 2 Inc.	50.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
S0246	Alpaugh 50 LLC	50.0	Solar PV	Photovoltaic			Potable	Alpaugh Irrigation District
G0896	Chowchilla II Peaker	50.1	Natural Gas	Internal Combustion Engine	Not metered, no water use reported		---	---
G0632	ConocoPhillips Company San Francisco Refinery	51.0	Other Gas	Combustion Gas	Mislabeled as G0630 in original dataset		Potable	---
T0016	Salton Sea Unit 4	51.0	Geothermal	Steam			---	---
G0233	Goal Line LP	51.5	Natural Gas	Combined			Potable	City of Escondido
E0127	Puente Hills Energy Recovery	52.8	Landfill Gas	Combustion Gas and Steam			Recycled	---
G0080	Cardinal Cogen	52.8	Natural Gas	Combined			Potable	---
T0049	Salton Sea Unit 3	54.0	Geothermal	Steam			---	---
E0027	Desert View Power (Mecca Plant)	54.1	Wood	Steam			Groundwater	Well(s)
T0080	Bottle Rock Power	55.0	Geothermal	Steam			---	---
C0021	Stockton Cogen	55.1	Coal	Steam			Groundwater	Well(s)
G0195	Ellwood Generating Station	56.7	Natural Gas	Combustion Gas			Air-Cooled	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
S0243	Copper Mountain I	58.0	Solar PV	Photovoltaic	Not metered, no water use reported, Located in Nevada		Potable	Boulder City Utility
G0384	Fresno Cogeneration Partners LP	58.2	Natural Gas	Combined			Groundwater	Well(s)
G0084	Carson Cogeneration Co	60.0	Natural Gas	Combined			Potable	---
G0516	South Belridge Cogen Facility	60.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0063	Lake 1	60.5	Natural Gas	Combustion Gas	Two or more orders magnitude annual variation in water-intensity		Recycled	---
C0017	Argus Cogen Plant	62.5	Coal	Steam			Brackish Groundwater	Well(s)
T0033	Heber Geothermal Co	62.5	Geothermal	Steam			---	---
E0086	Wheelabrator Shasta	62.7	Wood	Steam	Not metered, no water use reported		Groundwater	Well(s)
C0016	Mt. Poso Cogeneration	63.6	Coal	Steam			---	---
E0232	Mt. Poso Cogeneration (Repowered after C0016 was retired)	63.6	Other Biomass Gas	Steam	Not metered, no water use reported		---	---
G0228	Gianera	64.0	Natural Gas	Combustion Gas	Generated less than 500 MWh electricity		---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0177	Pittsburg	65.7	Natural Gas	Combustion Gas			Surface	DOW Chemical
S0237	Alpine Solar	66.0	Solar PV	Photovoltaic	Did not report electricity generation related water uses		Groundwater	Well(s)
G0759	ConocoPhillips Los Angeles Refinery Wilmington Plant	68.5	Other Gas	Combined Single Shaft			---	---
G0238	Greenleaf 1 Inc.	72.0	Natural Gas	Combined			Groundwater	Well(s)
G0335	McClellan	74.2	Natural Gas	Combustion Gas			Potable	---
G0061	Broadway	75.0	Natural Gas	Steam			Groundwater	Well(s)
T0046	Sonoma #3	78.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0051	Second Imperial Geothermal Co SIGC Plant	80.0	Geothermal	Steam			Groundwater	Well(s)
G0536	Algonquin Power Sanger LLC	83.0	Natural Gas	Combined			Potable	Sanger, City of
G0776	Los Angeles Refinery (Tesoro)	83.0	Natural Gas	Combined			Brackish Groundwater	Well(s)
G0819	Larkspur Energy LLC	90.0	Natural Gas	Combustion Gas			Surface	San Diego, City of

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0832	Hanford Energy Park Peaker	92.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
S0073	SEGS IX	92.0	Solar Thermal	Steam			Groundwater	Well(s)
S0077	SEGS VIII	92.0	Solar Thermal	Steam			Groundwater	Well(s)
G0130	Coachella	92.4	Natural Gas	Combustion Gas			Surface	Imperial Irrigation District
S0244	Copper Mountain II	94.5	Solar PV	Photovoltaic	Not metered, no water use reported, Located in Nevada		Potable	Boulder City Utility
G1023	Miramar Energy Facility 1 & 2	95.0	Natural Gas	Combustion Gas			Surface	San Diego, City of
T0060	Big Geysers #13	95.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0050	Calistoga #19	97.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
G0220	Malaga Peaking Plant	98.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0867	Henrietta Peaker	98.0	Natural Gas	Combustion Gas			Groundwater	Westlands Water District
G0204	MID Ripon	100.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0755	Martinez Refinery	100.0	Natural Gas	Combined	Not metered, no water use reported		Surface	Contra Cost Water District
T0009	Coso Energy Developers (BLM)	100.0	Geothermal	Steam			Groundwater	Well(s)
T0011	Coso Power Developers (NAVY II)	100.0	Geothermal	Steam			Groundwater	Well(s)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
T0010	Coso Finance Partners (NAVY I)	102.4	Geothermal	Steam, Double Flash			Groundwater	Well(s)
G0246	Harbor Cogeneration Co	107.4	Natural Gas	Combined			Surface	Los Angeles Department of Water and Power
C0001	ACE Cogeneration	108.0	Coal	Steam			Brackish Groundwater	Searles Valley Minerals
G0410	Olive	109.8	Natural Gas	Steam			Recycled	Burbank, City of
T0039	Geothermal 1	110.0	Geothermal	Steam			Recycled, Surface	Lake County
T0040	Geothermal 2	110.0	Geothermal	Steam			Recycled, Surface	Lake County
T0055	McCabe #5-#6	110.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0056	Ridge Line #7-#8	110.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0057	Fumarole #9-#10	110.0	Geothermal	Steam	Did not report electricity generation related water uses		Other	---
T0058	Eagle Rock #11	110.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0059	Cobb Creek #12	110.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
G0336	McClure	112.0	Natural Gas/Oil	Combustion Gas			Surface	Don Pedro Reservoir via the Tuolumne River
T0061	Sulphur Springs #14	117.5	Geothermal	Steam, Dry			Recycled, Surface	City of Santa Rosa and Lake Co. Recycled Water, Clear Lake Surface

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
								water, Stormwater capture, and surface water from a local creek
G0085	Sacramento Carson - Carson Ice CG	119.5	Natural Gas	Combined and Combustion Gas			Recycled	Sacramento County
G0468	The Procter & Gamble Paper Products Co	119.6	Natural Gas	Combustion Gas			Potable	Oxnard, City of
G0006	CES Placerita Inc.	120.0	Natural Gas	Combined	No electricity generation reported		Potable	Newhall County Water District
T0027	Quick Silver #16	120.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0028	Lakeview #17	120.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0029	Socrates #18	120.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
T0030	Grant #20	120.0	Geothermal	Steam, Dry			Recycled, Surface	Santa Rosa, City of and Lake County
G0931	Niland Gas Turbine Plant	121.0	Natural Gas	Combustion Gas			Surface	Colorado River
G0229	Calpine Gilroy Cogen L.P.	123.4	Natural Gas	Combined			Recycled	---
S0078	Ivanpah I (Solar Partners II)	126.0	Solar Thermal	Steam		Air	Groundwater	Well(s)
G0613	Martinez Cogen Limited	127.5	Natural Gas	Combined			Surface	Contra Costa Water District

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
S0255	Imperial Solar Energy Center South	128.9	Solar PV	Photovoltaic			Surface	Imperial Irrigation District
S0292	Arlington Valley Solar Energy II	129.0	Solar PV	Photovoltaic	Located in Arizona		Groundwater	Well(s)
G0019	Calpine King City Cogeneration LLC	130.0	Natural Gas	Combined			Groundwater	Well(s)
S0079	Ivanpah II (Solar Partners I)	133.0	Solar Thermal	Steam		Air	Groundwater	Well(s)
S0080	Ivanpah III (Solar Partners VIII)	133.0	Solar Thermal	Steam		Air	Groundwater	Well(s)
G0818	Indigo Generation LLC	135.0	Natural Gas	Combustion Gas			Groundwater	Onsite groundwater wells
G0105	Chevron El Segundo Refinery Cogeneration	137.0	Natural Gas	Combined			Recycled	West Basin Municipal Water District, California Water Service, and wells 4S/13W-21J02S, 4S/13W-16J05S
G0894	Malburg Power Plant	139.4	Natural Gas	Combined			Recycled	---
G0998	Midway LLC - Starwood Power - CalPeak Power	139.8	Natural Gas	Combustion Gas	Two or more orders magnitude annual variation in water-intensity		Recycled	Baker Farming Company (filter backwash water)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0822	Gilroy Energy Center	141.9	Natural Gas	Combustion Gas			Recycled, Brackish Groundwater	---
G0169	Donald Von Raesfeld Power Plant	147.0	Natural Gas	Combined			Recycled	South Bay Water Recycling
S0258	Campo Verde Solar Project	147.2	Solar PV	Photovoltaic			Surface	Imperial Irrigation District
S0254	Mesquite Solar 1	150.0	Solar PV	Photovoltaic	Located in Arizona		Groundwater	Well(s)
G0104	Chevron Richmond Refinery Cogeneration	165.6	Natural Gas	Combined Single Shaft and Steam			Recycled, Potable	East Bay Municipal Utility District
G0268	Humboldt Bay	167.0	Natural Gas	Internal Combustion Engine		Air	Ocean / Estuary	Pacific Ocean
G0076	Sacramento Campbell Soup SPA	174.0	Natural Gas	Combined			Surface	Sacramento, City of
S0252	Solar Star I (MidAmerican)	177.0	Solar PV	Photovoltaic	Not metered, no water use reported		Groundwater	Well(s)
G0231	Glenarm	178.6	Natural Gas	Combustion Gas	Two or more orders magnitude annual variation in water-intensity		---	---
G0487	Redding Power	182.3	Natural Gas	Combined and Combustion Gas			Surface	Redding, City of

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0679	Woodland Generation Station	184.6	Natural Gas	Combined Single Shaft and Combustion Gas and Internal Combustion Engine			Surface	Don Pedro Reservoir via the Tuolumne River
G0922	Riverside Energy Resource Center	192.0	Natural Gas	Combustion Gas			Recycled	Riverside, City of
G0467	Sacramento SCA	197.9	Natural Gas	Combined and Combustion Gas			Surface	Sacramento, City of
G0213	Roseville Energy Park	200.0	Natural Gas	Combined			Recycled	Roseville, City of
G1015	Mariposa Energy LLC	200.0	Natural Gas	Combustion Gas			Surface	Byron Bethany Irrigation District
G0058	Canyon Power Plant	200.4	Natural Gas	Combustion Gas			Recycled	Orange County Water District
G0016	Almond Power Plant	223.0	Natural Gas	Combustion Gas			Recycled	Ceres, City of
G0406	Oakland Power Plant	223.5	Jet Fuel	Combustion Gas			Potable	Smalling cooling tower used for balance of plant system cooling. (zero steam condensate return)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0358	Midway-Sunset Cogeneration	234.0	Natural Gas	Combustion Gas			Recycled	Produced Water from oil extraction
S0253	Solar Star II (MidAmerican)	235.5	Solar PV	Photovoltaic	Not metered, no water use reported		Groundwater	Well(s)
G0161	Crockett Cogeneration Project	247.4	Natural Gas	Combined Single Shaft		Air	Surface	East Bay Municipal Utility District
G0900	Walnut Energy Center	250.0	Natural Gas	Combined			Recycled	Turlock, City of
S0240	California Valley Solar Ranch	250.0	Solar PV	Photovoltaic	Did not report electricity generation related water uses		Groundwater	Well(s)
S0241	Antelope Valley Solar Ranch 1	250.0	Solar PV	Photovoltaic			Groundwater	Well(s)
S0256	Desert Sunlight 250	250.0	Solar PV	Photovoltaic	Did not report electricity generation related water uses		---	---
S0259	Genesis Solar Energy Project	250.0	Solar Thermal	Steam		Air	Groundwater	Well(s)
S0295	Copper Mountain III	255.0	Solar PV	Photovoltaic	Not metered, no water use reported, Located in Nevada		Potable	Boulder City Utility
G0319	Long Beach Generation LLC	260.0	Natural Gas	Combustion Gas	Did not report electricity generation related water uses		Brackish Groundwater	Plant Dewatering System

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0053	El Segundo Energy Center	263.0	Natural Gas	Combined	Did not report electricity generation related water uses		Recycled	West Basin Municipal Water District, California Water Service, and wells 4S/13W-21J02S, 4S/13W-16J05S
G0236	Grayson	287.0	Natural Gas	Combined and Combustion Gas and Steam			Recycled	---
S0242	Agua Caliente Solar	290.0	Solar PV	Photovoltaic	Located in Arizona		Groundwater	Well(s)
G0293	Kern River Cogeneration Co	300.0	Natural Gas	Combustion Gas			Recycled	Produced Water from oil extraction
G0590	Sycamore Cogeneration Co	300.0	Natural Gas	Combustion Gas			Recycled	Produced Water from oil extraction
S0257	Desert Sunlight 300	300.0	Solar PV	Photovoltaic	Did not report electricity generation related water uses		---	---
G0866	Los Esteros Critical Energy Facility LLC	325.6	Natural Gas	Combined in 2013-2014 but Combustion Gas in 2010-2012			Recycled	South Bay Water Recycling - City of San Jose
G0838	Tracy Peaker Plant	333.0	Natural Gas	Combined in 2012-		Air	Surface	Byron Bethany Irrigation District

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
				2014 but Combustion Gas in 2010-2011				
G0190	El Centro Generating Station	358.2	Natural Gas	Combined and Steam			Surface	Imperial Irrigation District
G0462	Potrero Generating Station	363.0	Natural Gas	Combustion Gas and Steam		Once-Through	---	---
G0329	Magnolia	387.6	Natural Gas	Combined			Recycled	Recycled Water and Groundwater
G0035	Watson Cogeneration Co	398.0	Natural Gas	Combined			Recycled, Potable, Groundwater	West Basin Municipal Water District, California Water Service, and wells 4S/13W-21J02S, 4S/13W-16J05S
G0997	Panoche Energy Center	400.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0889	Cosumnes Power Plant	500.0	Natural Gas	Combined			Surface	United States Bureau of Reclamation (conveyor of SMUD's water rights via the Folsom South Canal)
G0928	Walnut Creek Energy Park	500.5	Natural Gas	Combustion Gas			Recycled	Rowland Water District

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G1040	Desert Star Energy Center	536.0	Natural Gas	Combined	Located in Nevada		Potable	Boulder City, City of
G0245	Harbor	548.1	Natural Gas	Combined and Combustion Gas		Once-Through	---	---
S0245	Topaz Solar Farms LLC	550.0	Solar PV	Photovoltaic	Not metered, no water use reported		Groundwater	Well(s)
G0779	Sutter Energy Center - Calpine Construction Finance Co	551.8	Natural Gas	Combined		Air	Groundwater	Well(s)
G0861	Palomar Energy Center	559.0	Natural Gas	Combined			Recycled	Rincon del Diablo Municipal Water District
G0794	Metcalf Energy Center LLC	565.8	Natural Gas	Combined			Recycled	South Bay Water Recycling - City of San Jose
G0799	Elk Hills Power LLC	567.0	Natural Gas	Combined			Surface	West Kern Water District
G0784	Sunrise Power	572.0	Natural Gas	Combined			Surface	West Kern Water District
G0330	Mandalay Generating Station	573.3	Natural Gas	Steam and Combustion Gas		Once-Through	Ocean / Estuary	Pacific Ocean
G0780	Los Medanos Energy Center LLC	594.0	Natural Gas	Combined			Recycled	Delta Diablo
G0371	Morro Bay Power Plant	612.0	Natural Gas	Steam		Once-Through	Ocean / Estuary	Pacific Ocean

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0950	Gateway Generating Station	613.0	Natural Gas	Combined		Air	Surface	Antioch, City of
G0935	Russell City Energy Company LLC	640.0	Natural Gas	Combined			Recycled	Hayward, City of
G0767	Coolwater Generating Station	646.9	Natural Gas	Combined and Steam			Groundwater	Well(s)
G0201	Etiwanda Generating Station	666.0	Natural Gas	Steam			Recycled	Inland Empire Utilities Agency
G0194	El Segundo Power Station	670.0	Natural Gas	Steam	Did not report electricity generation related water uses	Air and Once-Through	Recycled	---
G9787	La Rosita	676.5	Natural Gas	Combined and Combined Single Shaft	Located in Mexico		Recycled	---
G0147	Contra Costa Power Plant	680.0	Natural Gas	Steam		Once-Through	Ocean / Estuary	Carquinez Strait
G9786	Termoelectrica de Mexicali	680.8	Natural Gas	Combined	Located in Mexico		Recycled	---
G0648	Valley Generating Station	682.0	Natural Gas	Combined and Combustion Gas			Recycled	Los Angeles Department of Water and Power
G0785	Otay Mesa Generating Project	689.0	Natural Gas	Combined		Air	Surface	Otay Water District

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0934	Colusa Generating Station	692.0	Natural Gas	Combined		Air	Surface	U.S. Bureau of Reclamation via Tehama Colusa Canal
G0797	Pastoria Energy Facility LLC	778.0	Natural Gas	Combined			Surface	Wheeler Ridge-Maricopa Water Storage District
G0512	Sentinel Energy Project CPV	800.0	Natural Gas	Combustion Gas			Groundwater	Well(s)
G0868	Inland Empire Energy Center	810.0	Natural Gas	Combined Single Shaft			Recycled	---
G0549	Scattergood	823.0	Natural Gas	Steam		Once-Through	---	---
G1011	Marsh Landing Generating Station	828.0	Natural Gas	Combustion Gas			Surface	Antioch, City of
G0778	High Desert Power Project	854.9	Natural Gas	Combined			Groundwater, Recycled	Well(s), Victorville, City of
G0274	Huntington Beach	860.0	Natural Gas	Steam		Once-Through	Ocean / Estuary	Pacific Ocean
G0783	Delta Energy Center LLC	860.2	Natural Gas	Combined			Recycled	Delta Diablo
G0196	Encina	965.0	Natural Gas	Combustion Gas and Steam		Once-Through	Ocean / Estuary	Pacific Ocean
G0795	Mountainview Generating Station	1,054.0	Natural Gas	Combined Single Shaft			Recycled, Brackish Groundwater	Redlands, City of, Well(s)
G0450	Pittsburg Generating Station	1,070.0	Natural Gas	Steam		Once-Through	Ocean / Estuary	Suisun Bay (brackish)

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
G0781	La Paloma Generating	1,200.0	Natural Gas	Combined Single Shaft			Surface	West Kern Water District
G0490	Redondo Beach LLC	1,354.8	Natural Gas	Steam	Two or more orders magnitude annual variation in water-intensity	Once-Through	Ocean / Estuary	Pacific Ocean
G0421	Ormond Beach Generating Station	1,612.8	Natural Gas	Steam		Once-Through	Ocean / Estuary	Pacific Ocean
G0249	Haynes Generating Station	1,776.0	Natural Gas	Combined and Combustion Gas and Steam		Once-Through	---	---
C0023	Intermountain Power Project	1,800.0	Coal	Steam	Located in Utah		---	---
G0011	Alamitos	1,969.7	Natural Gas	Steam		Once-Through	Ocean / Estuary	---
N0002	San Onofre Nuclear Generating Station	2,254.0	Nuclear	Steam	No water use reported	Once-Through	Ocean / Estuary	Pacific Ocean
G0372	Moss Landing Power Plant	2,484.0	Natural Gas	Combined Single Shaft and Steam		Once-Through	Ocean / Estuary	Monterey Bay
N0001	Diablo Canyon	3,557.0	Nuclear	Steam		Once-Through	Ocean / Estuary	Pacific Ocean
G0805	Mistake	Mistake	Mistake	Mistake	Reported water use was actually for G0630		---	---
G9300	Renamed	Renamed	Renamed	Renamed	Plant was renamed to G0922 in 2013,		---	---

Plant ID	Power Plant Name	Nameplate Capacity (MW)	Primary Fuel Type	Generation Technology	Reason Removed	Cooling System	Primary Water Type	Primary Water Source
					changed to G0922 for all years			
G0681	Typo	Typo	Typo	Typo	Typo. Should have been G0861.		---	---
G0945	Typo	Typo	Typo	Typo	Reported water use was actually for G0495, which is smaller than 20 MW in capacity		---	---