



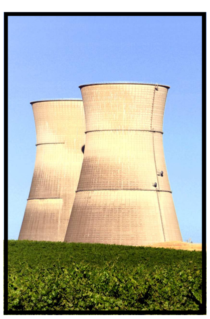

Donald Bren School of Environmental Science & Management
University of California, Santa Barbara

California's Energy-Water Nexus: Water Use in Electricity Generation

A Group Project Report
submitted in partial satisfaction of the requirements for the degree of
Master of Environmental Science and Management

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May 7, 2007

California's Energy Water Nexus: Water Use in Electricity Generation

As authors of this Group Project report, we are proud to archive it on the Bren School's website such that the results of our research are available for all to read. Our signatures on the document signify our joint responsibility to fulfill the archiving standards set by the Donald Bren School of Environmental Science & Management:

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The Group Project is required of all students in the Master of Environmental Science and Management (MESM) Program. It is a four-quarter activity in which small groups of students conduct focused, interdisciplinary research on the scientific, management, and policy dimensions of a specific environmental issue. This Final Group Project Report is authored by MESM students and has been reviewed and approved by:

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List of Acronyms and Abbreviations

AGR	Direct-heated Aboveground Retorting
BLM	United States Bureau of Land Management
Btu	British thermal unit
BWR	Boiling Water Reactor
°C	Celsius
CAISO	California Independent System Operator
CARB	California Air Resources Board
CATF	Clean Air Task Force
CEC	California Energy Commission
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CPV	Concentration photovoltaic systems
CSP	Concentrating solar power
CWA	Clean Water Act
DNI	Direct normal insolation
DOE	U.S. Department of Energy
DR	Demand response
DWR	California Department of Water Resources
EERE	Energy Efficiency and Renewable Energy (U.S. DOE)
EIA	U.S. Energy Information Agency (U.S. DOE)
EJ	Exajoule
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Emission Performance Standards
°F	Fahrenheit
FGD	Flue gas desulfurization
gal	Gallon
GCM	General Circulation Model
GHG	Greenhouse gas
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt-hour
h	Hour
HCM	Hadley Centre Model
HERO	High-efficiency reverse osmosis

HSRG	Heat recovery steam generator
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
ISL	In-situ leaching
J	Joule
kJ	Kilojoule
km	Kilometer
km^3	Cubic kilometer
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water & Power
LCA	Life-cycle assessment
m	Meter
m^3	Cubic meter
Mgal	Megagallon
mph	Miles per hour
MIS	Indirect-heated AGR, Modified In-Situ
MJ	Megajoule
MW	Megawatt
MWh	Megawatt-hour
MWh(e)	Megawatt-hour (electric)
MWh(t)	Megawatt-hour (thermal)
NCEC	Nevada Clean Energy Coalition
NEI	Nuclear Energy Institute
NETL	National Energy Technology Laboratory (U.S. DOE)
NO_x	Nitrous oxides
NRC	U.S. Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory (U.S. DOE)
PCC	Pulverized coal combustion
PCM	Parallel Climate Model
PCU	Power conversion unit
PG&E	Pacific Gas & Electric Company
PIER	Public Interest Energy Research (CEC)
PNW	Pacific Northwest
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic

PWR	Pressurized Water Reactor
QF	Qualifying facility
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SDWA	Safe Drinking Water Act
SO_x	Sulfur oxides
SWP	California State Water Project
TMDL	Total maximum daily load
TOU	Time-of-use
USGS	United States Geological Survey
WQS	Water quality standards
WTE	Waste to energy
ZLD	Zero liquid discharge

Abstract

Water and energy are inextricably linked. Water is needed for energy production, and energy is needed for the extraction, conveyance, treatment, and distribution of water. Water requirements for electricity generation vary significantly, depending on the primary energy source, conversion technologies, and cooling technologies. Therefore, to meet future demands, integrated planning between both the energy and water sectors is essential. This analysis provides a tool that supports integrated planning by quantifying the water requirements for electricity generation from both renewable and non-renewable sources.

Using California as a case study, we assess the freshwater requirements for current and future electricity generation under several different energy portfolios. Our analysis demonstrates the potentially positive effects of investment in certain renewable resources such as solar photovoltaics, wind power, and waste-based bioenergy. Similarly, dry cooling technologies, if employed in thermoelectric power plants, can greatly diminish the electricity sector's impacts on freshwater resources. Conversely, increased reliance on dedicated energy crops or geothermal sources may have extraordinary impacts on freshwater resources. As existing freshwater supplies become increasingly taxed, allocations to the electricity sector may become limited. Consequently, policies that encourage resource conservation and integrated planning will be imperative.

Executive Summary

Introduction

The supply and demand for energy and water are intricately woven together. Water is needed in several stages of the electricity generation process, and energy is needed for water extraction, conveyance, distribution, and treatment. The water required for electricity generation varies considerably, and is a function of the primary energy source, as well as the conversion and cooling technologies. To meet future energy and water demands, integrated planning between the energy and water sectors is essential. By quantifying the water requirements for both renewable and non-renewable sources of electricity, we provide a tool to support integrated planning by water and electrical utilities.

Historically, energy and water issues have been examined independently, which has led to:

- Planning for future electricity production without considering how water requirements will be met over time, and
- Planning for future water resources (domestic potable water supply and wastewater treatment) with the assumption that electricity will be readily available and affordable.

Considering both sides of the energy-water nexus is vital in any major planning decision. Although the energy-water nexus has multiple dimensions, from local to international, the scope of this analysis was largely limited to exploring the water inputs to electricity generation. While this analysis has global applicability, we use California as a case study.

We focused our efforts on answering two main questions:

- How much water is required to produce electricity at each step of the generation process?
- How much water will California need to satisfy future electricity demand?

Background & Significance

The complexity of California's water distribution system clearly demonstrates the connection between energy and water. The geographic disparity of water and population in California – two-thirds of the state's water is in Northern California, while two thirds of the population lives in Southern California – led to the creation of the State Water Project (SWP), an energy-intensive system of pumps and channels that moves water from northern to southern California. The SWP uses an average of 12.2 billion kWh a year to move this water (Trask, 2005).

The amount of electricity used by the SWP is likely to increase, given population projections. California's population is slated to reach 46.4 million by 2030, a 37.1 percent increase from 2000 (U. S. Census Bureau, 2005). Nearly half of the population growth is expected to occur in the South Coast Region, increasing that region's annual water demand by over 1.2 billion cubic meters (DWR, 2005).

Escalating demands for electricity and water affect not only the future growth and planning of the electricity market and water delivery systems, but also the environment. As the world's sixth largest economy (Legislative Analyst's Office, 2004), California consumes 79.9 billion cubic meters of water (DWR, 2004) and 235 billion kWh of electricity (California Energy Commission, 2005a) annually; shortages of either could jeopardize California's economy. In order to sustain California's prosperity and population growth and preserve its unique natural environment, informed analysis, planning, and policy changes in the energy and water sectors are needed.

Approach

To quantify the water required to generate electricity, we collected data from numerous sources, identifying the water requirements at each step of the generation process. These data were compiled in an Excel workbook. Using California as a case study, we assessed the freshwater requirements for current and future electricity generation under several different energy portfolios.

All commercially implemented renewable and non-renewable primary energy sources, electricity generation technologies, and cooling technologies were included in the workbook. The non-renewable primary energy sources include coal, natural gas, nuclear fuels, and oil. The renewable energy sources include biomass, geothermal, solar, wind, and water (hydropower). We collected data for each step of the energy generation process, for every primary energy source. These steps include irrigation (for dedicated energy crops), mining, transportation, processing (fuel conversion), cooling, cleaning, and other technology-specific applications. Not all forms of electricity generation require water in each of these step; in fact, many require water in only two or three steps. We also collected data for different technological options for each primary energy source. For example, within coal, fuel conversion technologies include both combustion and gasification; for each of these, various methods of cooling such as once-through, recirculating wet, and dry cooling can be used. Finally, high and low estimates of water withdrawals and consumption were included for each step and technology of the electricity generation process (in m^3/MWh).

These data form the basis for our scenario analyses and web-based tool. The web-based tool serves as a user-friendly interface that allows users to project the water withdrawn and consumed for any electricity portfolio. The tool encourages integrated energy and water resource planning by utilities, and is designed to be applicable for users in different locations with diverse electricity generation portfolios. The workbook that supports the web-based tool can be easily modified, should a user want to add additional energy sources, technologies, or conversion processes.

After collecting and compiling our raw data, we compared our projected annual water withdrawals with USGS estimates in four counties: Monterey, San Diego, San Luis Obispo, and San Bernardino. Once the data was verified, we used it to quantify the water requirements for California's current energy portfolio, as well as eight future energy portfolios for the state. The ten portfolios are as follows:

- Scenario 1: 2005 – Baseline
- Scenario 2: 2010 – Projected RPS
- Scenario 3: 2020 – Projected RPS
- Scenario 4: 2030 – Increased demand from 2020 with the same (projected) RPS
- Scenario 5: 2020 – Fossil fuel based energy mix
- Scenario 6: 2020 – Projected RPS, coupled with water-efficient technologies (dry cooling and integrated gasification combined cycle coal (IGCC) processing)
- Scenario 7: 2020 – Water-efficient mix of primary energy sources
- Scenario 8: 2020 – Water-efficient primary energy sources and water-efficient technologies
- Scenario 9: 2020 – Technology focused approach, including coastal natural gas plants (on wet recirculating cooling)
- Scenario 10: 2020 – Technology focused approach, including coastal natural gas plants (on dry cooling)

Results & Discussion

Our results show that water requirements for electricity generation vary greatly, depending on the primary energy source, the conversion technologies employed, and the cooling technologies employed. It is difficult to make generalizations about the water use for renewable and non-renewable sources of energy. Some renewable sources of energy like geothermal and bioenergy derived from dedicated energy crops may require significant amounts of water, while other renewables like solar photovoltaics and wind power typically require negligible amounts of water. Likewise, electricity generated from fossil fuels can require large or small quantities of water, depending on the cooling technology employed. In addition, the conversion efficiency of a plant can impact the water requirements; a natural gas plant using combined cycle technologies captures more of the natural gas's latent energy than a simple cycle plant, decreasing the water required per unit of electricity generated.

Our analysis demonstrates the potentially positive effects of investment in certain renewable energy resources and more water-efficient technologies. Several points resonate: renewable resources such as solar and wind power, and technologies such as dry cooling in thermoelectric power plants, can substantially diminish the electricity sector's water requirements. In contrast, increasing reliance on dedicated energy crops and geothermal resources may amplify the electricity sector's water requirements. In general, the factor responsible for the greatest impact on the water required for electricity generation is the type of cooling technology utilized. Biomass and geothermal energy represent the two main exceptions to this trend.

Converting coastal, seawater cooled natural gas plants to freshwater cooling systems without altering the cooling technologies currently employed would have substantial impacts on freshwater resources. Our results suggest, however, that by adopting dry cooling systems, conversion of coastal natural gas plants can have minimal impacts on freshwater resources. While conversion to dry cooling is associated with a 20 percent energy penalty, recent legislation suggests that future use of seawater for cooling purposes will be limited in California. In comparison, converting these power plants' cooling systems to recirculating wet cooling will have a more substantial impact on freshwater supplies, but significantly less than the current dominant technology, once-through cooling.

Recommendations & Conclusions

Our results demonstrate that a water-efficient energy portfolio can be developed from a mix of primary energy sources, conversion technologies, and cooling technologies. Thus, utility investments should focus on increasing water-efficient electricity generation such as solar photovoltaics, wind power, and dry cooling systems in thermoelectric power plants.

In order to provide adequate future supplies of energy and water, future policies must address the energy-water nexus. Policies that encourage water conservation by electricity utilities can greatly assuage future water requirements. For example, conservation credits for energy utilities that implement programs to reduce electricity use can also reduce water demand. In addition, integrated planning of water and energy infrastructure will offer numerous benefits. For example, increased use of reclaimed water in power plants reduces demand on traditional freshwater sources. The co-location of wastewater treatment facilities and power plants serves as a prime example of integrating water and energy infrastructure.

Finally, we recommend that current research gaps be addressed at the federal, state, and private levels. These gaps include:

- A thorough life cycle assessment (LCA) of electricity generation for each method of generating electricity, including water use for facility construction (power plants or solar panels). These LCAs are necessary in order to understand the full water requirements of electricity generation.
- A feasibility analysis of water-efficient energy portfolios. This analysis is needed to facilitate the development of reliable infrastructure. The most appropriate mix of primary energy sources and cooling technologies must be feasible, and will depend on available resources, patterns of demand, and economic barriers.

Introduction

Our research explores the inextricable link between energy and water. The extraction, conveyance, treatment, and distribution of water all require energy, while many steps of the electricity production process requires water. Until recently, electrical utilities and water districts typically were separate entities, with little or no joint planning. The main goal of this project is to support integrative planning of water and energy resources, which we accomplished by:

- Creating a tool that quantifies the water requirements for electricity produced from each of the nine major commercially implemented primary energy sources. This information is available in a user-friendly web-based tool.
- Helping plan and host the First Western Forum on Energy & Water Sustainability, held on March 22-23, 2007 in Santa Barbara, California. This forum facilitated communication and partnership between utilities, laboratories, research firms, and government agencies working on the both side of the nexus, allowing participants to share their knowledge and discuss future strategies.

Using California as a case study, our research assesses the freshwater requirements for current and future electricity generation under several different energy portfolios. Our analysis demonstrates the potentially positive effects of investment in certain renewable resources and more water-efficient technologies, as well as the effect of switching coastal once-through cooled power plants onto recirculating freshwater systems.

Background

The Energy-Water Nexus

The relationship between energy and water is one that is often overlooked, despite the escalating consequences of doing so. In the future, both the availability of freshwater and the cost of energy will likely become limiting factors of economic development and population growth. Although energy production and water supply are often thought of as two separate systems, energy is required to provide water and water is required to generate energy. More specifically, water is needed for electrical energy production, and energy is needed for water extraction from subsurface reservoirs, desalination, conveyance in surface channels, distribution to users, treatment pre- and post-use, and storage of reclaimed water. System inefficiencies exacerbate shortages, and shortages indicate that tighter, integrated systems are needed.

Historically, energy and water issues have been examined independently, which has led to:

- Planning for future electricity production without fully considering available freshwater supplies

- Planning for future water resources (domestic potable water supply and wastewater treatment) with the assumption that electricity will be readily available and affordable.

Considering both sides of the energy-water nexus is vital in any major planning decision. Although the energy-water nexus is an international issue, the scope of this paper will be largely limited to exploring the water inputs to power plants within the state of California.

California's Energy-Water Nexus

California's energy crisis of 2000-2001 brought to attention the issue of reliable energy supplies, while California's history of droughts has made water scarcity a perpetual concern. The energy-water nexus will become increasingly important, as California's population is expected to reach 40 million by 2012, 50 million by 2036, and 55 million by 2050 (California Department of Finance, 2004). Compounding this growth, the greatest population increases will be in the arid areas of the state, including Riverside County, which is projected to grow by 2.8 million, and in the San Joaquin Valley, which is projected to double in population over the next fifty years (Heim, 2004). Given these population projections, demand for both water and electricity will likely increase, making joint planning and its related resource use efficiency gains essential.

The scarcity of potable water in the arid western U.S. has recently begun to influence energy policy. Jon Wellinghoff, of The Nevada Clean Energy Coalition (NCEC), said in a recent interview, "There's no way Washoe County has the luxury anymore to have a fossil-fuel plant site in the county with the water issues we now have. It's too important for the county's economic health to allow water to be blown up in the air in a cooling tower." Following this sentiment, the NCEC is fighting a Sempra-proposed coal plant in Nevada. Sempra had already scaled back the project from 1,450 MW to 1,200 MW due to water availability issues, and after initial studies, the sustainable water rights sought dropped from 19,735,709 cubic meters to 14,801,782 cubic meters per year (Voyles, 2006).

Energy Demands for Water

In 2001, the withdrawal, collection, conveyance, treatment, distribution, and end-use of water accounted for 19 percent of California's total electricity use (Krebs, 2006). Several factors affect the energy intensity of each of these steps; these factors include the location of the end use in relation to the water source, the water quality regulations in the area of consumption, and specific requirements related to the type of end use (e.g. on-site heating, cooling, or softening).

The single largest consumer of electricity in California is the State Water Project (SWP). Planned, designed, constructed, and now operated and maintained by the

California Department of Water Resources (DWR), this unique facility provides water supplies for 23 million Californians and 364,217 hectares of irrigated farmland (Klein et al., 2005). The SWP pumping plants (used to move water from Northern California to Southern California, which includes lifting the water over the Tehachapi Mountains) currently consume 8 million MWh of electric energy each year, while the associated generating plants produce an average of about 6 million MWh per year. The project thus has a net energy use of about 2 million MWh (Trask, 2005). The total energy used to pump and treat water in the state is 6.5 percent of the total state's electricity usage, 2-3 percent of which is used solely for pumping (California Energy Commission, 2004b).

Demand for water in California is greatest in locations with little natural supply, which accounts for most of the variability of water's embedded energy intensity. To illustrate, two-thirds of California's precipitation falls in the northern part of the state, while two-thirds of the state's population lives in Southern California. Conveyance of water to Southern California accounts for the difference in energy intensity of water in Northern and Southern California. Studies completed in Southern California found that the average energy use for water treatment is 0.53 kWh/m^3 (Hoffman, 2004). While that number may seem large, it pales in comparison to the energy needed to *pump* water. According to California's Department of Water Resources (DWR), "water pumping is the single most significant use of electricity in the state, using 5 percent of the state's peak load and 7 percent of the total electricity usage in California" (Lofman et al., 2002).

Environmental and ecological restrictions on the use of water for electricity generation will also shape the way energy production evolves. The protection of aquatic species and habitat, for example, places limitations on cooling water withdrawals. In addition, growth and development in the greater region will limit future availability of surface water supplies. For example, increasing development in the Upper Colorado River basin and completion of the Central Arizona Project threaten California's ability to continue withdrawing in excess of its Colorado River water allocation (Hoffman, 2004). Even with extensive water conservation, California's water demand in 2030 is projected to reach 300,000 – 6,200,000 hectares (Krebs, 2006). Additionally, as California's surface and groundwater resources become overtaxed or contaminated, more efficient use of both potable and reclaimed water will become critical.

Reducing the energy required to withdraw, pump, and treat water could help reduce the likelihood of power interruptions during peak energy consumption, and push back the need for additional power generating facilities and thus additional demands on water supplies. Statewide operating energy reserves are typically around seven percent, but become precipitously low under hot weather conditions, due to high air conditioning loads (Chaudhry, 2005). In terms of annual peaks, Northern California reaches its seasonal electricity demand peak in July, while Southern California usually reaches its peak demand two months later, in September. Although these peak demand periods typically total only between 50-100 hours per year, they impose huge burdens on the electric system (Jones, 2005). These summer months are also the months when water is typically the scarcest.

Peak Electricity Demand

Peak electricity demand depends on load profile and time of year, among other factors. Peak demand periods occur both seasonally and daily, and vary according to weather and patterns of electricity use. Peak demand influences the type of generating facilities constructed, the total generating capacity needed for a region, and the cost of electricity.

While baseload power plants operate continuously, stopping only for maintenance or unexpected outages, peaker plants, or "peakers", are turned on only when immediate additional electricity is needed to meet demand. Due to the need to produce rapid power at a moment's notice, peakers are generally single cycle plants, and thus less efficient than combined cycle baseload plants. A simple cycle plant can reach full generating capacity notably faster (in a matter of minutes) than a combined cycle plant, which may require several hours. Some peakers run a few hours each day, while others run only a few hours per year. Regardless, it is critical that they reach generating capacity expediently.

A load profile is a graph created using measurements of a customer's electricity use at regular intervals, typically one hour or less. It provides an accurate representation of a customer's usage pattern over time.

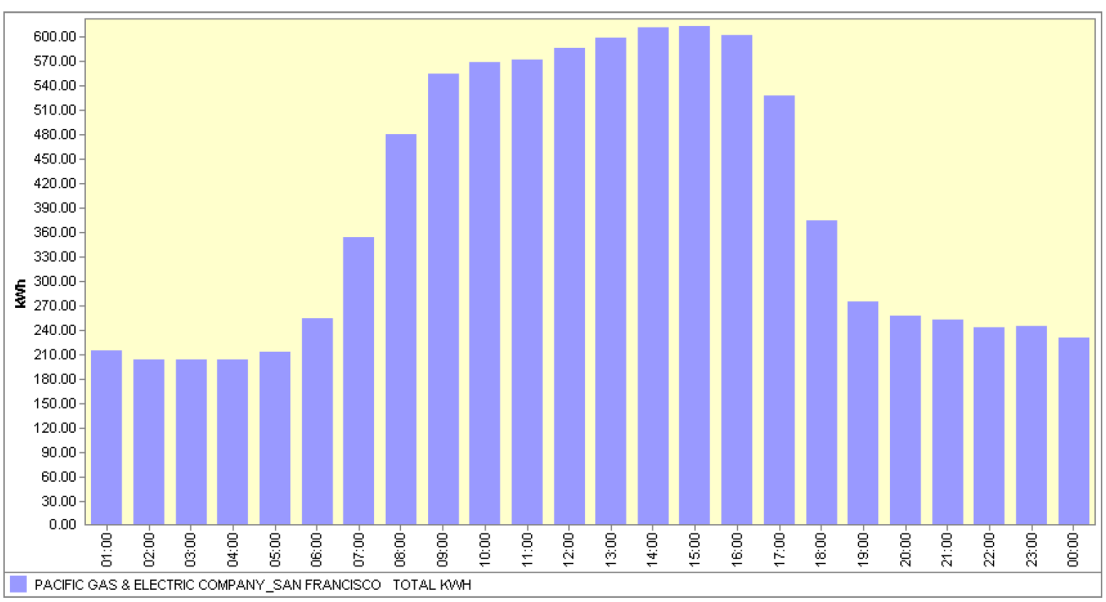


Figure 1. Typical daily load profile in Pacific Gas & Electric's service area (PG&E, 2005).

Weather may have the greatest influence on energy use. In California, demand for air conditioning during the hot summer months represents peak electricity demand. Colder regions' peak demand may occur during the winter, coinciding with high heating needs (PG&E, 2006). During the summer peak demand periods, the California Independent System Operator (CAISO) purchases a greater percentage of their electricity from the spot market, which typically is notably more expensive than power purchased through long-term contracts.

Peak demand also occurs on a daily basis, typically in the late afternoon and early evening. Peak shaving involves customer curtailment of load at specific times of the day, either by request of that customer's retail power supplier or in response to real-time price signals. Peak shaving programs utilize demand side management strategies to help average out daily loads. One approach to shaving peak electricity use is through alternative rate structures. Time-of-use (TOU) plans encourage customers to use less electricity during peak hours of the day by making electricity consumed on-peak more expensive than that consumed during off-peak hours. Another type of peak shaving program is called demand response (DR). Demand response programs vary in depth and breadth, but generally focus on voluntary electricity use reductions by the commercial sector on days when shortages are expected.

Renewable sources of energy have variable capacities for meeting peak and baseload demand. The solar energy profile, for example, coincides well with peak electricity demand (Figure 2). The wind energy profile, however, varies according to location, and most of California's wind resources do not correspond to peak demand. In fact, on a daily basis, peak wind power generation is almost opposite that of daily peak electricity demand (Figure 3). Seasonally, wind resources in California peak prior to electricity demand (Figure 4). Baseline power plants such as natural gas, biomass, coal, and oil, on the other hand, can generate electricity consistently, at all times, providing an undisputed advantage over more intermittent energy sources.

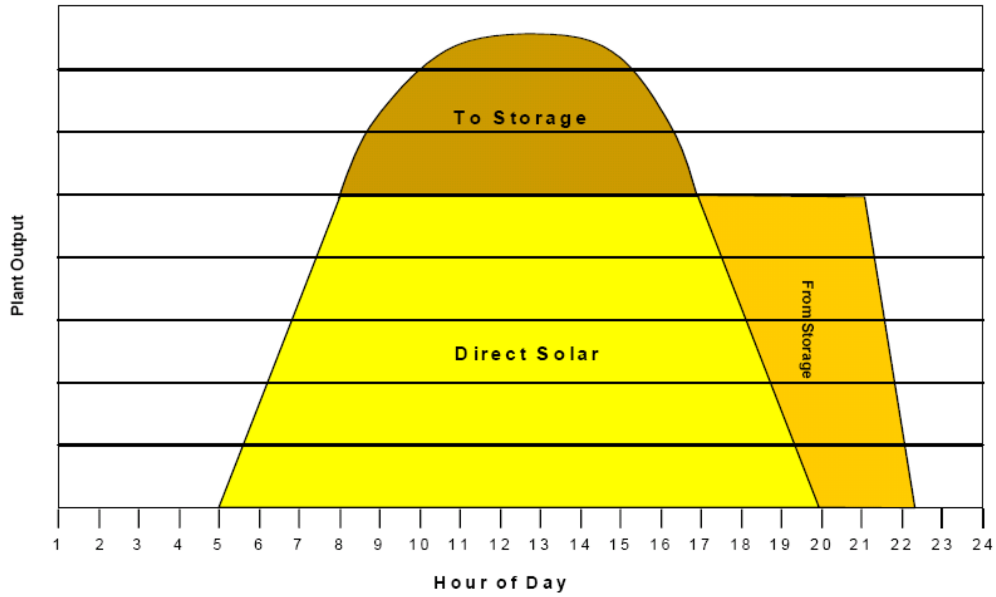


Figure 2. Conceptual parabolic trough plant with thermal storage, direct solar power is available during the period of the day shaded yellow (Stoddard et al. 2006).

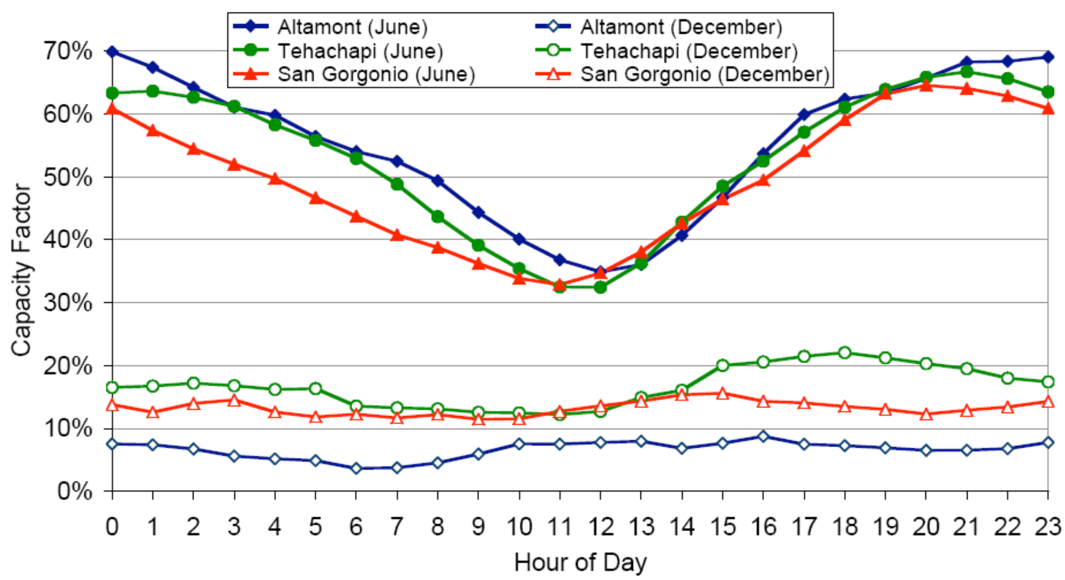


Figure 3. California diurnal wind profiles for June and December by resource area (Wiser, 2005).

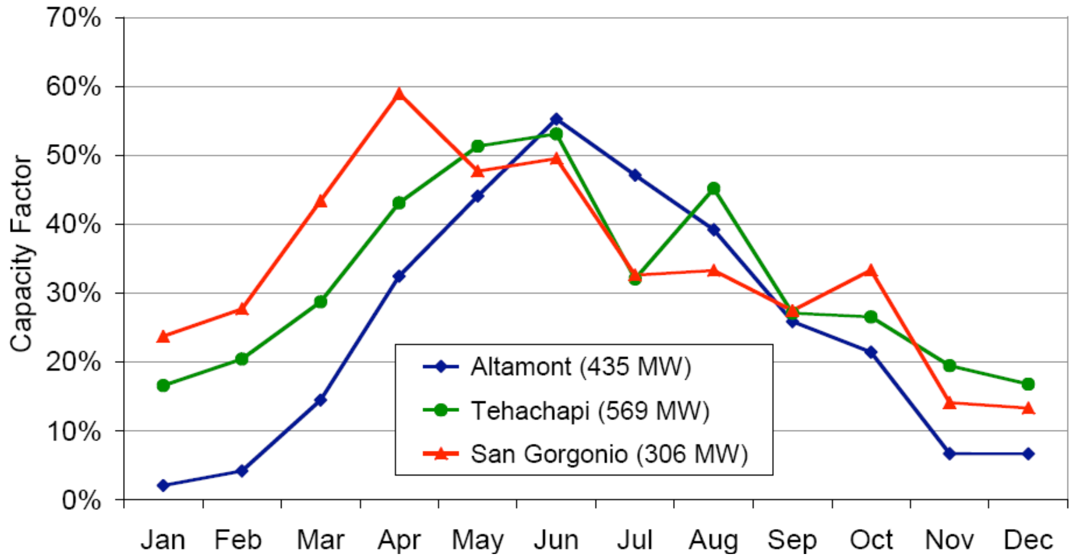


Figure 4. California monthly wind profiles by project (Wiser, 2005)

Pumped storage hydroelectric facilities represent a low-cost, baseload source of power with a production capacity that can be manipulated to match peak demand. At night, or other times of low electricity demand, water is pumped to a reservoir at a higher elevation. When demand is high, the water is released and used to generate hydroelectric power. Pumped storage hydroelectric facilities consume low-value (off-peak) energy and generate high-value (on-peak) electricity (Lofman et al., 2002). While this process is a net consumer of electricity, it is economically beneficial because of the higher value of peak electricity.

Water Requirements for Electricity Production

United States Geological Survey (USGS) data show that thermoelectric generation – including coal, oil, natural gas, and nuclear power generation – ranks only slightly behind agricultural irrigation as the largest user of freshwater withdrawals in the United States (Figure 5); (Hutson et al., 2004). In volumetric terms, thermoelectric power plants withdraw almost 515 million cubic meters of freshwater each day, with the bulk of it being used for cooling. Most of this water, however, is not consumed, which is reflected in Figure 6.

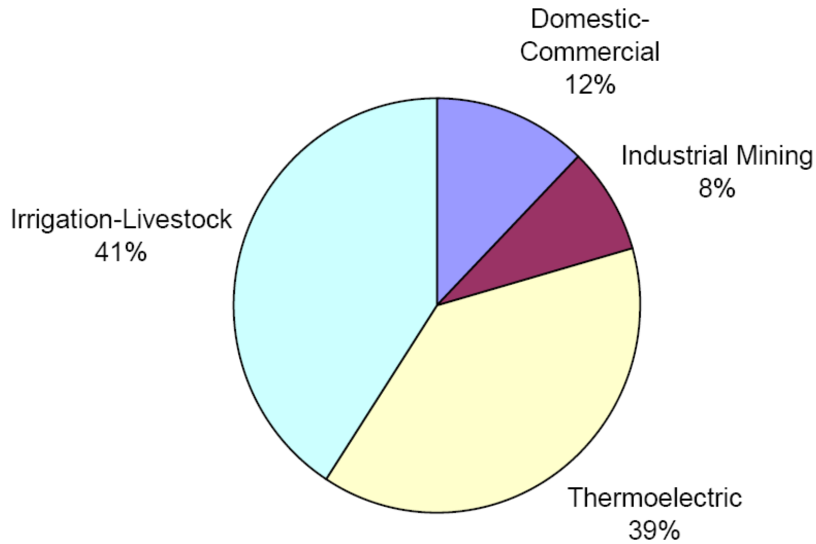


Figure 5: Percentage of total water withdrawals in the United States (Torcellini et al., 2003).

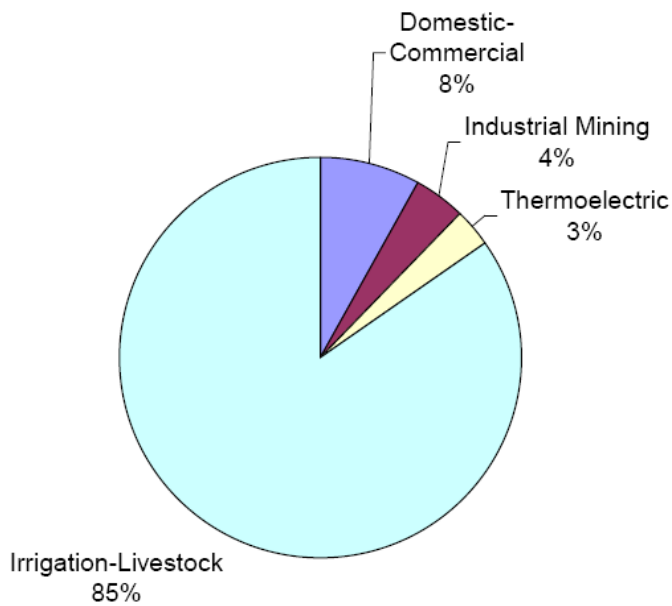


Figure 6. Percentage of total water consumption in the United States (Torcellini et al., 2003).

As defined by the EPA, water withdrawal refers to water extracted from surface or groundwater sources, with consumption being that part of a withdrawal that is ultimately used and removed from the immediate water environment whether by evaporation, transpiration, incorporation into crops or a product, or other consumption (EPA, 2006b).

Thermoelectric power plants use significant amounts of water for cooling; amounts of water that far surpass the water required for any other step of the electricity generation process. A 500 MW power plant using once-through cooling withdraws over 45,420 cubic meters of water per hour, with only a small amount going to non-cooling process requirements (Feeley et al., 2005). The California Energy Commission (CEC) (2001) estimates that of the 53.2 GW of generating capacity in California, 40 percent uses once-through cooling. The remaining 60 percent is divided evenly between hydroelectric and wind facilities (30 percent) and thermoelectric facilities using recirculating cooling (30 percent) (EPRI, 2002c).

USGS data show that electricity production from fossil and nuclear energy requires 719 million cubic meters of water per day, or 39 percent of all freshwater withdrawals nationally. According to Energy Information Administration (EIA) projections, the nation's growing population and economy coupled with the retirement of 65 GW of inefficient, older generating capacity, will necessitate 347 GW of new capacity (including end-use combined heat and power (CHP) by 2030 (Figure 7). Until recently it was expected that California's portion of this capacity would be imported from coal-fired plants built in other western states (Energy Information Administration, 2006a), but due to AB 32 and revisions to California's Renewable Portfolio Standards (RPS) this may not longer be the case (See General Energy Policies and Climate Change Policies for more information).

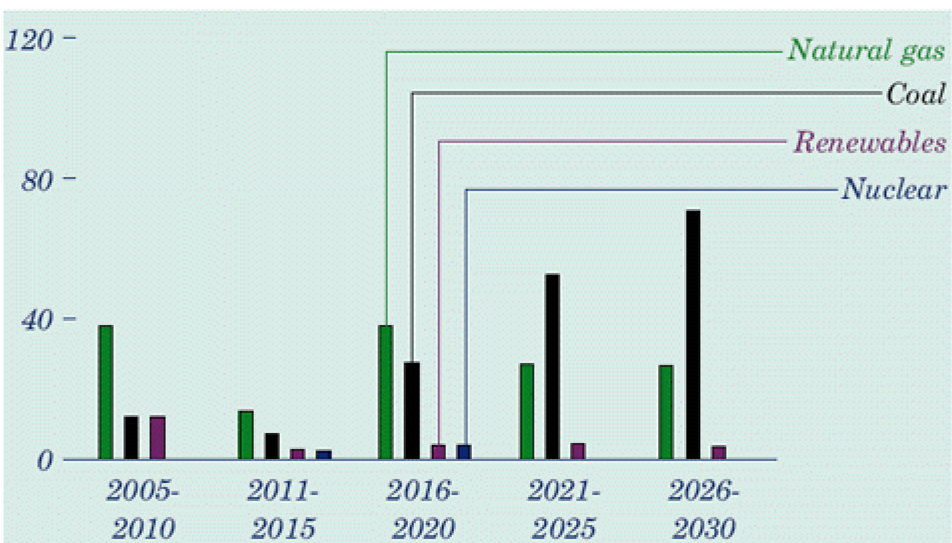


Figure 7. Electricity generation capacity additions by fuel type, including combined heat and power, 2005-2030, in gigawatts (Energy Information Administration, 2006a).

This expected demand increase of 347 GW assumes that California's per capita energy use will remain flat or decline, which has been the pattern since the mid-1970s (Figure 8) due to a high-level emphasis on energy efficiency and conservation measures. These measures have been so successful that in 2003, the state was ranked the foremost energy-efficient state, with an average energy consumption of 6,732 kWh per capita (California Energy Commission, 2006e). Figure 8 illustrates that without these programs in place, future per capita electricity demand would have been much higher in the state, as it has been in the rest of the nation.

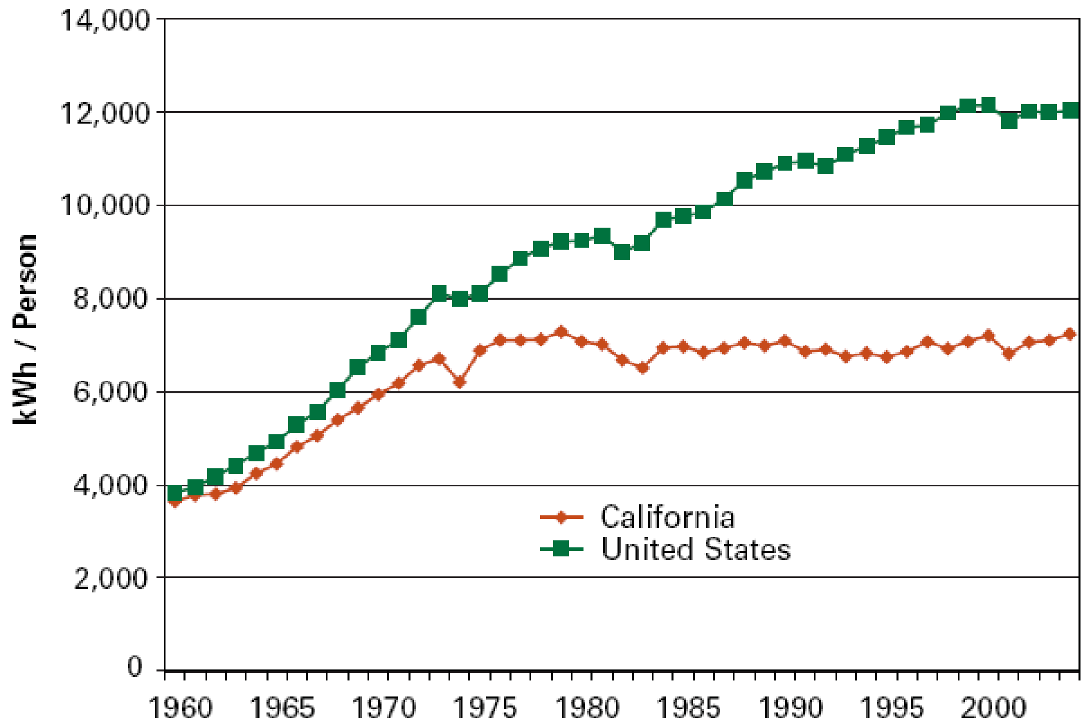


Figure 8. Per capita electricity use in California and the U.S., 1960-2004 (California Energy Commission & California Public Utilities Commission, 2006).

Climate Change and the Energy-Water Nexus in California

Introduction

Over the next century, anthropogenically-driven climate change will likely have significant consequences for California's interlinked water and energy systems. Particularly in regions where water supplies are already over-allocated, understanding and preparing for the possible effects of climate change is essential. Reduced freshwater supplies, for example, may limit the amount of water available for traditional energy generation. Similarly, existing municipal and agricultural demands may trump water demands for irrigating dedicated energy crops.

Climate change may also directly influence electricity supply and demand. Fossil-fuel based electricity generation emits significant amounts of greenhouse gases. Emissions of these gases contributes to climate change and may be further limited in the future, impacting fossil fuel based electricity generation capacity. Higher temperatures may increase demand for electricity, particularly during the summer months, when electricity demand peaks. Some forms of electricity generation, including solar and wind power, represent promising forms of future generation, regardless of the impacts of climate change.

Impacts on the Water Sector

Temperature and precipitation change predictions vary, depending on the general circulation model (GCM) and the greenhouse gas emissions scenario employed. While all models predict an increase in regional temperatures, they disagree on both the magnitude and direction of changes in regional precipitation. Two climate change scenarios, projected by the Parallel Climate Model (Washington, 2000) and the Hadley Centre Model, version 2 (Johns et al., 1997), bracket the range of possibilities for temperature and precipitation changes in California. A more detailed analysis of the impacts projected by these models is attached (Appendix 1).

By most projections, California will experience moderate warming; it lies between the more substantial warming projected for high latitudes and the milder warming expected in subtropical latitudes. Similarly, due to its coastal location, it falls between the more significant warming likely over the North American continent and the mild warming predicted for the Northern Pacific Ocean (Dettinger et al., 2004). The Western U.S. may be particularly sensitive to climate change, however. Small changes in temperature may be accompanied by more dramatic changes in patterns of precipitation (Coquard et al., 2004).

The Parallel Climate Model (PCM) projects mild global warming and a small increase in global precipitation; the Western U.S., however, is predicted to experience decreased rates of precipitation. The Hadley Centre Model (HCM) predicts a more substantial temperature increase and an increase in both global and regional precipitation. Both models predict earlier snowmelt runoff, which could exacerbate late summer drought conditions regardless of net changes in precipitation (Trask, 2005)

Three main hydrologic regions provide water supplies and hydroelectric power to California: the Central Valley (Sacramento and San Joaquin Rivers), the Colorado River Basin, and the Columbia River Basin. The Central Valley has an average runoff of 1314.2 cubic meters per second. (DWR, 1951), while the Colorado River has historically supplied up to 207.3 cubic meters per second to southern California (DWR, 2005). In addition, the hydroelectric facilities on the Colorado supply 6.3 – 7.3 million MWh of electricity annually (U.S. Bureau of Reclamation, 2006), while dams in the Columbia River basin generate hydroelectric power during the summer peak demand season. Changes in precipitation and runoff in these three regions will affect available water and hydroelectric supplies in California.

The Parallel Climate Model (PCM) projects decreased annual runoff in California's Central Valley and in the Colorado River basin, and no significant change in the Columbia River basin. The PCM projects earlier runoff in all three basins as more precipitation falls in the form of rain and less as snow (Vanrheenen et al., 2004); (Christensen et al., 2005); (Payne et al., 2004). Historically a valuable natural resource, increased volumes of springtime runoff may strain reservoir storage systems and increase flood hazards. In addition, earlier melting of snowpack may extend the hot, dry summer season. As a result, competition for available water supplies between the municipal, agricultural, environmental, and electricity sectors will likely increase.

Changes in the timing of runoff also have important impacts on hydroelectric power generation. In the Columbia River basin, earlier snowmelt and decreased summer runoff may result in less hydroelectric power generation during the summer months, when most power deliveries to California occur. Likewise, the small changes in runoff in the Colorado River basin have much larger impacts on total reservoir storage, which directly affects hydroelectric generation capacity. In California, earlier runoff and flood control demands may require water managers to lower reservoir levels, spilling water in the early spring months (when hydroelectric power supplies are not needed), and leaving less water for hydroelectric generation during peak summer months.

The Hadley Centre Model (HCM) projects increased rates of precipitation and, accordingly, runoff. Similar to the PCM, more of this precipitation will likely fall during the winter months in the form of rain, increasing flood hazards and straining reservoir storage systems. These hazards may demand a greater drawdown of reservoir levels during the winter and spring months. If, however, the reservoir and conveyance systems can adapt to and accommodate the increased flows, either through enlarged storage and conveyance facilities or adaptive management, hydroelectric power production may increase.

Decreased available water supplies will disproportionately impact certain sectors. Urban supplies will not likely be reduced substantially, due to urban users' higher willingness to pay, while agricultural supplies are likely to decrease. This may directly affect the type of crops grown in California, including dedicated energy crops (for bioenergy production), as farmers preferentially grow the most profitable crops.

Several tactics may help mitigate the impacts of climate change on the energy-water nexus in California; the following tactics perform well under both scenarios of climate change. Modifying patterns of water and electricity demand can help mitigate both water supply shortages and lost hydroelectric generation. Groundwater storage can effectively dampen fluctuations in interannual variability (both groundwater banking and conjunctive use) (Zhu et al., 2006), and tapping "backstop" water source technologies such as wastewater reuse and desalination can diminish arid urban areas' need to import water. More specifically, recycled water may serve as an important, dependable source of cooling water in the electricity sector. Adjusting flood control and reservoir drawdown requirements may mitigate some of the losses in hydropower generation, both in California and the Columbia River basin. Finally, in California, the DWR's classification of the water year type (i.e. critically dry, dry, below normal, above normal, or wet) defines the amount of water required to flow into the delta and subsequently, allocations to other water users. The classification hinges on runoff in the current year and in the prior year. Adjusting this classification scheme may lead to more efficient water management, benefiting all sectors (Vanrheenen et al., 2004).

Energy Demand

In addition to its direct effects on water availability and hydroelectric generation, climate change may have secondary impacts on both water and energy demand in California. Average daily temperatures show a direct relationship to energy use; on exceptionally cold days, customers use more electricity for indoor appliances and heating, and on higher temperature days, customers use more electricity for cooling indoor areas (the lowest energy demand corresponds to an outside temperature of approximately 12° C, or 55° F) (Franco & Sanstad, 2006). In addition, an increase in summertime daily temperatures, when demand peaks, has important implications for supply management.

Predictions of future average and peak energy demand are based on an empirical relationship between annual energy demanded and average daily temperatures, and the relationship between peak energy demanded and maximum daily temperatures. Franco and Sanstad (2006) present a comparison of the projected impact of climate warming under the Parallel Climate Model and the Hadley Centre Model for future periods, 2005 – 2034, 2035 – 2064, and 2065 – 2099. The Hadley Centre Model warming employs the A1Fi emissions scenario, while the Parallel Climate Model uses the A2 emissions scenario (both described in detail in the Intergovernmental Panel on Climate Change Special Report: Emissions Scenarios).

Table 1. Change in electricity demanded under future projections of climate change (Franco & Sanstad, 2006).

Model	Period	Annual Electricity Demand (% Increase)	Peak Electricity Demand (% Increase)
PCM A2	1	1.2	1.0
	2	2.4	2.2
	3	5.3	5.6
Hadley Centre Model (3) A1Fi	1	3.4	4.8
	2	9.0	10.9
	3	20.3	19.3

Several other factors are important to consider in electricity supply management. For example, in addition to overall changes, the variability of daily temperatures increases under the Hadley Centre Model projections; by the end of the 21st century, the standard deviation of simulated daily temperatures increases by more than 50 percent. In addition, the preceding analysis bases energy supply and demand on the current demographics of California, and ignores the trend of increasing development in the warmer interior areas of the state. Finally, while climate change may drive consumption, demographic trends, economic growth, changes in energy markets, and other policy decisions also affect demand; these changes should not be ignored in future planning (Franco & Sanstad, 2006).

Regardless, preparing for the impacts of climate change is essential. Several tactics may help mitigate its impact on California's energy system. Photovoltaics, for example, mimic the diurnal demand for electricity, and may effectively supplement energy supplies (Franco & Sanstad, 2006). Alternatively, demand may be reduced by reducing the heat island effect of urban areas or implementing conservation techniques.

California's Current Energy Portfolio

Electricity Generation – In-state

In 2005, just over 226,000 GWh of electricity were generated in California, and an additional 62,000 GWh were imported from out of state (California Energy Commission, 2007a). Generation included both renewable and non-renewable resources, with the largest portion derived from natural gas facilities, followed by nuclear and hydroelectric generation (Table 2). As of August 2006, California had 966 operational plants with capacities greater than 0.1 MW, and a total generating capacity of 62,613 MW. Approximately 20 percent of these facilities are 1 MW or smaller, and 50 percent of the state's facilities are 10 MW or smaller (California

Energy Commission, 2006a). The largest three plants, a gas facility (Moss Landing[1]) and two nuclear generators (San Onofre[2] and Diablo Canyon[3]), have generation capacities of 2,545; 2,200; and 2,160 MW, respectively.

Table 2. Electricity generation in California during 2005 (California Energy Commission, 2005d).

Resource	Generation (Gigawatt-hours, 2005)	Percent of Total Electricity Generated
Natural Gas	96,047	42
Nuclear	36,155	16
Hydropower	39,891	18
Coal	28,129	12
Geothermal	14,380	6.2
Organic Wastes	6,027	2.7
Wind	4,084	1.8
Solar	660	0.3
Oil	148	0.1

The primary means of generating electricity varies substantially throughout the state (Figure 9): Los Angeles and other large metropolitan areas with high baseload demand rely primarily on fossil fuels like natural gas and coal. The state's two nuclear plants, San Onofre and Diablo Canyon, provide a considerable portion of the electricity demanded in the San Diego Gas and Electric (SDG&E) and Pacific Gas and Electric (PG&E) service areas, respectively. Most of the state's hydroelectric power is generated in or near the Sierra Nevada Mountains; Sonoma and Lake Counties generate most of the state's geothermal power, and the windy passes in Riverside and Kern Counties provide most of the wind power. The power mix for each of the four largest service providers, Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), Los Angeles Department of Water & Power (LADWP), and San Diego Gas & Electric (SDG&E) reflects these regional differences in generation (Table 3).

[1] Located in Monterey County.
[2] Located in San Diego County.
[3] Located in San Luis Obispo County.

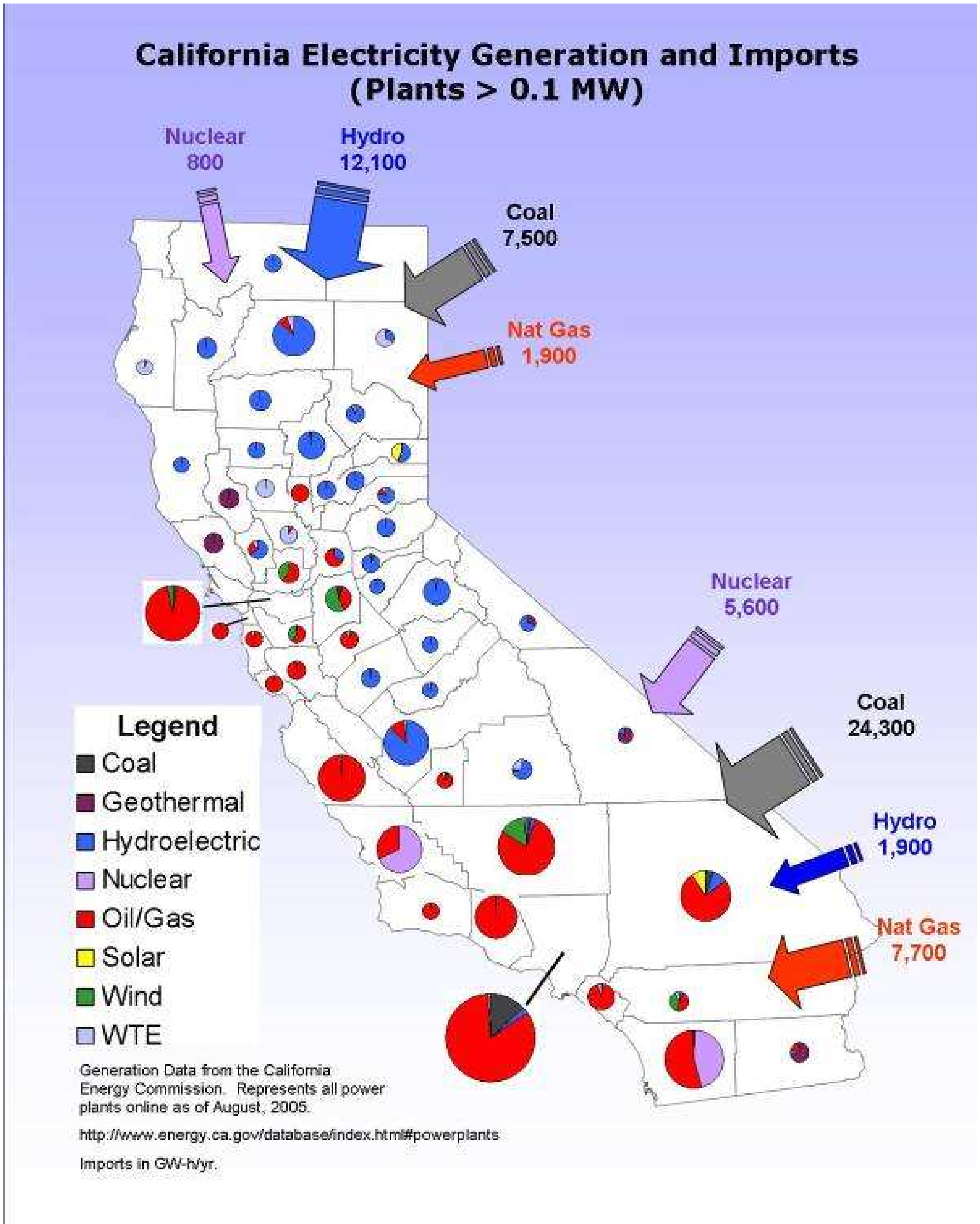


Figure 9. Electricity generation in California and out of state imports, as of 2005 (California Energy Commission, 2006a).

Table 3. Power mix for major California utilities in 2007 (projected) (Utilities power content labels 2006).

	PG&E	SCE	LADWP	SDG&E*
Eligible Renewables	**14 %**	**16 %**	**8 %**	**7 %**
Biomass & Waste	4 %	2 %	2 %	2 %
Geothermal	4 %	9 %	<1 %	2 %
Small hydroelectric	4 %	1 %	6 %	<1 %
Solar	<1 %	1 %	<1 %	<1 %
Wind	2 %	3 %	1 %	2 %
Coal	**3 %**	**7 %**	**47 %**	**19 %**
Large Hydroelectric	**17 %**	**6 %**	**7 %**	**10 %**
Natural Gas	**43 %**	**51 %**	**29 %**	**49 %**
Nuclear	**23 %**	**20 %**	**9 %**	**15 %**
Other	**1 %**	**<1 %**	**<1 %**	**0 %**

*SDG&E projections are for 2006

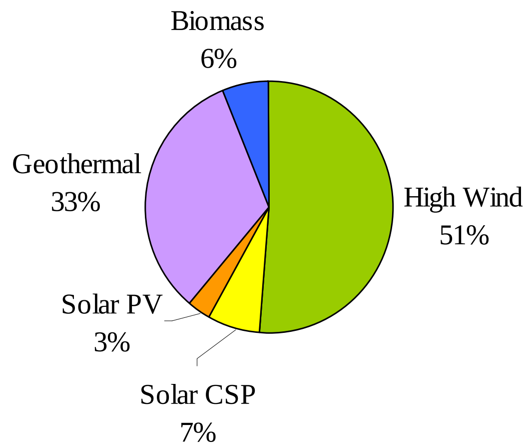
California's Renewable Portfolio Standard (RPS)
Renewable portfolio standards (RPS) are state policies requiring electricity providers to obtain or generate a minimum percentage of electricity from renewable resources by a certain date. Twenty states, plus the District of Columbia have RPS policies, representing more than 42 percent of the U.S. electricity sales (USDOE - EERE, 2007).

California's RPS was enacted by Senate Bill 1078 on September 12, 2002 and went into effect on January 1, 2003. The RPS requires 20 percent of the electricity purchased or generated by investor-owned utilities to be from renewable sources by 2010. An additional goal of 33 percent renewables by 2020 has also been set (California Energy Commission, 2007c).

Under the California RPS, IOUs are required to increase their renewable purchases by 2 percent per year to reach at least the 20% by 2010 and 33% by 2020 goals. Eligible renewables under the RPS include, biomass, biodiesel, fuel cells using renewable fuels, digester gas, geothermal, landfill gas, municipal solid waste, ocean wave, ocean thermal, tidal current, photovoltaic, small hydroelectric (30 MW or less), solar thermal, and wind (California Energy Commission, 2006d).

Several factors have contributed to the current patterns of electricity generation in California. Historically, natural gas and coal have been cheap, reliable resources that can support the state's baseload demands. Similarly, nuclear facilities provide reliable baseload energy. Because water has not typically been a limiting factor, most thermoelectric facilities rely on once-through cooling. While many of these facilities are located on the coast and withdraw seawater for cooling, environmental concerns surrounding their impacts on marine life may limit future withdrawals and the ability to site new plants on the coast. With the exception of hydroelectric power, broad-scale electricity generation from renewable resources has developed only in recent years. By 2010, however, California's Renewable Portfolio Standard (RPS) will require the state's Investor Owned Utilities (IOUs) to obtain 20 percent of their electricity from renewable resources. The utilities' anticipated mix of renewable energy is outlined in Figure 10. An additional goal of 33 percent renewables by 2020 has also been set. The project renewable energy mix is also outlined in Figure 10.

Projected Energy Generation from Renewable Sources, 2010	
Additional capacity	7,319 MW
Additional generation	29,000 GWh



Projected Energy Generation from Renewable Sources, 2020	
Additional capacity	19,157 MW
Additional generation	69,852 GWh

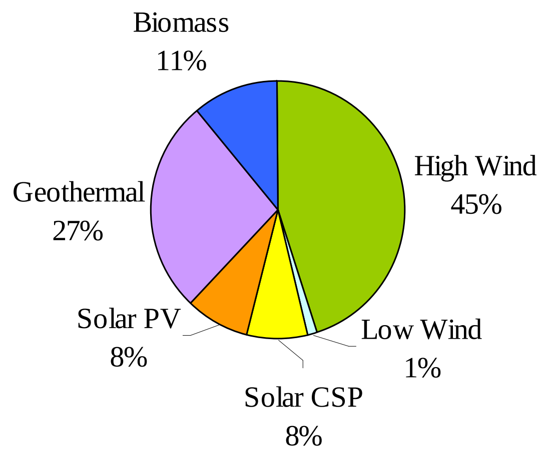


Figure 10. Projected breakdown of renewable energy sources in California. Increased capacity and generation are in addition to existing resources in 2006 (Public Interest Energy Research, 2006).

Electricity Generation – Imports

California received 22 percent of its electricity, or 62,456 GWh, from the Pacific Northwest (PNW) and the desert Southwest in 2005. Most of the electricity delivered from the PNW is generated from hydropower plants along the Columbia and Snake River systems. This electricity is purchased during California's peak demand periods in spring and summer, when demand in the PNW is low. In turn, electricity generated in California or the desert Southwest may be delivered to the PNW during the winter, their peak demand period (when electricity needs for heating and light are high). Approximately two-thirds of California's electricity imports come from the southwestern states of Utah, New Mexico, Arizona, and Nevada (Figure 9); transmission facilities can support the delivery of up to 4,500 MW of electricity to Southern California from this region. Contributing power facilities include the Palo Verde Nuclear Generating Facility; the Navajo, Four Corners, and Mohave coal plants; and Hoover Dam.

The substantial coal resources of the southwestern U.S. and the hydropower resources of the PNW have been the dominant factors in shaping these regions' patterns of electricity generation. These resources have served as cheap sources of electricity for California, and have been less subject to price fluctuations than natural gas, the primary source of in-state generation (Budhraja et al., 2003). Hydroelectric power from the PNW and Hoover Dam (Nevada), however, is vulnerable to climate fluctuations. Stricter air quality standards and increasing demand for limited water resources may also restrict increases in energy generation from coal-powered plants. In addition, growing energy demand in these regions may limit future exports to California. Both the PNW and desert Southwest have untapped wind and solar resources; these may represent likely future sources of power for California.

Retirement/Decommissioning

The decommissioning, repowering, and siting of power plants presents both opportunities and challenges to California energy providers, and may have important implications for mitigating the energy-water nexus. By 2008, California will retire between 4,630 and 7,232 MW of generation capacity (Table 4); (California Energy Commission, 2004a). Industry analysts have speculated that this number could be as high as 10,000 MW (California Energy Commission, 2004a). By diminishing the state's reserve margins, the retirement of a large number of aging plants can have a significant effect on reliability. Excluding anticipated retirements and including expected power plant additions, reserve margins for the state during the summers of 2005 – 2008 were expected to become very thin (California Energy Commission, 2004a). This, indeed, was the case during the summer of 2006. In addition to broad, regional concerns about reliability, the plants' retirement may have more localized impacts.

Table 4. Aging power plant retirements (California Energy Commission, 2004a).

Aging Power Plant Retirements 2005-2008 Medium and High Risk Retirement Scenario					
	2005	2006	2007	2008	Cumulative MW
PG&E	1,046	1,016	0	990	3,052
SCE & SDGE	676	2,152	1,310	1,879	6,017
Three Utility Area Total	1,722	3,168	1,310	2,869	9,069

Commonly, power plants are certified for a thirty-year operation period by the CEC (Scholl, 2007). Aging power plants have higher operations cost because they require more maintenance, lack automated controls (and as a result, require more staff), and have greater fuel needs due to system inefficiencies. Typically, these plants generate more pollution (per MWh) than newer, more efficient plants (California Energy Commission, 2004a).

Older plants are often located near loading centers. As these plants are decommissioned, greater community awareness and concern may lead to conflicts regarding land use and noise, creating challenges for the repowering of existing plants (Richins et al., 1996). If siting issues force new plants away from urban centers where most of the energy demand is located, existing transmission lines may be inadequate to carry the increased load over larger distances. In addition, siting plants distant to population and demand centers increases line losses and overall system inefficiencies.

Electrical energy is lost when power is transported over distance as resistance in the wires creates friction and some energy is lost as heat. According to the U.S. Climate Change Technology Program (2003), "energy losses in the U.S. transmission and distribution (T&D) system were 7.2 percent in 1995, accounting for 2.5 quads of primary energy. Losses are divided such that about 60 percent are from lines and 40 percent are from transformers (most of which

The siting of new power plants has its own set of challenges. Often concerns from local residents near a proposed plant site will stall or derail planning (the NIMBY, or "not in my backyard" phenomenon). Repowering existing plants or constructing new plants may raise environmental justice[4] issues (Richins et al., 1996), in that a disproportionate share of energy-related pollution is borne by low-income and marginalized populations or minorities. Price and availability of air quality offsets may also affect new plant siting (Richins et al., 1996).

[4] The fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.

With so many aging power plants moving toward retirement, energy managers have several options; they can mothball the plant and look for generation development opportunities elsewhere (thus closing and abandoning the plant), they can repower the facilities as they are, they can repower them with significant upgrades (improved technologies and overall efficiency), or they can consider using the existing site for entirely new facilities that may even use a different primary energy source (i.e. converting from a natural gas to coal gasification facility). The retirement and decommissioning of older fossil based plants provides a unique opportunity for utilities to decrease their overall water use by building up their renewable portfolio (certain renewable generation technologies have very low water needs) or change plants over to new water efficient technologies such as dry cooling.

A limitation to the build up of renewables as a direct response to decommissioned plants is that renewable resources are not necessarily available at these specific sites. If decommissioned plants are mothballed, however, one option utilities have to regain the lost generation capacity and increase water use efficiency is to pursue off-site renewable generation such as wind power.

As older plants are often located near high load urban centers, keeping electrical generation on the same site as the retiring plant is advantageous it terms of minimizing transmission loss and the need for transmission line upgrades. Solutions to keeping generation near load centers while decreasing actual and perceived environmental justice issues include the installation of rooftop photovoltaic systems. These systems create no emissions and require almost no water (a very small amount is needed for washing to maintain efficiency); in general, cleaner generation technologies may face less community opposition. Regardless, these upcoming retirements constitute an opportunity for the accelerated implementation of new water efficient generation and cooling technologies.

Overview of Electricity Generation Technologies

All forms of electricity generation impact the environment, whether through resource extraction, land use, habitat destruction, or air and water pollution. While all electricity generation has an environmental cost, some generation technologies have substantially less impacts. This analysis acknowledges the environmental impacts of electricity generation, but focuses on its implications for water resources. It is a known fact, for example, that water is required to cool thermoelectric power plants. Water is also required, however, to extract, refine, develop, and transport fuels to power plants. Furthermore, the water that is used by power plants must be treated before it is released back into the environment.

Traditional, non-renewable forms of electricity generation have numerous associated environmental costs. Fossil-fuel based power plants, for example, emit greenhouse gases, toxins, and particulate matter. While nuclear plants produce no GHG emissions, the threat of nuclear disasters and the lack of available, safe, long-term disposal and storage facilities have made them controversial facilities. Large hydroelectric generation facilities have their share of associated concerns, most notably their impacts on riparian ecosystems.

Even the cleanest power plants face siting issues. Power plants and transmission lines require a large land area, and construction is subject to lengthy environmental impact assessments. Often, communities do not want power plants near residential areas, forcing generating facilities to locate in more remote areas, potentially impacting pristine lands.

Despite current investment and excitement surrounding renewable energy technologies, they too are not free of environmental impacts. For example, the production of silicon for solar panels requires more than 11.36 cubic meters (3,000 gallons) of ultra pure water per 8-inch wafer, however, some say that under optimum conditions this number can be reduced by 80 percent (Yao et al., 2004). Likewise, growing dedicated energy crops for biofuels may lead to increased erosion, soil loss and loss of natural habitats. Wind turbines are well-known for their danger to birds. Finally, many forms of renewable energy generation rely on natural sources of energy, which may not have sufficient availability or reliability, either spatially or temporally, to satisfy demand.

The previous paragraphs describe only a few of the environmental impacts of different forms of energy generation; other authors have described these impacts with much greater breadth and depth. Clearly, these impacts should be considered in any decision. This analysis, however, focuses on the water required for electricity generation, with the assumption that the impacts of electricity generation on water resources are only one of many.

Non-renewable Fuels

Non-renewable fuels include coal, water used by large hydroelectric facilities (greater than 30 megawatts), nuclear (uranium), oil, and natural gas. Coal, oil, and natural gas are fossil-based fuels with finite supplies. Nuclear power is generated from uranium, which is also of finite supply. Large hydroelectric facilities are those facilities generating greater than 30 megawatts, and are not considered renewable under California's Renewable Portfolio Standard (RPS). Non-renewable fuels make up the majority of electricity generation in California, and in the world. Generation facilities using non-renewable fuels feature similar electrical generation systems and cooling technologies.

Coal

Introduction

Referred to by the Department of Energy (DOE) (USDOE, 2007a) as "the workhorse of the nation's electric power industry," coal supplies 52 percent the electricity consumed by Americans (NETL, 2001). In fact, the United States holds about 35 percent of the world's potentially extractable coal reserves (Illinois Clean Coal Institute, 2006), which surpasses the known reserves of any other nation. The Federal Energy Information Administration (EIA) reports that the U.S. has close to 500 billion tons of demonstrated reserves (extractable with current technology), while the USGS notes that the country may have as much as four trillion tons of coal resources (total coal deposits, regardless of whether they can now be mined) (USGS, 2006a). These aforementioned numbers reflect a natural resource that is plentiful, however, the conversion of this resource (coal) into useable power depends on a resource that is limited: freshwater. Over twelve cubic meters of water are needed to generate one MWh of electricity from coal (NREL, 2007a).

While coal provides a negligible share of California's in-state electricity, it is the predominant source of energy in the nation's southwest, an area marked by water scarcity. By increasing the efficiency of coal power plants, the value of each cubic meter of water required as an input to power production could be maximized. Typical thermoelectric power plants convert only a third of coal's energy potential to electricity (USDOE, 2007b), although technology is rapidly changing, and new ways of increasing production efficiency are being developed.

Generation Technology

Coal Mining and Transportation

The mining of coal requires water for cutting, washing, and dust suppression. Water is also needed for some methods of coal transportation. After coal is mined it must be transported to a power plant. Traditionally, coal was moved in solid form via truck, rail, or barge. In the last few decades slurry pipelines were built, allowing pulverized coal to be mixed with water (or oil) and then piped up to hundreds of miles away for eventual use. The U.S. has only one operational coal slurry pipeline, the Black Mesa Pipeline. The amount of water required for transportation of slurry may be reduced with new technology. A coal log fuel pipeline system being developed at the University of Missouri uses less energy and costs less than traditional slurry pipelines (Liu, 2002). Although not yet in use, these log pipelines save up to 70% of the water used in slurry pipelines while transporting the same amount of material (Liu, 2002). Solid coal is difficult to transport, thus slurry pipelines, liquefaction and gasification of solid coal have all improved transportation efficiency.

Coal Washing

Water requirements for coal mining and processing depend on the sulfur content of the coal and the fashion in which it was mined. Pyritic sulfur particles are heavier than coal itself, so it's easily removed with a blast of water. Although low-sulfur western coal needs less washing than eastern coal, it also has a lower heating value. In order to overcome the energy penalty, a larger amount of western coal must be combusted to produce the same amount of electricity as a smaller quantity of eastern coal (Chan et al., 2006), which has implications for both water and other environmental factors.

Traditional Coal Combustion

The three types of coal combustion systems are fixed bed, entrained bed, and fluidized bed.

In a fixed bed combustor lump coal is held on a grate and air passes upwards though the coal. High combustion rates are not possible with fixed bed combustors.

Entrained bed units are the most commonly seen combustion technology (Edgar, 1983) and use a feed of 3 – 6 mm coal particles. These particles are carried by the gas into the furnace size, and entrained flow gasifiers use a pulverized feed, similar to that used in pulverized coal combustion (PCC).

Fluidized bed combustion systems, the most recent of the three systems, contain upward blowing jets of air that suspend burning coal during the combustion process, allowing it to mix with limestone or dolomite, which absorb sulfur pollutants. More than 95 percent of the sulfur pollutants in coal can be captured inside the boiler by the sorbent (DOE 2006). To reduce NO_x emissions, fuel in burned at temperatures well below the threshold where nitrogen oxides form.

Gasification (Cleaner Coal)

Gasification (Figure 11) is the process in which carbon-based materials such as coal are broken down into their basic chemical constituents. When coal is gasified it is transformed into synthesis gas ("syngas") that can be used to produce cleaner electricity, transportation fuels, and chemicals efficiently and cost-effectively. The gasification of coal holds promise as an environmentally clean, affordable, and, efficient, and stable source of power to meet the nation's growing energy demands.

Gasification is the cleanest commercially available coal combustion technology, producing extremely low SO_x, NO_x, and volatile mercury emissions; and turning waste into commercially useful byproducts. Gasified coal plants are also much more efficient than traditional single cycle coal plants, using less coal to produce the same amount of energy, resulting in lower CO_2 emissions. Finally, coal gasification also makes transportation of the fuel easier (traditional pipelines can be used) and enables simpler removal of environmental contaminants such as sulfur (USDOE, 2007a). The only major disadvantage to coal gasification is the upfront cost. IGCC plants cost 20 percent more to build than conventional coal fired plants (Hopey, 2005).

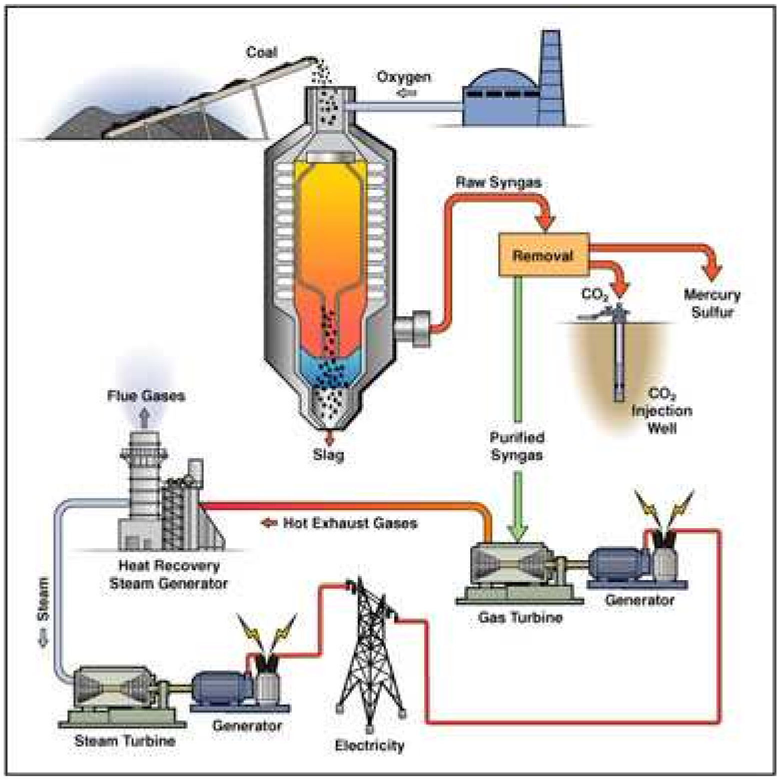


Figure 11. Gasification schematic (NRDC, 2005).

In integrated gasification combined-cycle (IGCC) systems, the syngas is cleaned of its hydrogen sulfide, ammonia, and particulate matter and is burned as fuel in a combustion turbine. The combustion turbine in turn drives an electric generator, and hot air from the combustion turbine that would ordinarily be waste heat can be channeled back to the gasifier or the air separation unit. The exhaust heat from the combustion turbine is recovered and used to boil water, creating steam for a steam turbine-generator.

The use of a combustion turbine and a steam turbine in tandem is what is known as combined cycle power generation, and results in augmented power generation efficiencies (currently 42 percent but expected to approach 60 percent in the near future) (USDOE, 2006a). Due to combined cycle generation, IGCC is the most efficient coal technology on the market, and is expected to remain so for the foreseeable future (Kramer, 2006).

Cooling Technology

A plant's cooling system is the primary determinant for its ratio of consumptive use to withdrawals. Cooling systems currently in operation for coal-powered plants are divided into two categories: once-through cooling and closed-loop, or recirculating cooling. Closed-loop cooling systems include wet cooling, hybrid wet-dry cooling, direct dry cooling, indirect dry cooling, and pond cooling. Closed-loop cooling results in larger consumptive-use values relative to withdrawals, since water that is continually removed from the system as blowdown water must be replaced.

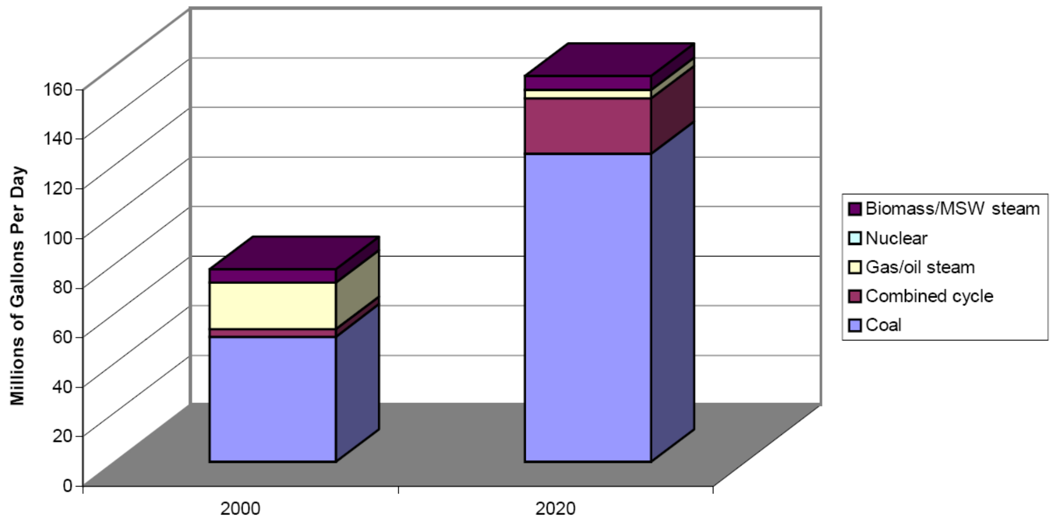


Figure 12. Power plant freshwater consumption (evaporation), by plant type, for 2000 and 2020, in the California and southern Nevada areas of NERC's WSCC region; DOE EIA AEO2000 Generation Projection (EPRI, 2002c).

Once-through Cooling

Once-through cooling (Figure 13); (Figure 14) is common in older power plants. It is the most widely used cooling technology in U.S. power plants; however, it is only used in 15 percent of plants in the arid Rocky Mountain states and Nevada, and rarely found in new facilities (Baum et al., 2003). Once-through cooling systems withdraw water from an adjacent source (either fresh or saltwater), circulate the water through heat exchangers, then return the water to a surface-water body at a higher temperature. While a small amount of cooling occurs due to conduction, convection, and thermal radiation loss, evaporation from the body of water dissipates the majority of the heat. Once-through cooling is the most commonly used type of cooling for coal power plants (Table 5), and requires greater amounts of water to be withdrawn than recirculating cooling. Water *consumption* is less with once-through cooling, however, as the withdrawn water is returned to its source, and is thus not subject to evaporation through cooling towers or ponds. Of the 515 million cubic meters (136 billion gallons) per day of freshwater used by thermoelectric generators in 2000, the

USGS estimated approximately 88 percent was used at plants with once-through cooling systems (Feeley et al., 2005).

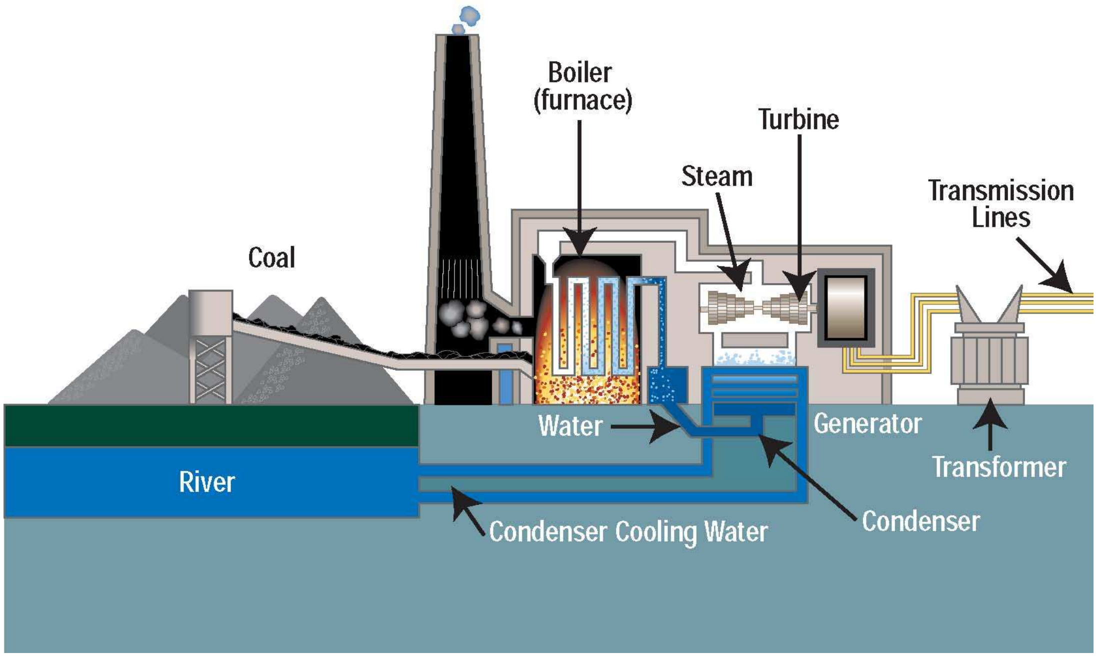


Figure 13. Once-through cooling system (Tennessee Valley Authority, 2007).

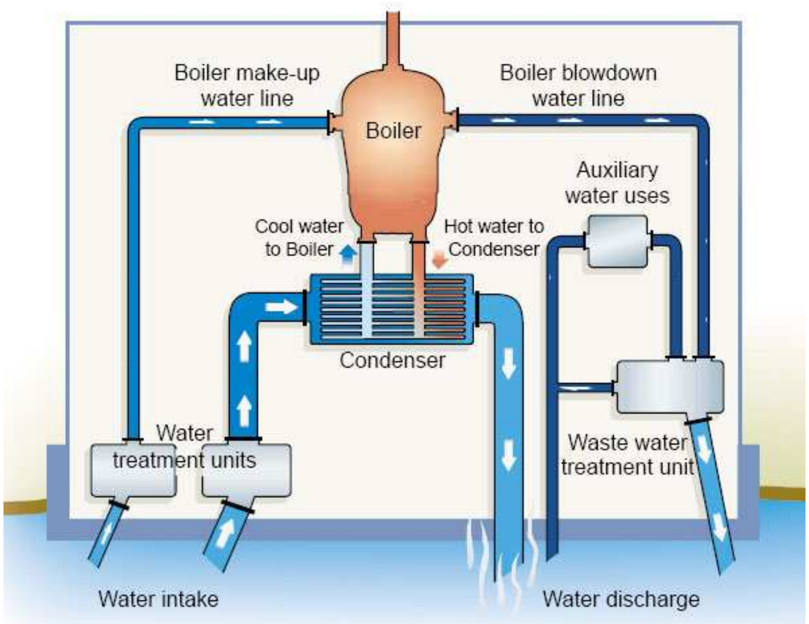


Figure 14. Detailed schematic of once-through cooling (Baum et al., 2003).

Table 5: Cooling technology by generation type (Steiegel, 2006).

Cooling Technology by Generation Type				
	Percentage (%)			
Generation Type	**Wet Recirculation**	**Once-Through**	**Dry**	**Cooling Pond**
Coal	48.0%	39.1%	0.2%	12.7%
Fossil Non-Coal	23.8%	59.2%	0.0%	17.1%
Combined Cycle	30.8%	8.6%	59.0%	1.7%
Nuclear	43.6%	38.1%	0.0%	18.3%
Total	41.9%	42.7%	0.9%	14.5%

Recirculating Cooling

Closed-cycle cooling systems consume more water than once-through systems; evaporative rates for these systems are 40 percent more than for once-through systems.

In the dry western states, 85 percent of cooling is done by recirculating, or "closed-loop" systems, which includes both wet cooling and dry cooling (Baum et al., 2003). Recirculating systems (Figure 15) recycle water by passing it through a wet cooling tower, dry cooling tower, hybrid system, canal system, or cooling pond. Some of the water evaporates, but most goes through a filler material that brings the water temperature back down to be used again for cooling.

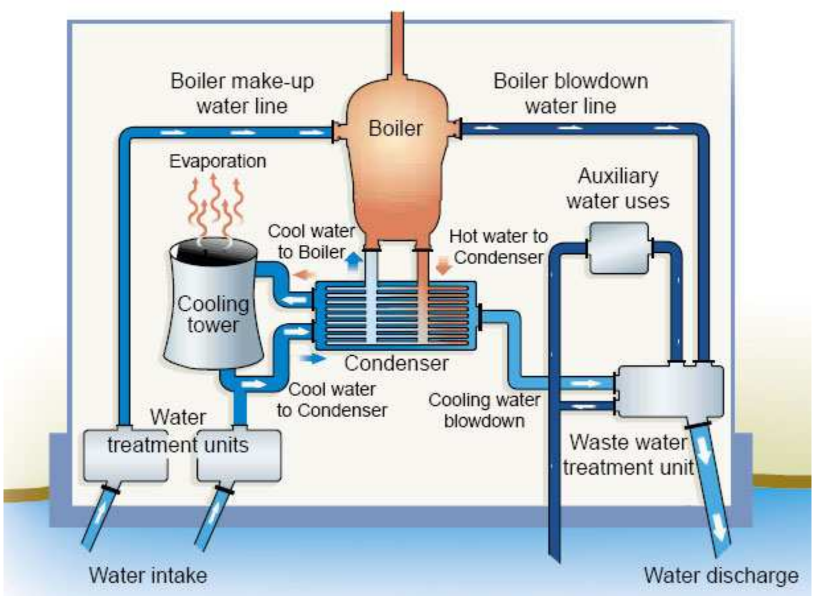


Figure 15. Recirculating wet cooling with the use of cooling towers (Baum et al., 2003).

Although power plants that recirculate cooling water withdraw water at a lower rate than do once-through cooling plants, these plants have higher *consumptive* water use due to water loss from evaporation, blowdown, drift, and leakage. Additional water, called makeup water, must be continually withdrawn from the plant's raw water supply to make up for these losses. Blowdown losses alone range from 4 – 8 percent of boiler feedwater flow rate, they can be as high as 20 percent is the feedwater is of poor quality (North Carolina Department of Environment and Natural Resources, 2004). The Nuclear Regulatory Commission (NRC) estimates that closed-cycle systems withdraw only five to ten percent as much as once-through cooling systems, while they consume up to twice as much water per MWh of electricity produced as a once-through cooling system (Gleick, 1994); (Baum et al., 2003).

Wet Cooling

In a wet cooling system, the condenser is cooled with water recirculated through a cooling tower. Heat is transferred directly via an air/water interface, and the steam is evaporated into the atmosphere. In addition to steam water loss, water is lost as blowdown water is discharged. Recirculating wet cooling systems consume more than ten times the amount of water as do once-through cooling systems partially due to the discharge of blowdown water (Table 6).

Table 6. Average cooling system water use and consumption (Feeley et al., 2005).

Average Cooling System Water Use and Consumption		
	Average m^3/kWh	
Type of Cooling Water System	Water Withdrawal	Water Consumption
Once-Through	142.69	0.38
Recirculating Wet	4.54	4.16

Dry Cooling (Direct and Indirect)

Dry cooling systems (Figure 16) are used for power plants in arid areas. Instead of cool water, outside air is used to cool down the steam created from fossil fuel combustion (Baum et al., 2003). Only one major U.S. coal-fired power plant is dry cooled (Feeley et al., 2006), and no nuclear plants employ dry cooling technology. The lack of dry cooled plants in the U.S. is likely due to increased capital costs and the associated energy penalty. In regards to cost, a 500MW gas-fired combined-cycle plant using dry cooling costs approximately $8 million to $27 million more than a wet cooled plant, which is about 5 – 15 percent of the total plant cost (Maulbetsch & DiFilippo., 2006). In regards to energy output, The EPA reports that, "for coal-fired plants, the mean annual energy penalty (averaged across climates) is 8.6 percent for dry cooling compared to once-through systems, and 6.9 percent for wet cooling compared to once-through systems" (EPA, 2001).

Dry cooled systems enclose the condenser coolant within a piping network, eliminating the direct air/water interface found in wet cooling systems. Heat transfer is based on the dry bulb temperature of the air and the thermal transport properties of the piping material. While water loss is less for dry cooling towers than wet cooling towers, some make-up water is still required. Dry cooling requires four to six times the power as wet cooling (EPRI, 2002a), and cooling efficiency is lower for dry cooling systems than wet cooling towers due to the higher dry bulb temperatures.

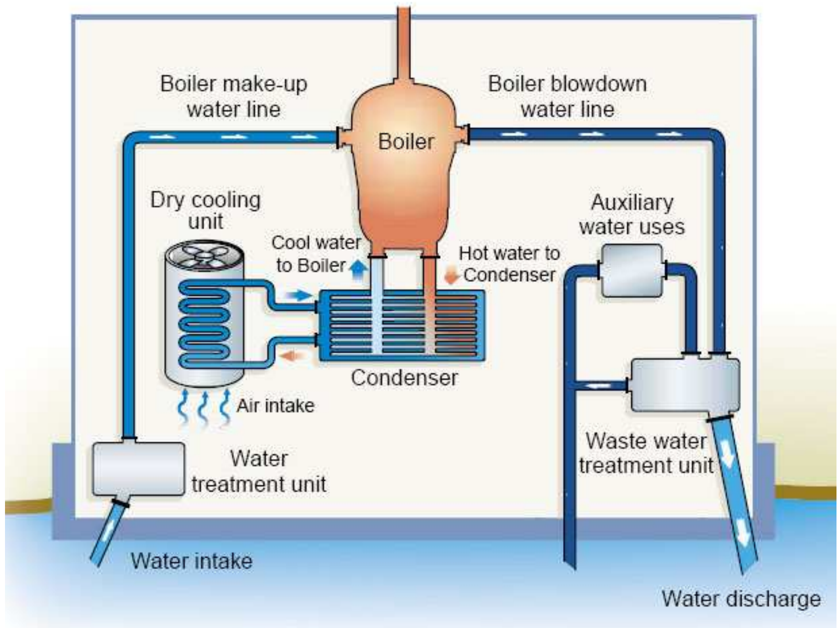


Figure 16. Dry cooling system (Baum et al., 2003).

The difference between direct and indirect dry cooling systems is that direct systems duct the steam to *air*-cooled condensers while indirect systems condense the steam in *water*-cooled surface condensers where a hot liquid such as condenser coolant rejects heat to the atmosphere without the evaporation of water. The heated water is then pumped to air-cooled heat exchangers and cooled using a large diameter fans that blows air across a finned tube heat exchanger (EPRI, 2002a). Indirect dry cooling systems are used as retrofits for once-through and wet cooled systems (EPRI, 2002a).

Although dry cooling consumes up to 95 percent less water than once-through and recirculating systems by eliminating the need for steam condensation (EPRI, 2002a), an energy penalty occurs when dry cooling is implemented. An energy penalty, as defined by Burns and Micheletti (2000), is "the loss of electricity generating capacity incurred when a cooling system is unable to perform at design efficiency". In short, implementing dry cooling means that less energy is produced for the same amount of fuel.

Maulbetsch and DiFilippo (2006) have calculated that a 500 MW combined cycle plant with a dry cooling system uses less than 5 percent of the water used in a similar plant with a wet cooling system. Dry cooling systems, however, are more costly; a dry cooling system increases the capital cost of a typical power plant by approximately $18.1 million (Maulbetsch & DiFilippo, 2006). Baum et al. (2003) estimates costs for a 700 MW plant to be 6 cents/kWh for a wet cooling system, and 25 cents/kWh for a dry cooling system. It also reports that only about fifty plants nationwide totaling 60 MW of installed capacity take advantage of dry cooling technology, but this number is growing.

Hybrid Wet-Dry Cooling

Hybrid cooling technology offers an emergent middle-ground option between wet and dry cooling systems where wet and dry cooling components can be used either separately or simultaneously. One type of hybrid system sprays water instead of using only air to cool the steam; the other system alternates between wet and dry cooling depending on the available supply of water (Baum et al., 2003). Depending on system configuration, water consumption can be 30 to 98 percent less than that of wet recirculating systems (EPRI, 2002a).

Cooling Ponds

Cooling ponds are an alternative to cooling towers wherein hot water from plants is pumped into the ponds and sent back to the plant to recirculate once the water has cooled. Cooling ponds lose water through evaporation; the amount of water evaporated depends on the size of the pond, the ambient air temperature, and the temperature of the power plant discharge.

Water Requirements

In the most basic sense, water is needed by power plants in the form of steam in order to spin turbines and generate electricity. In recirculating plants this water accumulates undesired suspended and dissolved solids as it flows repeatedly through the boiler, condenser, and cooling tower systems. This water becomes a blowdown stream, and must be periodically replaced with makeup water to maintain high levels of water quality.

Although cooling systems demand the greatest quantities of water, there are many other important uses for water at fossil fuel power plants. Plants use water for the operation of pollution control devices such as flue gas desulfurization (FGD) technology, as well as for ash handling, wastewater treatment, syngas humidification, system make-up, and wash water (Feeley et al., 2005).

California Perspective

The coupling of California's Renewable Portfolio Standards (mandating 20 percent renewable energy by 2010) and the recently passed AB 32, California is expected to decrease its reliance on coal. Although there are no major in-state coal plants that are selling energy to utilities, California imports 723,000 short tons of coal for electricity generation each year from out-of-state sources (Energy Information Administration, 2006b).

Opportunities for Water Input Reduction and Non-Potable Water Use

Given limited freshwater supplies and growing energy demand, there is an undeniable need for the development of technologies that produce power using less (or lower quality) water. In some cases, systems have been designed that downcycle water from one process to another. For example, blowdown streams can be combined with gasifier slag and reused as coal slurry water.

In the case of IGCC, the water used to slurry the feed coal to the gasifier does not need to be of high quality, as impurities in the water are removed along with the coal ash in the gasifier slag. Boiler feed water, however, must be of high quality in order to prevent scale deposition in boilers, thus make-up water to the boiler feed system must be treated and the cost of treatment increases as the quality of the raw water decreases. In general, the lower the quality of water input to the system, the more money and energy that will have to be spent treating it.

Plants such as Burbank Water and Power treat and recycle their blowdown water by separating out the salts from the water. This is a process known as zero liquid discharge, or ZLD. Zero Liquid Discharge systems eliminate the liquid waste stream from a plant by reclaiming high purity water for reuse. In many cases, plant water consumption can be reduced from 10 – 90 percent with the addition of a ZLD system, minimizing the potential risk associated with plant waste streams and improving unfavorable public perceptions of new facilities. In areas of acute water shortage, ZLD design can help optimize the overall facility life cycle costs (GE, 2007).

A handful of universities are currently conducting research into ways to minimize freshwater withdrawals required for thermoelectric power generation. The National Mine Land Reclamation Center at West Virginia University is assessing the feasibility of using mine water (as opposed to freshwater) to generate power (Anna, 2005). The University of Pittsburgh is investigating the use of secondary treated municipal wastewater, passively treated wastewater, passively treated coal mine drainage, and ash pond effluent as cooling water (Anna, 2005). Other universities are researching the use of condensing heat exchangers to recover water from boiler flue gas, innovative cooling tower condensing technologies, and scale-prevention technologies (which will allow water to be recirculated more times before being blown down).

Environmental Impacts

Coal power, however inexpensive, does not come without its hidden costs. Many of these costs are environmental. In regards to global warming, The International Energy Agency (2001) notes that in 1999, the source of 38.2 percent of the world's CO_2 emissions, and 31 percent of U.S. CO_2 emissions, was coal burning plants. Coal also contributes to acid rain, with 60 percent of U.S. SO_2 emissions coming from coal-burning plants (International Energy Agency, 2001). Other environmental effects attributable to coal are as follows:

- Acid mine drainage.
- Groundwater contamination from slurry impoundments
- Smog
- Communities near coal powered plants face higher rates of asthma and air pollution
- Thermal pollution in bodies of water
- Mercury Pollution

Hydroelectric Power

Introduction

Hydroelectric power is perhaps the most vivid connection between energy and water. Today, approximately 19 percent of the world's electricity is generated by hydroelectric facilities (World Commission on Dams, 2000). As water flows under the force of gravity, hydroelectric facilities harness the energy, generating electricity. While hydroelectric generation relies on surface water, an essentially renewable resource, large hydroelectric facilities have substantial environmental impacts. These impacts include altering natural flows and displacing native wildlife. In addition, some studies have shown that reservoirs release substantial amounts of greenhouse gases as organic matter biodegrades under anaerobic conditions. In the Western U.S., most economically viable hydroelectric power has already been tapped, and, for the environmental reasons cited above, California's RPS excludes large hydroelectric facilities.

Generation Technology

Hydroelectric power is generated as flowing water turns turbines, driving a generator. Dams create a height differential or "head" between the reservoir surface (behind the dam) and the streambed (below the dam). As the water falls, often through penstocks, it turns a turbine, generating power. Several types of facilities may be used to generate hydropower; these include run-of-river dams, where the natural flow of water drives the turbine, pumped-storage facilities, and man-made structures such as aqueducts, canals, or pipelines.

Hydroelectric generation capacity fluctuates, both seasonally and daily. Hydroelectric facilities can be used to respond quickly to peak demands of energy and have a strong ability to bear load capacity. In the western U.S., reservoirs capture springtime snowmelt and runoff; the subsequent summertime releases and energy generation coincides with peak summer demands. Hydroelectric facilities may also be used to respond to daily fluctuations in demand: pumped-storage facilities are often paired with thermo-electric generators, which pump water to a higher elevation storage facility during off peak hours. During peak demand hours, this water is released, generating load-carrying electricity.

Water Requirements

Hydroelectric generation requires substantial amounts of water. All water that passes through a facility's turbines is considered "withdrawn water." "Consumed water," or water that leaves the system entirely, primarily refers to any water that evaporates from the surface of the reservoir. Any other losses of water in hydroelectric generation are negligible. In the United States, annual evaporation from reservoirs ranges from 0.5 to 2 meters (depth from the reservoir surface), with the lowest rates in the Northeast, and highest rates in the arid Southwest. In the western seventeen states, approximately 1.1 meters evaporate from reservoir surfaces annually, totaling 15.2 billion cubic meters (Gleick, 1992). In California, however, rates of evaporation relative to power generation are approximately one third of the national average (Inhaber, 2004).

The quantity of water consumed by hydroelectric generation (per unit of energy generated) varies by up to several orders of magnitude, and is affected by several factors. The size of the facility and the degree of hydraulic head play the most substantial role: a high ratio of reservoir surface area to hydraulic head typically results in high rates of evaporation relative to the energy generated. Facilities with a large hydraulic head, therefore, typically have lower rates of consumption. Additional factors affecting rates of evaporation include reservoir location and size, local topography, dam type, and climate (both temperature and wind patterns) (Inhaber, 2004).

Assumptions and Limitations

Several important caveats accompany the preceding analysis. First and foremost, many hydroelectric facilities serve multiple purposes, including flood control, recreation, and as a source of municipal or irrigation water. Often, hydroelectric generation may be a secondary goal; for example, turbines were constructed in the Diamond Springs facility (California) in response to the energy crisis in 2000 - 2001 (O'Hagan, 2006). Secondly, while hydropower is not sensitive to or dependent on outside fuel costs, it is highly sensitive to both rates and patterns of annual precipitation. As described above, many reservoirs serve multiple purposes. In facilities where the primary purpose is flood control, reservoir managers may be required to release water during off peak hours or seasons, reducing hydropower generation potential. Similarly, irrigation demands, storage requirements, and environmental regulations may limit the volume of water released.

The California Perspective

In California and the western U.S. in general, potential for new, large hydroelectric facilities is extremely limited for several reasons (California Energy Commission, 2005a). Dams and reservoirs often have negative environmental consequences, most notably for native flora and fauna. In addition, most ideal sites (from an economic perspective) have already been developed[5]; high capital costs and strict environmental regulation make new construction unlikely. Secondly, large hydroelectric facilities do not qualify as renewable energy sources under the California RPS. Specifically, the RPS includes new facilities with a capacity less than 30 MW and other existing hydropower facilities that are re-powered, up to 30 MW (California Energy Commission and PIER, 2006). Therefore, new hydropower facilities in California will likely be limited to those that do not require any additional water appropriations or diversions (most likely developed in man-made conduits such as aqueducts, canals, and pipelines) (California Energy Commission and PIER, 2006). Of these undeveloped potential sites, most are located in the southern part of the state, where there are large municipal utilities and significant irrigation deliveries.

[5] The U.S. Department of Energy Hydropower Program has identified 5,677 sites with undeveloped hydropower potential. If developed, these sites would have a capacity of approximately 30,000 MW, equal to 40 percent of existing hydroelectric generating capacity (U.S. Bureau of Reclamation, 2005).

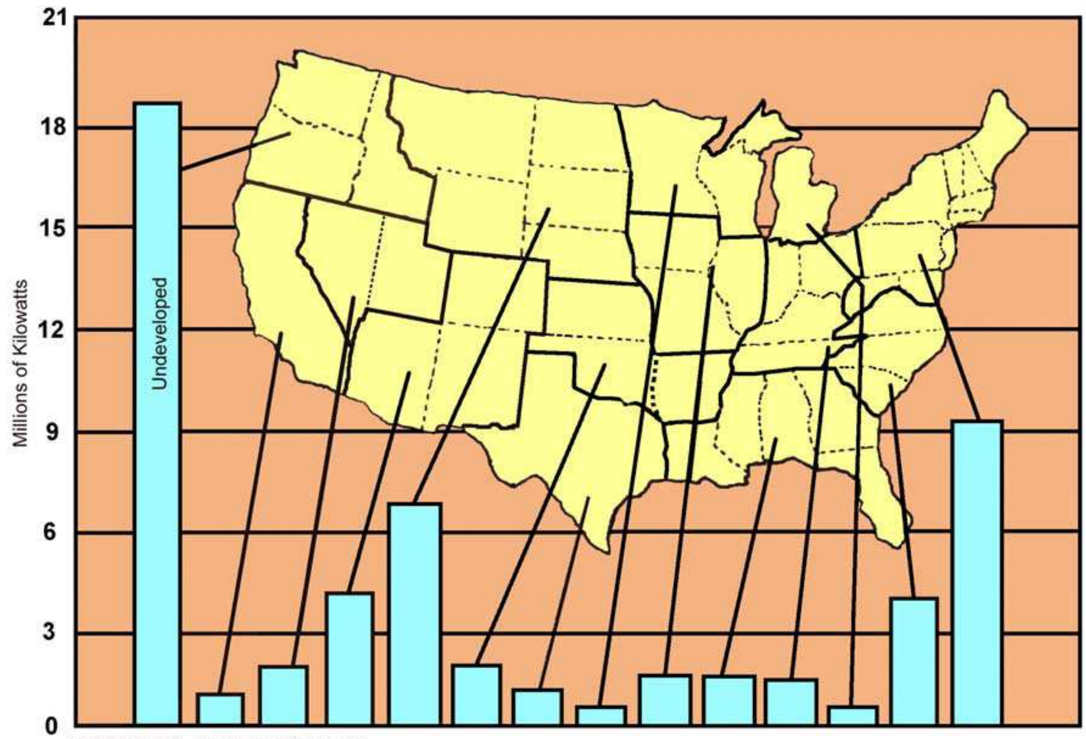


Figure 17. Undeveloped hydroelectric power in the United States (U.S. Bureau of Reclamation, 2005).

Environmental Impacts

While hydroelectric power represents an essentially renewable resource, it has been excluded from California's RPS for its negative environmental effects. Hydroelectric dams and their accompanying reservoirs have a clear impact on both flora and fauna, and in some environments, may contribute significant greenhouse gas emissions. Dams act as barriers to migration of fish and other fauna, altering the natural exchange of nutrients between upper and lower portions of watersheds. In addition, by changing flow regimes, they may negatively impact native species, allowing invasive species to prosper. Dams capture sediment, altering patterns of erosion and deposition both downstream and upstream of the facility. Finally, the creation of reservoirs inundates living, organic matter; the anaerobic decomposition of this matter and other organic matter delivered to the reservoir generates methane, a potent greenhouse gas (GHG). Under some circumstances (notably shallow, tropical reservoirs), GHG emissions are comparable to those of natural gas facilities (McCully, 2006).

Nuclear Power

Introduction

There are 64 nuclear power plants with 104 nuclear reactors in operation in the United States providing approximately 19 percent[6] of the U.S.'s energy (USDOE - EIA, 2006a). Worldwide, there are 442 nuclear power plants in operation. This provides 16 percent of the global electrical demand (World Nuclear Association, 2006). The United States, the largest nuclear power producing country, produces approximately 30 percent of the world's nuclear power[7] (USDOE - EIA, 2007b). Nuclear plants range in thermal efficiency depending on enrichment level, reactor type, and plant design; efficiencies range from 31 to 40 percent (Gleick, 1994; USDOE - EIA, 2004).

Generation Technology

Electricity is generated from nuclear power via nuclear fission. The fission process produces heat which in turn heats water, boiling it, and generating steam. Similar to most fossil-fuel based plants, the steam turns a turbine, producing electricity. In the U.S., two types of light water reactors are in operation: boiling water reactors (BWR) and pressurized water reactors (PWR) (USDOE - EIA, 2006a). The reactors operate similarly, except for one major difference: the PWRs heat the water under pressure (Figure 18; Figure 19). Also in operation outside the U.S. are pressurized heavy water reactors (PHWR), advanced boiling water reactors (ABWR), fast breeder reactors (FBR), light-water-cooled graphite-moderated reactors (LWGR or RBMK), gas-cooled reactors (GCR), advanced gas-cooled reactors (AGR), and water cooled water moderated power reactors (WWER). The majority of reactors currently in operation and under construction, however, are BWRs and PWRs. Alternative types of facilities, such as high temperature gas-cooled reactors (HTGR) and sodium cooled reactors, are being researched, but they are not available for commercial applications as of the date of this analysis.

[6] Based on 2005 electricity generation data
[7] Based on 2005 data energy data

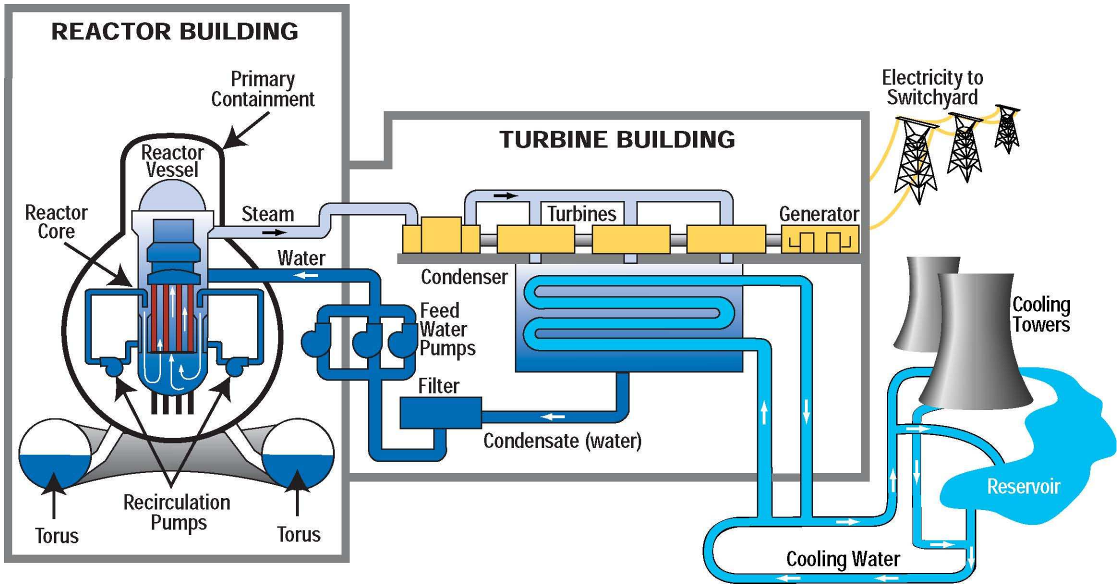


Figure 18. Boiling water reactor (Tennessee Valley Authority, 2007).

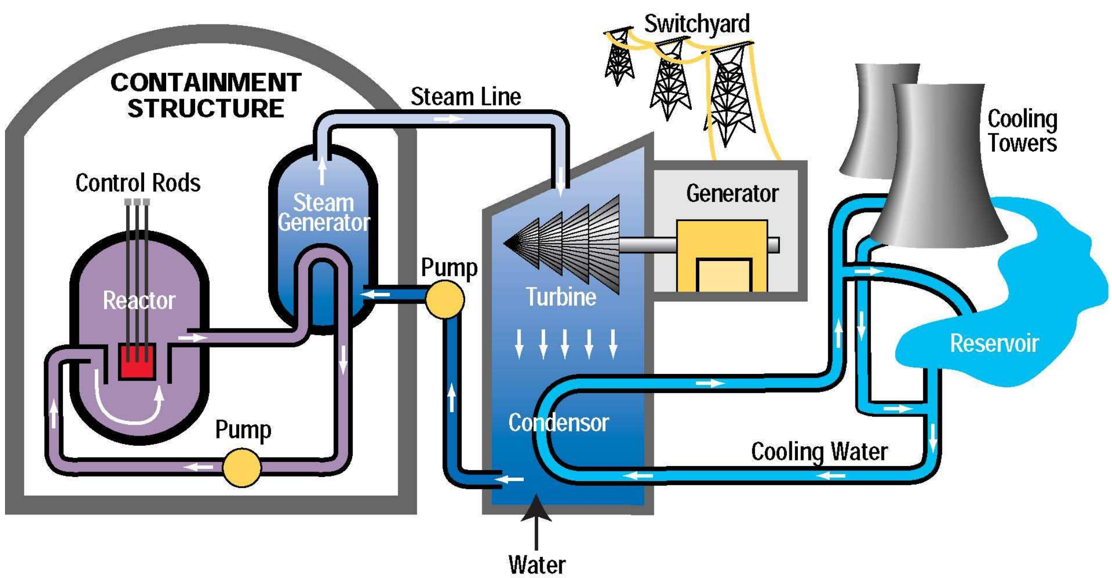


Figure 19. Pressurized water reactor (Tennessee Valley Authority, 2007).

The primary fuel for the fission process is Uranium-235. Uranium is mined from open pits, underground mines, and in-situ leaching (ISL). Over half of the world's uranium now comes from underground mines, with the remainder coming from open cut mines (27 percent) and ISL (20 percent) (World Nuclear Association, 2006). The U.S. has nine uranium mines, three underground and six ISL mines[8] (NEI, 2007b);

[8] As of 2004.

the majority of the world's uranium, however, is from foreign mines (USDOE - EIA, 2006d).

Water Requirements

Power plant cooling represents the greatest use of water in the production of electricity from nuclear power. The amount of water used and consumed varies, depending on the plant's cooling equipment type. Nuclear plants may be cooled via closed-cycle and once-through systems. Closed cycle systems include mechanical draft cooling towers, natural draft cooling towers, canal systems, and cooling lakes. For more information on these systems, please see the coal cooling section of the document.

Mining of nuclear fuel also uses significant amounts of water. Depending on the type of mining, uranium mining may require water for dust control, ore beneficiation, and revegetation of mined surfaces (Gleick, 1994). When uranium is mined in open pits, the mining process requires approximately the same amount of water as the surface mining of coal (Gleick, 1993). In-situ leach (ISL), the dominant process used in the U.S., uses less water than open pit or underground mining. Unlike open pit and underground mining, which bring the rock to the surface, ISL leaves the ore in the ground. To retrieve the minerals, solvents are pumped through the deposit, leaching and mobilizing minerals (Hore-Lacy, 2003). Subsequently, this uranium-rich solution is pumped out of the ground, along with groundwater. Once the ore is separated out (by solvent extraction or ion exchange) most of the water is pumped back into the ground, resulting in almost no net consumption of water. Some, however, consider this groundwater "consumed" due to its low quality.

The processing of the uranium includes several steps. These steps include milling, refining, and enriching the uranium, all of which consume water. The milling and enriching of uranium consumes water primarily through evaporation from tailings ponds and evaporative cooling (Gleick, 1994). The amount of water required varies, depending on the enrichment process. For example, centrifuge separation requires considerably less water than the most common form of enrichment, gaseous diffusion (Gleick, 1993). Additionally, the processing of uranium is very energy intensive, which, in turn, requires large amounts of water to produce said energy.

Assumptions and Limitations

Nuclear power's main limitation is in increased generation, both from new and current plants. A new nuclear power plant has not come online in the U.S. since 1996 (USDOE - EIA, 2004), and while three early site permits were filed in 2003, they were for reactors at existing plants (NEI, 2007a). Additionally, the permits may be "banked" for later use at that site and then apply for a construction and operating license at that later time. Also, while the amount of electricity generated from nuclear power in the U.S. has increased due to increasing capacity factor[9], the proportion of electricity generated, even with a continued increase in capacity factor is expected to decline from nuclear's current share of 19 percent nationally to 15 percent in 2030 (USDOE - EIA, 2006a).

The California Perspective

California currently has two nuclear power plants, Diablo Canyon near San Luis Obispo and San Onofre near San Diego, each with two reactors in operation. Both of the reactors at both plants are pressurized water reactors (PWR). Additionally, both plants are once-through cooled, taking advantage of their location along the California coast and ocean water supply (NRC, 1996). In 2005, they produced 14.5 percent of California's electricity (California Energy Commission, 2007a).

Diablo Canyon's first reactor was initially licensed in 1984 and is approved to continue operating until 2021. The facility's second reactor was initially licensed to operate in 1985 and will not expire until 2025. San Onofre's two operating reactors also were first issued operating licenses in 1982 and 1983; licenses for both will expire in 2022 (NRC, 2006a). Reactor operation licenses can be renewed, and virtually all U.S. reactors are expected to apply for license renewals (NEI, 2007a). Thus, any of the reactors could operate beyond the current license expiration dates. California's unfavorable political climate and the high cost of nuclear power plants, however, make additional plants unlikely. No intentions or plans for future nuclear plants in California have been announced or filed with the Nuclear Regulatory Commission (USDOE - EIA, 2006b).

Opportunities for Non-Potable Water Use

Nuclear plants currently use large amounts of water for cooling and are typically located next to bodies of water. Water supply, as a result, has not been a concern in the past. As our understanding of the environmental impacts of water consumption increases, future high consumptive uses will become more difficult to establish. Located in a severely water-limited region, the Palo Verde Nuclear Generating Station near Phoenix, Arizona uses treated sewage effluent from the Phoenix City Treatment Plant for its cooling water needs (APS, 2007). Other uses of non-potable water in nuclear power generation could be applied from other thermoelectric generation technologies, such as natural gas and oil-fire combined cycle, which are also able to use treated wastewater (EPRI, 2002b).

Environmental Impacts

Nuclear power plants have a variety of environmental impacts. A large amount of land is needed for the siting of a nuclear power plant. For example, the William B.

[9] Capacity factor has increased from roughly 50 percent in 1973 to almost 90 percent in 2005 (EIA 2005).

McGuire nuclear power plant in North Carolina occupies 30,000 acres, the most land of any of the U.S. nuclear plants. The average land use, however, of U.S. nuclear plants is just less than 3,000 acres. Additionally, cooling water intakes and outflows have numerous associated environmental concerns: most notably, entrainment and impingement often have deadly consequences for aquatic organisms. Entrainment occurs when the forced influx of water brings aquatic life into the cooling system through the cooling water intake screen. As fish or other aquatic life are caught against the cooling water intake screens (due to the force of water intake), they become impinged. Additionally, the outflow water is often at an elevated temperature, which may negatively affect aquatic life. Prominent environmental concerns also include possible contamination of outflow water and larger scale incidents such as Three Mile Island or Chernobyl. Nuclear power plants offer some environmental benefits, too: nuclear facilities generate fewer emissions, such as NO_x, SO_2, CO_2 or other greenhouse gases, than fossil fuel electrical generation. As environmental concerns around global warming increase, nuclear power's low emissions and high reliability make it a more favorable choice.

Oil and Natural Gas

Introduction

Oil is extracted as crude oil, which must then be refined into different forms of liquid fuel. Energetics (1998) reports that 6.8 percent of one barrel of crude oil is refined into residual fuel oil, the type of oil used for electricity production.

Natural gas is produced in two basic forms. Associated gas is gas that is extracted along with crude oil, while non-associated gas is produced from gas fields that do not produce any crude oil (California Energy Commission, 2005c). After it is extracted, natural gas must be treated to remove impurities such as hydrogen sulfide, helium, carbon dioxide, hydrocarbons, and moisture (EPA, 2007b).

Figure 20 shows the oil and natural gas fields found in the United States:

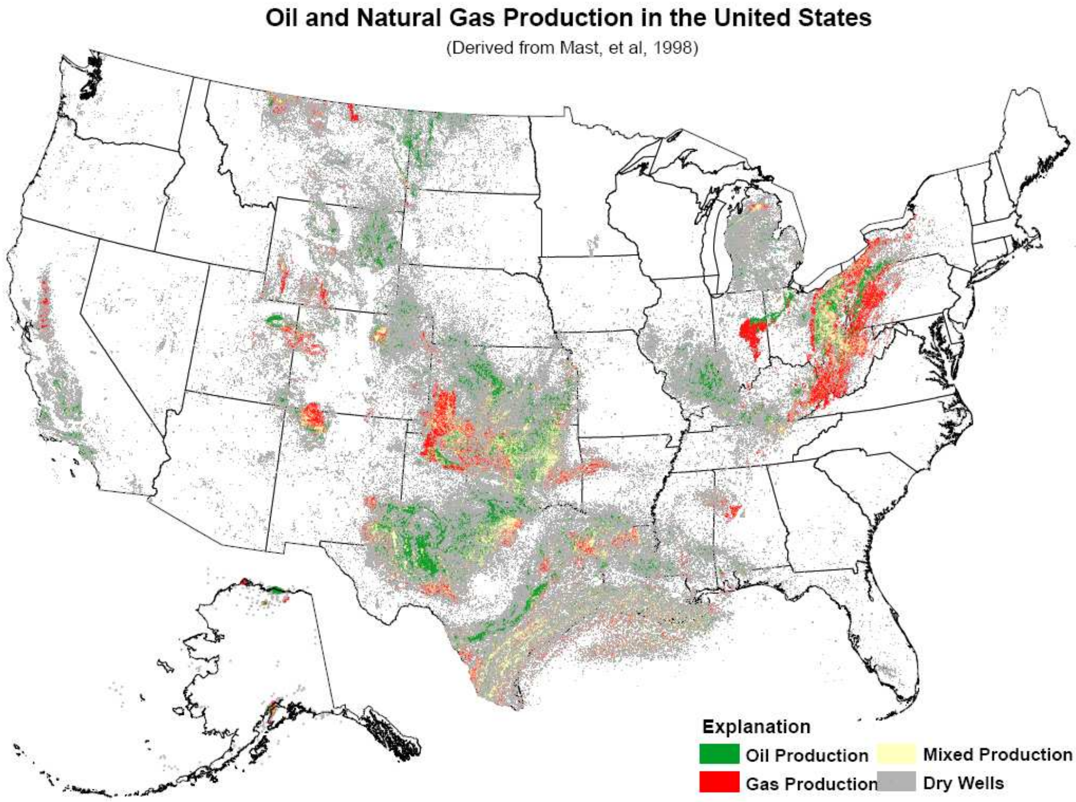


Figure 20. Map of oil and natural gas production in the United States (USGS, 2006b).

Generation Technology

In older units, steam turbines are used to generate electricity from natural gas. The combustion of the natural gas converts water into steam or vapor, which drives a turbine. Typically, newer plants make use of combined-cycle technology. In a combined-cycle plant, the combustion of gas in itself drives a turbine. This combustion process yields exhaust gases at a temperature of over 900°F (482°C), which are collected to heat water in a boiler, or heat recovery steam generator (HRSG) as shown in Figure 21. This high-pressure steam is used to drive a second turbine. With this method, the conversion efficiency (from thermal energy to electrical energy) is doubled from 30 to 60 percent (U.S. Army Corps of Engineers, 1984); (Energy Solutions Center).

The other type of natural gas plant in operation is the simple cycle gas plant, which consists of only the gas combustion turbine and not the steam-driven turbine. Although this type of plant is relatively inexpensive to build and operate, its disadvantage is the higher Btu of fuel required to produce electricity, or "high heat rate." Simple cycle plants require 9815 Btu/kWh, compared to 6795 Btu/kWh for combined cycle plants with dry cooling systems. This limits the use of simple cycle plants to only a few hundred hours per year, typically to meet peak demand or emergency conditions (Schleede, 2003); (Maulbetsch & DiFilippo, 2006).

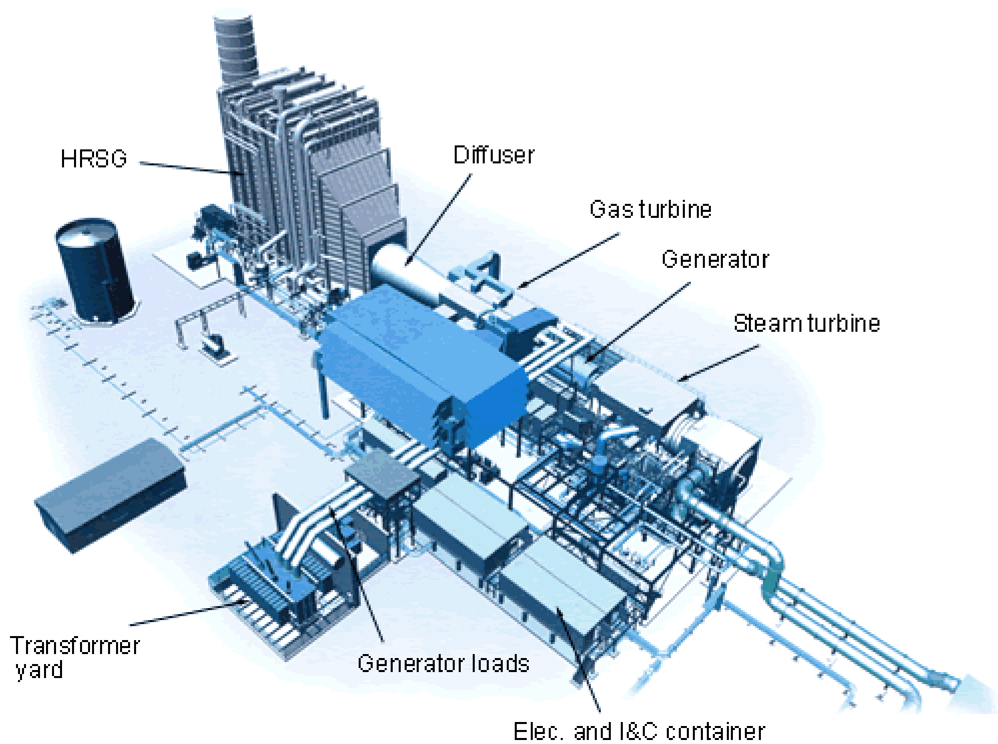


Figure 21. Schematic of a combined cycle gas power plant (Energy Solutions Center).

Cooling Technology

Oil and natural gas power plants use the same thermoelectric cooling technologies as coal plants. More information about these cooling systems can be found under the Cooling Technology discussion located in the Coal section of this document.

Water Requirements

The primary use of water in the conversion of natural gas and oil to electrical energy is for cooling. Cooling water requirements are comparable to those for coal and the methods are discussed at length in the Coal section as referenced above.

Extraction and refining of oil also consume water. About 0.011 to 32.04 m^3 of water are required to extract the equivalent of one MWh of electricity from oil. This range varies greatly because there are numerous methods of enhancing oil extraction, with techniques such as steam injection and the use of micellar polymer greatly increasing the water required (Gleick, 1994).

After the oil is extracted, about 0.09 to 0.432 m^3 of water are required to refine one MWh equivalent of crude oil for electricity generation. Higher amounts of water are required if hydrogen from dissociated water is used to improve the quality of the oil (Gleick, 1994).

A very negligible amount of water is required for the extraction of natural gas; however, water is required for the transportation of natural gas by way of pipelines. About 0.0108 cubic meters of water is required to transport one MWh of gas power (Gleick, 1994).

Assumptions and Limitations

Unlike with nuclear power, there is currently not a forceful political and social sentiment against the construction of natural gas power plants. This may change, however, with the implementation of recent California legislation addressing greenhouse gas emissions, such as AB 32. See Climate Change Policies for more information.

Progress is being made in increasing the efficiency of natural gas plants. For our analysis, we assume that older plants operate at 36 percent conversion efficiency (Gleick, 1994), and that the newer combined-cycle plants have conversion efficiencies of 60 percent (Oman, 1996). This is considerably higher than that of renewable electricity generation facilities. For this reason, we believe that natural gas facilities will continue to be built and will likely remain an important portion of California's electricity supply. Another reason is that natural gas combustion, in general, yields lower levels of air pollutants than coal combustion. See The California Perspective, Environmental Impacts, and Renewable Energy for more information.

The California Perspective

In California, most oil is found in the southern part of the state, while most gas is found in the north. Almost all natural gas produced in Northern California is non-associated gas, constituting about 21 percent of total California production. In 2004, offshore production made up 11 percent of California's total gas production (California Energy Commission, 2005c).

In 1982, about 70 percent of California's electrical generation was from combustion of oil (Kimble et al., 1982). Electricity from oil continues to be common in states such as Hawaii, Florida, Massachusetts, Alaska, and New York, which produced 81, 17, 16, 14, and 8 percent of their electricity from oil in 2002, respectively. In contrast, only 1.06 percent of California's total electricity generation was produced from oil in 2002 (Schleede, 2004). Currently only two operational oil-fired power plants exist in California, located in Los Angeles and in Santa Barbara. Both are operated by Southern California Edison (California Energy Commission, 2006a).

Today, natural gas plants are much more prevalent in California. There were 351 natural gas plants operating in 35 counties in the state in 2006 (California Energy Commission, 2006a). In 2005, about 96,088 GWh, or about 37 percent of the electricity used in California, was produced by natural gas plants. Of this amount, about 11.6 percent was imported from other states (California Energy Commission, 2006c).

Natural gas will likely remain an important source of electricity for the future of California. Despite the characterization of natural gas as a fossil fuel, it has a relatively low impact on atmospheric pollution, combined with a relatively high efficiency of energy conversion (Gleick, 1994).

Opportunities for Non-Potable Water Use

Brackish, saline, and reclaimed water is now used for cooling of newer combined-cycle plants with the use of technologies such as HERO-Crystallizer and Evaporator-Crystallizer (Maulbetsch & DiFilippo, 2006); (Owen, 2007). HERO (high-efficiency reverse osmosis) passes water through a membrane under high pressure and high pH to filter up to 90 percent of ions out. Evaporators, also known as brine concentrators, are an alternative to HERO. Evaporators take wastewater into vertical tubes that gradually evaporate the wastewater and create a positive feedback loop for further evaporation. This requires 85-95 kWh for every 1000 gallons of wastewater (Maulbetsch & DiFilippo, 2006).

Water untreated by HERO, or brine from the evaporator, is taken to crystallizers, which concentrate the water to 35-65 percent solids and require 200-300 kWh to evaporate 1000 gallons (3.785 m^3) of water not treated by HERO. Although the costs of these technologies are high, they do not offset the much higher cost of dry cooling systems compared to that of wet cooling systems (Maulbetsch & DiFilippo, 2006).

Environmental Impacts

Air impacts

Both the combustion of natural gas and oil yield nitrogen oxides and carbon dioxide. Natural gas, however, has the advantage of not having the sulfur dioxide, mercury, or fly ash emissions of oil plants. Another advantage is that natural gas emits lower amounts of nitrogen oxides and carbon dioxide than oil or coal plants. Unfortunately, natural gas emits methane, as incomplete combustion, leaks, and transport accidents can release the potent greenhouse gas into the atmosphere (EPA, 2007b); (EPA, 2007c). Table 7 compares the air emissions of coal, oil, and natural gas plants. The drilling and refining of oil also contribute to air pollution, greenhouse gas emissions, and toxic waste (Power Scorecard, 2000).

Table 7. Comparison of air emissions between coal, oil, and natural gas plants, in kilograms per MWh produced in 1991 (Reed & Renner, 1995).

	Carbon dioxide	Sulfur oxides	Nitrogen oxides
Coal	990	9.23	3.66
Petroleum	839	4.95	1.75
Natural gas	540	N/A	1.93

Water impacts

As discussed above, the cooling mechanisms found in natural gas and oil plants require a great deal of water. As a result, the populations of fish and other aquatic life can be diminished, which in turn affects industry (EPA, 2007b); (EPA, 2007c). Oil and gas plants also cause water pollution. Water within the power plant that is too hot or polluted must be released into the environment before it damages the plant itself. In general, the water flowing out of an oil or gas plant is warmer and more contaminated, even if it is treated (EPA, 2007b); (EPA, 2007c).

Land impacts

The facilities required to extract and refine oil and natural gas often occupy land inhabited by wildlife, and can also damage soil and cause landslides and erosion. Refineries and power plants also generate a great deal of sludge and other wastes that can contaminate land if not properly handled (Power Scorecard, 2000); (EPA, 2007b); (EPA, 2007c).

Oil Shale and Tar Sands

Introduction

Oil shale and tar sands represent two relatively untapped reserves of fossil fuels; they form a subset of oil-based energy generation that is not widely used. While they are not currently viable because of economic factors, we include them in this analysis because of their potential impact on water resources in the Western U.S.

In both oil shale and tar sands, organic material is trapped in sedimentary deposits; mining and extensive processing of the rocks produces petroleum. Oil shale deposits are found in the United States, Russia, Australia, and Brazil, and are actively mined in Estonia. The richest, most economically attractive deposits in the United States are found in Western Colorado, a notably water-limited region. Active mining of tar sands currently occurs in Alberta, Canada.

Generation Technology

Oil shale is extracted and processed in one of four major ways: Direct-heated Aboveground Retorting (AGR), Indirect-heated AGR, Modified In-Situ (MIS), and combinations of MIS and Indirect-heated AGR. In AGR, traditional surface mining techniques are used to remove the oil-rich rock; the rock is then crushed, heated, and enriched with hydrogen, producing crude petroleum. For In-Situ Retorting, the deposits are slowly heated by steam injection, electrical currents, or other methods. The petroleum is then extracted through a conventional well and further refined. This process may have negative implications for ground water supplies; to combat the migration of pollutants into ground water, some operations plan to create a "freeze wall" around the heated region (Bureau of Land Management, 2006b).

The process for extracting tar sands is similar: once mined from surface pits, the tar sands are agitated in liquid "extraction cells" filled with hot water. This releases the bitumen (asphalt), which floats to the surface. The bitumen is further refined and upgraded into synthetic oil (Bureau of Land Management, 2006a). Following extraction, energy generation from both oil shale and tar sands follows the same path as traditional forms of oil.

Water Requirements

This section focuses on the water required for the extraction of petroleum from oil shale and tar sand deposits, and ignores the water requirements for upgrading the petroleum and generating electricity (these steps are described in other sections). Using current technologies, extracting petroleum from oil shale requires water in numerous steps of the process, including the following:

- extraction and retorting;
- dust control during extraction, crushing, and transportation;
- cooling and reclaiming spent shale;
- site revegetation (the surface impact of oil shale mines can be extensive); and
- plant utilities associated with power production and environmental control (Chan et al., 2006).

The water required varies significantly, depending on the type of technology employed in extraction.

Assumptions and Limitations

As noted above, generating energy from oil shale and tar sands deposits is currently limited, primarily due to the high cost of extraction and processing. The oil crisis in the late 1970s served as an impetus for technology research and development; similarly, the recent high cost of fuel has stimulated renewed interest. Little research, however, was conducted during the interim. Most research on the water requirements for oil shale production, therefore, dates from the late 1970s. Several industry groups claim that new technological advances reduce the water requirements; as of November 2006, these advances have not been published. Due to the limited available information, the water requirements have not been broken into specific components.

The California Perspective

Significant deposits of oil shale are found in the Green River Formation in western Colorado, Wyoming, and eastern Utah. While the mining and processing of these deposits will not directly impact California's water resources, it could have indirect effects. The deposits lie within the Colorado River basin, which provides an important source of water for Southern California. Using this Colorado River water for mining oil shale will likely compete directly with agricultural and municipal demands in Southern California. Like coal plants in the interior southwestern states that provide a significant portion of California's power mix, the energy derived from oil shale could also be feasibly delivered to California. Tar sands deposits are not found within the western U.S. and are unlikely to have any impact on California's water or energy resources.

Opportunities for Non-Potable Water Use

Non-potable water could be used in several steps of the mining and processing of oil shale and tar sands deposits, including extraction, dust control, shale reclamation, and site re-vegetation. Regarding opportunities for using non-potable water in the oil refining steps, refer to the sections describing traditional oil processing.

Renewable Energy

Renewable energy is derived from resources that are regenerative or for all practical purposes cannot be depleted[10]. The State of California has defined a list of primary energy sources it considers renewable under its Renewable Portfolio Standard (RPS). Our analysis referred to this list for our delineation between renewables and non-renewables. This section includes information on electrical generation from: bioenergy, geothermal, solar, and wind.

Bioenergy

Introduction

Bioenergy encompasses any type of energy generated from recently-living biological matter or their byproducts. A renewable source of energy, it offers greater reliability than solar or wind power: energy generation from biomass can occur at any time of day and under any weather conditions. Like all renewable sources of energy, its ability to provide energy independence makes it increasingly attractive. In addition, energy generated from the combustion of biomass produces less net air pollution such as sulfur compounds, nitrogen oxides, and carbon dioxide than comparable energy generation from coal-powered plants (USDOE - EIA, 2007a). Currently, most bioenergy in the U.S. is generated from waste products, such as agricultural, mill, or

[10] As defined by Energy Efficiency and Renewable Energy, U.S. Department of Energy.

forest residues. The collection and processing of these wastes offers the additional benefit of keeping them out of landfills. In California, for example, 62 percent of wastes currently used to generate biofuels would otherwise be sent to a landfill (Serchuk, 2000).

Both the United States and Europe anticipate increasing their biomass energy generation capacity in the near future: the EU boasts a long-term goal of generating 20 percent of its energy from biomass (International Energy Agency, 2002b). Likewise, the EIA estimates that in order for the U.S. to meet its goal of a 20 percent RPS in 2020, bioenergy will be relied on for 10 percent of overall electricity generation. In addition, the EIA (2001) predicts that 85 percent of this energy, or 526 million MWh, will be generated in biomass dedicated power plants; two-thirds of the energy feedstocks will come from woody biomass, with the remainder composed of dedicated energy crops (Energy Information Administration, 2003). These projected increases will have significant impacts on land use: growing dedicated energy crops will shift 6 – 10 million hectares of currently unirrigated land into productive use (Tuskan & Walsh, 2001).

Two major sectors use biomass to generate energy, electric utilities and the transportation sector (in the form of ethanol or biodiesel). This analysis focuses on the electricity sector, though several of the processes described are closely related to those used in the transportation sector.

Generation Technology

Biomass can be used to generate electricity in several different ways. The two major categories of feedstocks, or primary materials used to generate energy, are waste products and dedicated crops. Wastes include agricultural residues such as almond hulls or cornstalks, wood products such as forest thinnings or chipped wood, landfilled materials, animal wastes, and sewage at wastewater treatment plants. The second major category of feedstock includes crops grown with the specific purpose of generating bioenergy; these dedicated energy crops include willow, switchgrass, sugarcane, corn, and soybeans, among others. The technology used to generate electricity from this range of feedstocks varies significantly, as do the water requirements.

With the exception of waste at wastewater treatment plants, all of the feedstocks listed above can be burned to generate heat, which is used to produce electricity directly or indirectly (by creating steam). These feedstocks may be burned exclusively, or used as additives in coal-firing plants.

The second major way of generating electricity from biomass involves converting the biomass to gaseous or liquid fuel and burning that fuel. As waste degrades, it naturally produces methane, in the following chemical reaction (Simons et al., 2002):

$$\text{Biodegradable Organic Matter} \xrightarrow[\text{Bacteria}]{\text{Without } O_2} CH_4 + CO_2 + H_2S + H_2O + \text{Others}$$

Power plants may enhance the conversion process by using some of the heat from combustion to heat the organic matter, which increases the rate of waste decomposition. Cultivating an anaerobic, microbe-rich environment may also increase rates of decomposition and produce methane at a faster rate. Landfills and wastewater treatment plants can capture the methane produced onsite and generate electricity by combusting this gas. Combustion can drive turbines directly (as in fossil fuel-based gas turbines) or heat water, producing steam and electricity. In California, landfill gas is used to generate electricity in gas turbines, boilers, steam turbines, combined cycles, and reciprocating engines (Simons et al., 2002). Combined cycle facilities utilize both gas turbines and steam turbines, and have the highest energy capture efficiency.

The third major way of capturing energy from biomass entails converting the biomass to liquid fuels, then combusting these fuels in a reciprocating engine. Usually, however, this method is used to create fuels for transportation, rather than electric power plants.

Water Requirements

Bioenergy production requires water in two key areas: growing, or producing the primary feedstock, and electricity generation. The following sections describe these water requirements in greater detail.

Water requirements for primary feedstocks vary substantially. Dedicated energy crops have the highest consumption of water (per MWh), due to irrigation needs. Within the agricultural sector, water requirements may vary considerably, depending on the growing environment, patterns of precipitation, groundwater supplies, and the crop grown. Crops irrigated in an arid environment, for example, will require significantly more water than crops grown in natural floodplains. Bioenergy can also be generated using agricultural residues or wastes. This analysis assumes that the energy generated from agricultural residues is a secondary product. Therefore, the water used to irrigate the primary crops is not included in this analysis. For example, almonds grown in California's Central Valley require irrigation water; we do not include this irrigation water as a requirement for generating electricity from almond hulls.

Regardless of the primary feedstock, all biomass-based energy generation processes require some water during the combustion phase. Similar to traditional coal power plants, water is required for boilers (to generate steam), for cooling, and in some recirculating systems (to condense steam). Although dedicated biomass-based plants are usually smaller than fossil-fuel based plants, they typically have water requirements (per MWh) comparable to those of fossil fuel-based plants (EPA, 2007a). The amount of water needed varies, depending on the type of cooling system employed; as with other thermoelectric generation facilities, once-through cooling requires significant water withdrawals, most of which is returned to the original water body (though at a higher temperature). Recirculating systems, which can be wet- or dry-cooled, use water for cooling, but capture, condense, and recirculate most of the water. Facilities cooled by recirculating systems withdraw significantly less water than systems using once-through cooling technology, but they *consume* more water, primarily due to evaporative losses in cooling towers or ponds, or due to cooling water blowdown. The process of gasification, which converts biomass to syngas prior to combustion, also requires steam in the gasifier.

Landfills or other biomass-based plants that generate energy from captured methane gas have water requirements similar to those of fossil fuel-based natural gas plants. Cooling systems account for these plants' primary use of water; as with solid biomass-based plants, the water required varies, depending on cooling technologies. The major difference between landfill gas to energy facilities and conventional natural gas facilities lies in the gas-capturing process: gas captured from landfills has approximately 50 percent of the methane content of conventional natural gas. Landfill gas to energy power plants, therefore, must adapt the gas injection technologies. In addition, landfill gas typically has a higher moisture content than conventional natural gas. This moisture must be removed from the gas prior to combustion. The Burbank, California facility collects this water then disposes of it by flaring it with excess gas. The facility does not recycle or reuse this wastewater, due to the amount of energy needed to adequately treat it (Owen, 2007).

Assumptions and Limitations

The most important assumption made in this analysis regards the water included for generating electricity from agricultural residues. As described above, the water for irrigation of agricultural products is excluded if electricity is generated from the residues. In addition, the estimates of water withdrawals for dedicated energy crops equal the estimates for water consumption. The primary resource relied upon for irrigation needs described water requirements in terms of "water use efficiency". This is the amount of water evapotranspired by a plant, relative to the energy stored in its tissues. Inefficient systems of irrigation may lead to *significantly* higher withdrawals.

For waste-based bioenergy, predicting the rate of methane gas production from a landfill can be challenging, as rates vary depending on the type of wastes, age of the landfill, patterns of precipitation, temperature variability, and landfill moisture. In addition, transporting methane gas is expensive; therefore, most electricity generating facilities must be located onsite or close to the landfills.

The California Perspective

With its rich agricultural lands, California and the Western United States potentially have extensive bioenergy resources (Figure 22; Figure 23). Currently, agricultural waste and residues are being processed for energy generation, and a facility to generate energy from animal wastes is planned. Dedicated energy crops would necessarily replace the (potentially) higher value crops currently grown, and are not being grown as of January 2007. Governor Schwarzenegger has recently pushed for increased in-state bioenergy generation; and the Secretary of Agriculture has suggested converting portions of the Imperial Valley to sugarcane plantations, with the express intent of generating bioenergy. According to the CEC, California could triple the energy currently generated from biomass with only a modest increase in the cultivation of dedicated biomass crops (California Energy Commission & Public Interest Energy Research, 2006).

Currently, landfill-gas-to-energy projects are more widespread. Out of a statewide total of 311 active landfills, 51 of them capture methane gas and convert it to energy (Figure 24). These facilities have a generation capacity of approximately 211 MW, but could be expanded by an estimated 45 MW. In addition, 70 facilities currently flare their landfill gas, and could potentially produce an additional 66 MW of electricity. Twenty-six landfills have plans to install energy generation facilities, comprising an additional potential 39 MW of electricity (Simons et al., 2002).

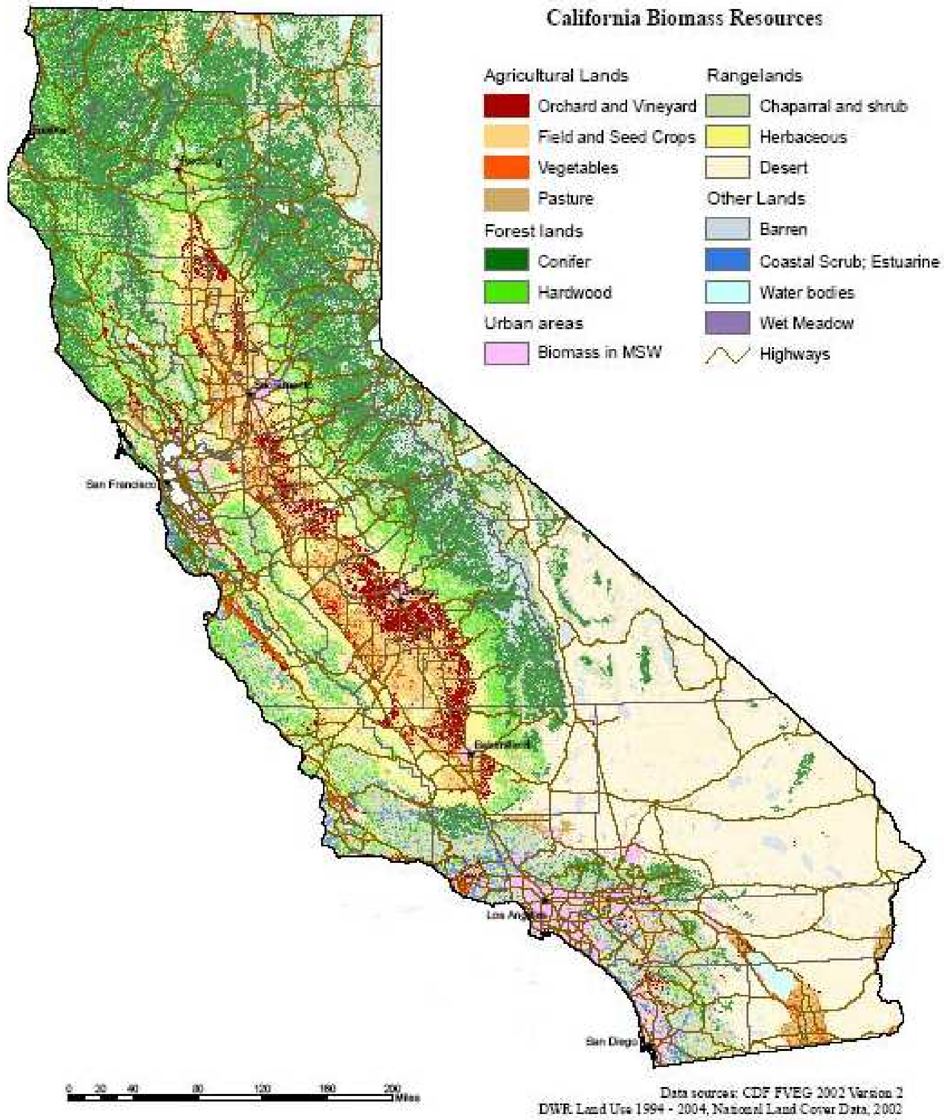


Figure 22. California's biomass resources from currently-used feedstocks (excluding dedicated energy crops) (California Energy Commission & Public Interest Energy Research, 2006).

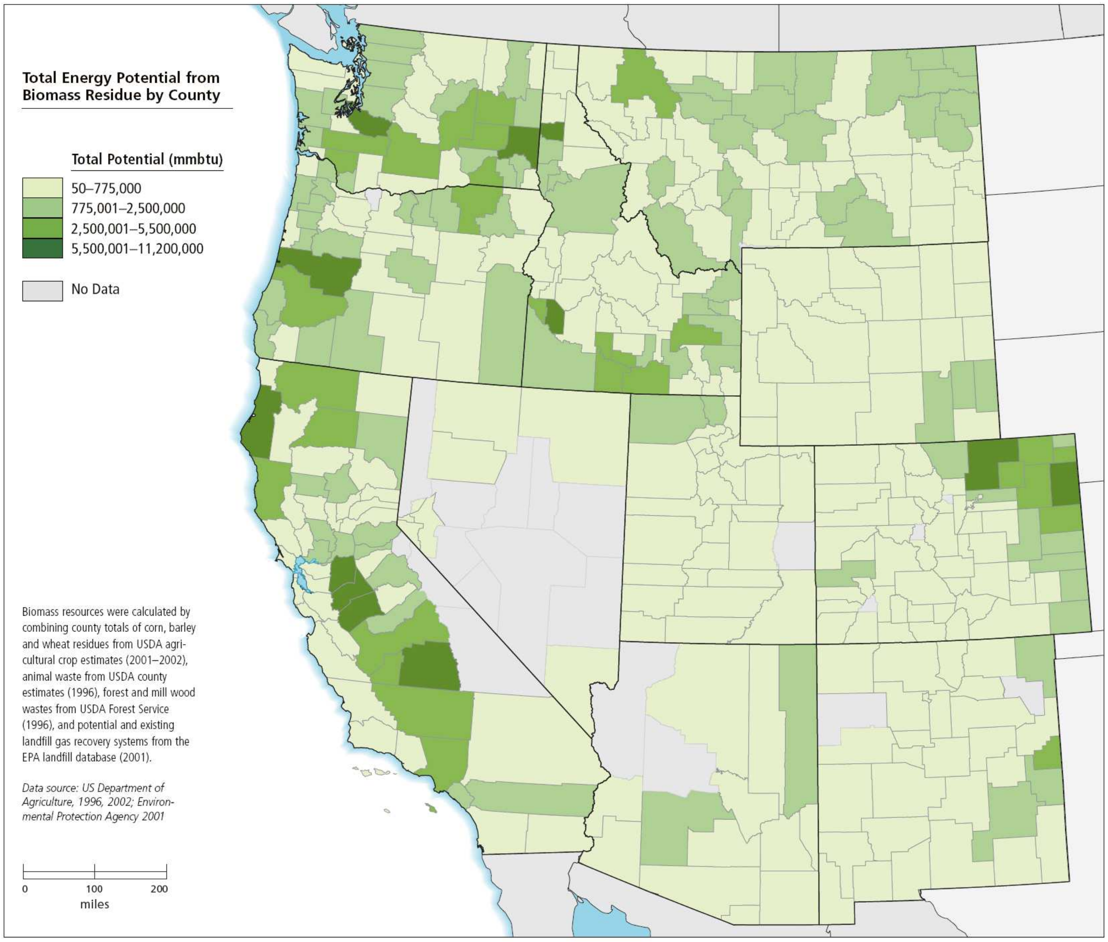


Figure 23. Bioenergy potential in the Western U.S., based on agricultural wastes, residues, landfill gas, and animal wastes. The 17 western states currently have 1,747 MW of installed biomass-based capacity (The Energy Foundation, 2002).

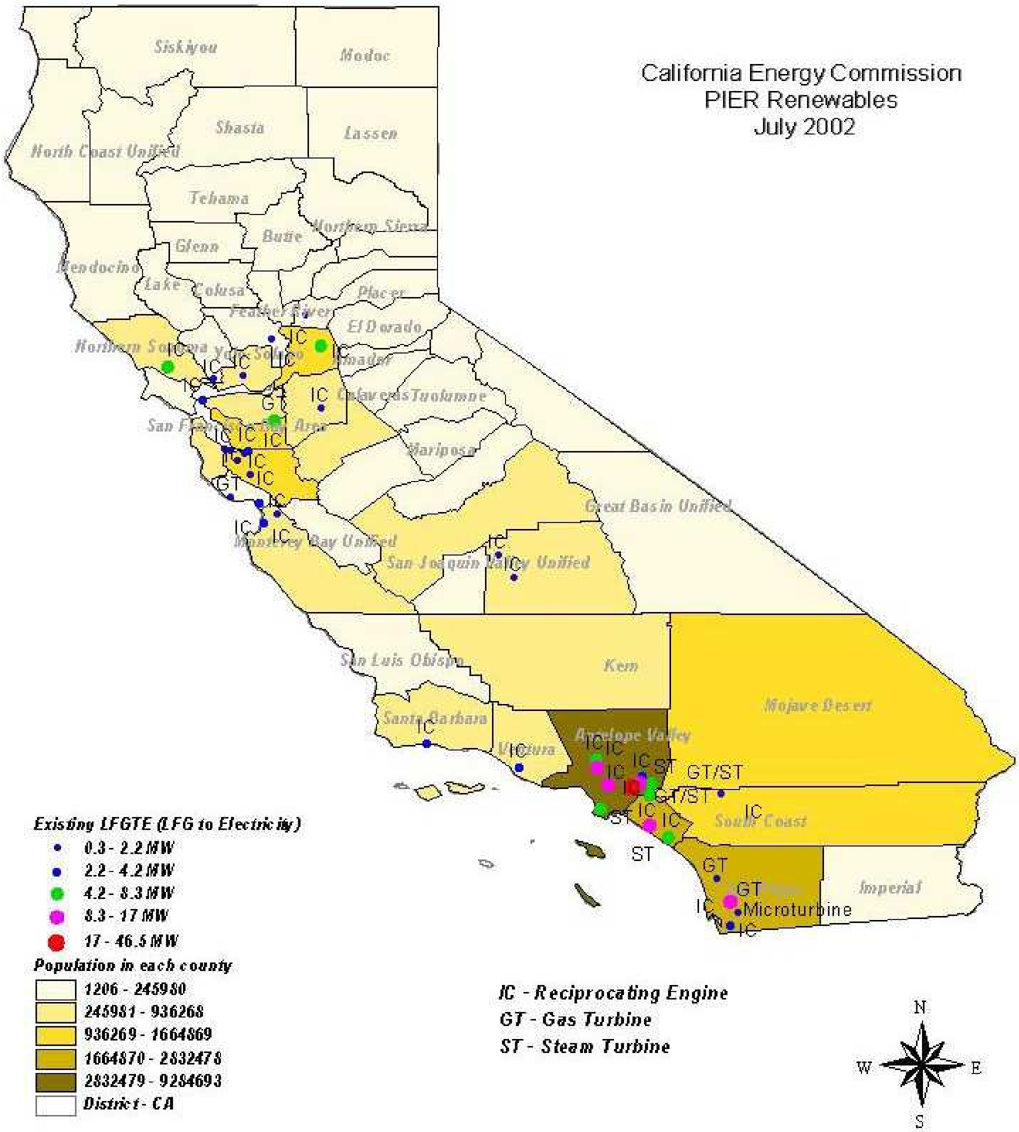


Figure 24. Landfill gas to electricity projects in California in 2002 (Simons et al., 2002).

Opportunities to Use Non-Potable Water

Recycled or reclaimed water could be used in several of the biomass-based energy generation processes. Reclaimed water could feasibly be used to irrigate dedicated energy crops, provided that it does not negatively impact groundwater resources or create sanitation concerns for other crops (i.e. edible crops grown in neighboring plots). Recycled water, however, is usually produced in municipal areas, and may not be easily delivered to prime agricultural areas in the volume required without significant energy inputs for pumping. As with other thermoelectric generation technologies, reclaimed water can be used for the cooling and condensing phases of electricity generation

Environmental Impacts

Relying on biomass for energy has both advantages and disadvantages. As with all renewable sources of energy, it represents a more "carbon-friendly" source of energy. Methane gas has a much higher greenhouse gas potential than CO_2; by capturing and processing gas generated in landfills, these facilities may significantly reduce their impact on climate change. In addition, the growing of dedicated energy crops may aid waning farming communities. Other situations where biomass has had a positive effect include the use of biomass crops to reclaim marginalized land, to power a desalinization plant (providing irrigation water), and in providing surplus energy (Chiaramonti et al., 2000).

Biomass remains controversial for several main reasons (other than its potentially high water requirements). In order to generate significant amounts of electricity, wide tracts of land may be required to grow feedstocks. Parrish and Fyke (2005), for example, estimate that in order to generate 80 EJ (over 22 million MWh) of energy, which is the U.S.'s current consumption of fossil fuel based electricity, 460 million hectares would be required *under the most optimistic conditions*. In comparison, in 2002, total farmland in the U.S. was approximately 380 million hectares, with only 175 million hectares of harvested cropland. Similarly, Spitzley and Keoleian (2004) compare land use for different types of energy generation (Figure 25). The substantial area required for biomass production will likely have negative impacts on native wildlife, water and air quality (from pesticides or fertilizers), and increased rates of soil erosion.

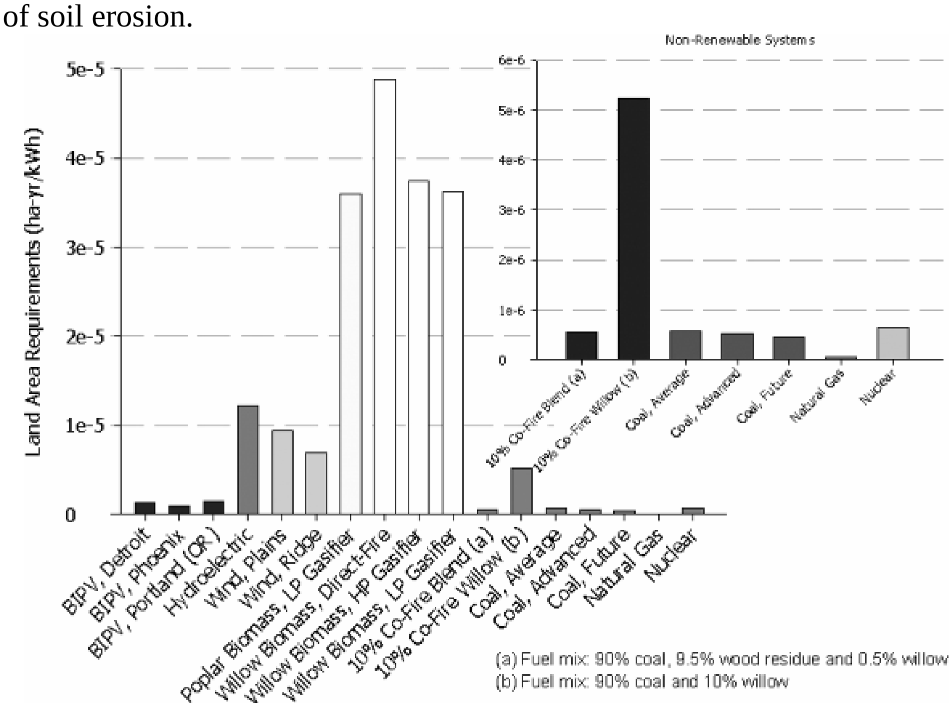


Figure 25. Total life cycle land area requirements for electricity generating technologies. BIPV stands for building integrated photovoltaics; LP and HP indicate low pressure and high pressure, respectively (Spitzley & Keoleian, 2004).

Geothermal

Introduction

Geothermal electricity is produced by drilling wells to pump steam or water ("geothermal fluid") heated by underground magma to drive a turbine. Given that the earth's interior will remain at a high temperature indefinitely, and that water will continue to seep into the ground, geothermal energy is considered a renewable form of energy. Geothermal power can be used not only for electricity production, but also for heating water and buildings (USDOE - EERE, 2006). Our report, however, will focus on electricity generation from geothermal heat.

Precautions must be taken to avoid over-extracting geothermal steam or fluid. The Geysers, a steam-dominated geothermal field in California's Lake and Sonoma Counties, reached a peak production of over 1600 MW in 1987 (Geothermal Research Council, 2003); (Sass & Priest, 2002). Loss of pressure in the field, as the steam field was gradually depleted due to mismanagement, led to declines in electricity production (U.S. Water News, 2001). Another potential concern with geothermal technology is the low efficiency in converting thermal to electric energy. While fossil and nuclear fuels have system efficiencies of 30 – 40 percent, geothermal efficiency is only 15 percent for The Geysers and 10 percent for water-dominated power plants such as the Heber Geothermal Field in the Imperial Valley (Gleick, 1994); (Geothermal Energy Association).

Generation Technology

Three types of geothermal power conversion technologies exist. The first is the dry steam power plant (Figure 26), in which underground steam is directly extracted to turn a turbine to generate electricity, and the condensed steam that does not escape from the plant is "reinjected" back into the geothermal field where it vaporizes again for reuse (USDOE - EERE, 2006). The Geysers is the only dry steam geothermal plant in California. It generates about 1,000 MW annually (Sass & Priest, 2002). In 2005, about 61 billion kilograms of steam were produced, and about 54.2 million m^3 of water were reinjected at The Geysers. This injected water constitutes about 89 percent of current electricity production of The Geysers (DOGGR, 2005).

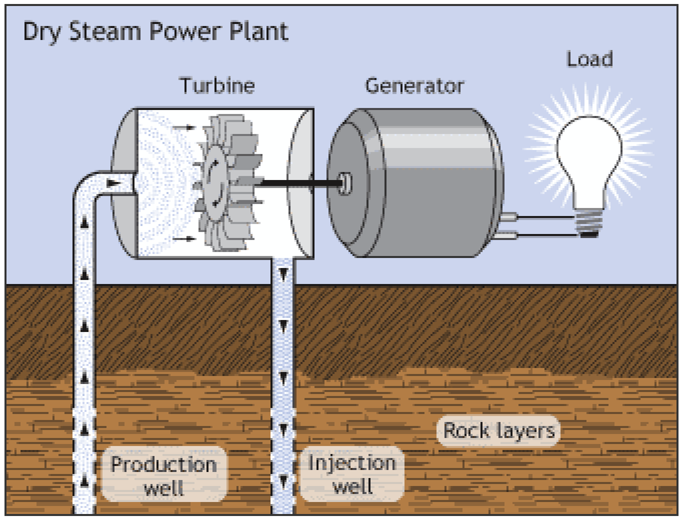


Figure 26. Schematic of a dry steam power plant (USDOE - EERE, 2006).

The second technology is the flash steam power plant (Figure 27). Steam-dominated fields are relatively rare in the world, as most geothermal fields are water-dominated. Water above 182°C, however, can be used by flash steam power plants to produce electricity. In these plants, geothermal fluid is pumped and kept at high pressure to be released into a tank under lower pressure, causing the fluid to flash into steam, which turns the turbine producing electricity. Any remaining liquid can then be flashed a second time to produce extra energy. As with dry steam power plants, some of the condensed steam is reinjected into the geothermal field for reuse (USDOE - EERE, 2006). At least fifty percent of the withdrawn fluid is reinjected (Kagel et al., 2005).

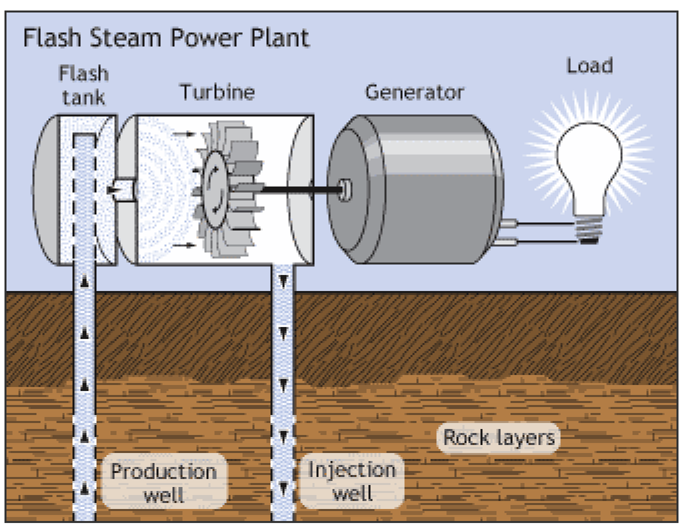


Figure 27. Schematic of a flash steam power plant (USDOE - EERE, 2006).

Geothermal fluid under 175°C cannot be flashed into a tank, as its pressure is too low as it is extracted. The fluid, however, may still be warm enough to heat up another liquid ("binary fluid") with a boiling point low enough to create steam. This is known as a binary-cycle power plant (Figure 28), which is the third of the conversion technologies. Binary-cycle plants have the fewest adverse effects on the environment, as they are closed fluid systems. All of the extracted fluid is reinjected, as shown in Figure 28 (USDOE - EERE, 2006).

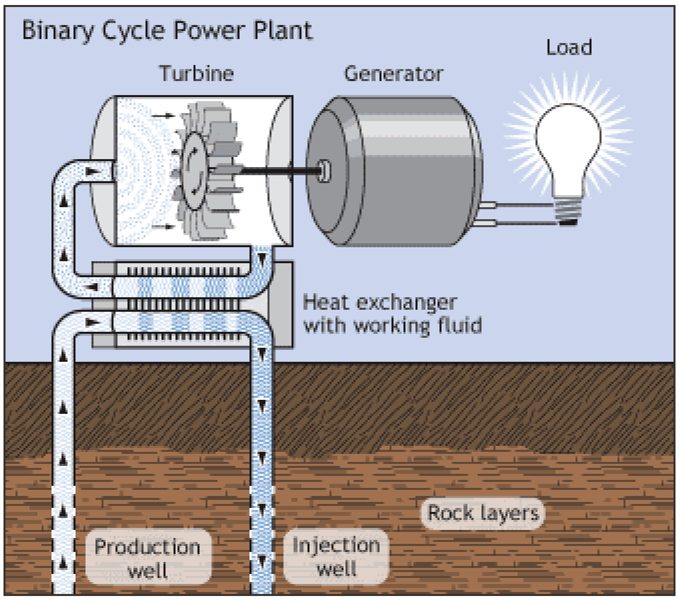


Figure 28. Schematic of a binary cycle power plant (USDOE - EERE, 2006).

Cooling Technology

Geothermal plants use wet recirculating and dry cooling systems much like those of fossil fuel plants. Dry and flash steam plants usually use wet recirculating cooling, whereas binary cycle plants usually use dry cooling (Kagel et al., 2005).

Water Requirements

The fluid used by geothermal plants is separate from freshwater aquifers used in a municipal water supply, and the used fluid is reinjected back into the geothermal site, so there is no effect on municipal water supply. Geothermal plants, however, require some freshwater for their cooling systems. Dry cooling systems for geothermal plants require no water at all, and a wet cooling system for a 48 MW flash steam plant uses only 0.019 m^3/MWh of freshwater. The low demand is partially due to the fact that some condensed geothermal steam can be used for cooling, although surface water is also used (Kagel et al., 2005); (Schochet, 2007).

Assumptions and Limitations

The main limitation of geothermal power is although the magnitude of generation can be greatly increased, suitable locations for geothermal plants are strictly confined to the sites where the underground geothermal fluid is located. See The California Perspective for the location of these sites in California.

For our analysis, we assume that geothermal facilities operate at 90 percent capacity (Kagel et al., 2005). We also assume that geothermal fluid will not be over-extracted from today until 2030, for the scenarios we worked with in our analysis. In other words, the remaining lifetime of all geothermal resources in California is assumed to be at least 23 years, with generating capacity of each geothermal resource remaining constant over those 23 years.

The California Perspective

The known geothermal fields in California are shown by the map in Figure 29. The most likely total generating capacity, along with the existing installed generating capacity, and the current amount generated for each geothermal field in California is shown in Table 8.

Although over 2,500 MW of geothermal power was generated around 1990, this figure has dipped somewhat; in 2005, 1,870 MW of electricity was produced by geothermal plants in California (California Energy Commission, 2005b). As geothermal technology continues to improve with the development of more advanced wells and plants (Sass & Priest, 2002), the future of geothermal power in California is optimistic; the total amount of production capacity in California is estimated to be 4,732 MW, meaning that an additional 2,862 MW can be generated by the known geothermal fields in the state (California Energy Commission, 2005b); (Table 8).

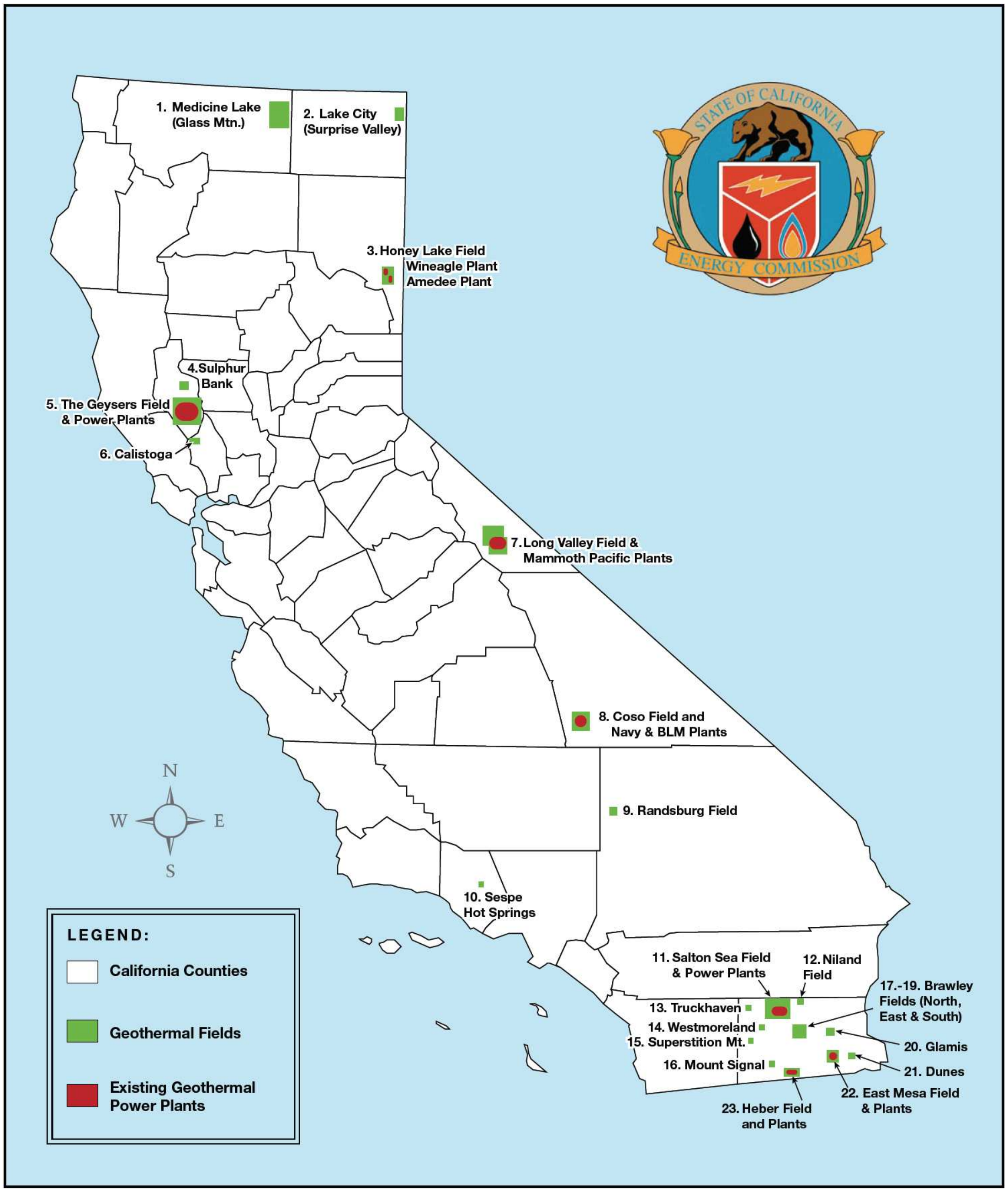


Figure 29. Geothermal fields of California (California Geothermal Energy Collaborative/GeothermEx Inc., 2006).

Table 8. The most likely (MLK) total generating capacity, along with the existing installed generating capacity (existing gross), and the difference between the two (MLK – existing) for each geothermal field in California (California Energy Commission, 2005b).

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK-Existing MW
Brawley (North)	Imperial	135	0	135
Brawley (East)	Imperial	129	0	129
Brawley (South)	Imperial	62	0	62
Dunes	Imperial	11	0	11
East Mesa	Imperial	148	73.2	74.8
Glamis	Imperial	6.4	0	6.4
Heber	Imperial	142	100	42
Mount Signal	Imperial	19	0	19
Niland	Imperial	76	0	76
Salton Sea (including Westmoreland)	Imperial	1750	350	1400
Superstition Mountain	Imperial	9.5	0	9.5
	Imperial Total:	2487.9	523.2	1964.7
Coso Hot Springs	Inyo	355	300	55
Sulfur Bank Field, Clear Lake Area	Lake	43	0	43
Geysers [Lake & Sonoma Counties]	Sonoma	1400	1000	400
Calistoga	Napa	25	0	25
	The Geysers Total:	1468	1000	468
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City/ Surprise Valley	Modoc	37	0	37
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	111	40	71
Randsburg	San Bernardino/ Kern	48	0	48
Medicine Lake (Fourmile Hill)	Siskiyou	36	0	36
Medicine Lake (Telephone Flat)	Siskiyou	175	0	175
Sespe Hot Springs	Ventura	5.3	0	5.3
Total:		**4732**	**1870**	**2862**

Opportunities for Non-Potable Water Use

To address the problem of over-extraction of The Geysers, two wastewater pipelines were built for the purpose of reinjecting wastewater into the geothermal field, to maintain the steam supply. The first of these pipelines is a 29-mile pipeline built in 1997, carrying 30,000 m^3/day from Clear Lake and treated effluent from sewage treatment plants in Lake County. The second pipeline is the Santa Rosa Geysers Recharge Project, a 40-mile pipeline transporting half the wastewater generated annually by the cities of Santa Rosa, Rohnert Park, Cotati, and Sebastapol. This newer system will carry 11 million gallons per day and produce enough steam to generate an extra 85 MW of electricity. The two pipelines combined will allow full replacement of the steam of The Geysers, allowing for long-term sustainability of the geothermal field (Geothermal Research Council, 2003); (Sass & Priest, 2002).

Environmental Impacts

Air and water impacts

Geothermal fluid itself has its own environmental considerations, as it contains dissolved carbonate, bicarbonate, and carbon dioxide, as well as hydrogen sulfide, ammonia, and methane (Reed & Renner, 1995). Geothermal fluid, as it is vaporized, releases these materials into the atmosphere, causing some impact to the air, but the overall air emissions from geothermal steam are miniscule compared to those of fossil fuels, as shown in Table 9:

Table 9. Comparison of impacts to the air between geothermal and fossil fuel plants, in kilograms per MWh produced in 1991 (Reed & Renner, 1995).

	Carbon dioxide	Sulfur oxides	Nitrogen oxides
Coal	990	9.23	3.66
Petroleum	839	4.95	1.75
Natural gas	540	N/A	1.93
Geothermal	0.48	0.03	0

As geothermal plants do not combust any separate fuel, carbon emissions are low. Furthermore, since they do not require the high pressures required for combustion, nitrogen oxide emissions are low. Any ammonia is oxidized to nitrate and water in flash steam power plants. Hydrogen sulfide, detectable by humans in concentrations as low as 1 ppm, can be reduced as low as 1 ppb through the Stretford process used by The Geysers, which converts hydrogen sulfide into SO_2, which is then transformed into SO_3^{2-} and SO_4^{2-}. Nevertheless, sulfur emissions are nowhere near that of fossil fuels (Table 9); (Reed & Renner, 1995).

Water pollution is also a concern with geothermal plants, but this concern is mitigated, as hazardous elements such as mercury, boron, arsenic, and chlorine are injected back into the geothermal source. Geothermal fluid has from 0.1 to over 25 percent by weight of dissolved solutes. This figure varies greatly depending on the rock type, temperature, and pressure of the geothermal source. The danger is that dissolved silica can precipitate and damage the components of the geothermal plant. To prevent this, precipitation is delayed until the fluid reaches a crystallizer or settling pond. A similar problem occurs with the dissolved brine in geothermal fluids near the Salton Sea, and crystallizers are used in plants pumping those fluids as well (Reed & Renner, 1995).

In the U.S., only potable lower-temperature geothermal waters are allowed to flow into surface waters; all other cooled water must be reinjected back into the geothermal source. Structural enhancements, maintenance, and diagnostic tests are used to ensure that no reinjected water leaks into freshwater aquifers (Reed & Renner, 1995).

Land use impacts

Geothermal plants take up less land than nuclear and coal plants. About 1 – 8 acres/MW is required for a geothermal plant, compared to 5 – 10 for nuclear and 19 for coal (Shibaki, 2003). Geothermal plants are often located next to lands used for agriculture and grazing (Reed & Renner, 1995). For example, the Hell's Gate National Park in Kenya is located among three geothermal plants. The area is used for livestock grazing, growing of food and flowers, and wildlife conservation (Shibaki, 2003).

The primary danger of geothermal plants to land is ground subsidence, as geothermal fluid is taken away faster than it is recharged during construction and operation. The largest such incident was at Wairakei, New Zealand, in which the ground subsided up to 13 meters. The only preventative action available is to try to maintain pressure in the reservoir by reinjecting geothermal fluid during construction (Kagel et al., 2005); (Shibaki, 2003).

Earthquakes can be caused by geothermal operations. Most of these earthquakes are between 2 and 3 in the Richter scale, too weak to be felt. The Geysers experienced a magnitude 5.7 quake in 1969, but the USGS does not consider seismic activity in The Geysers area to be significantly different from that of California in general (Kagel et al., 2005).

Solar Power

Photovoltaic Solar Technologies

Introduction

Energy generation from photovoltaic solar technologies (PV) offers a zero-carbon solution to our world's mounting energy demands. Photovoltaic solar technologies use chemical means to transform the sun's energy into usable electricity. Two main types of PV systems are currently in use. The first, flat plate collectors, are the most familiar and are commonly used in residences. The second, concentrating photovoltaic systems (CPV) (Figure 30), are a newer technology and less common. CPV systems, with a typical capacity of 10 to 15 kW, are modular in nature (Stoddard et al., 2006).

In 2005, the amount of grid-connected PV capacity increased globally by 55 percent. With a current capacity of 3.1 GW, it is the world's fastest growing power source (Sawin et al., 2006). Widespread implementation of photovoltaic technology faces some obstacles: its energy capture rates are much lower than available solar energy due to inefficiencies in the technology (Union of Concerned Scientists, 2006). Current PV cell efficiency varies, depending on the technology: Thin layer cells made of amorphous silicon convert approximately 8 percent of available solar energy, while high-quality single crystal cells can convert up to 18 percent of available energy (Solar Electric Power Association, 2007). On average, single crystal silicon cells have a 14 percent cell efficiency, yielding a transformation efficiency (sunlight to DC energy) of 11 to 12 percent (Solar Electric Power Association, 2007). In addition to energy conversion inefficiencies, the infrastructure necessary to support PV energy generation is currently insufficient (Union of Concerned Scientists, 2006). Also, distributed solar power currently has a higher cost than conventional grid power (Solar Electric Power Association, 2007).

Figure 30. Solar Systems 20 kW CPV dish (NREL, 2007c).

This technology has great potential to help meet current and future energy demand. Nationally, photovoltaic systems installed on appropriate rooftops throughout the U.S. could meet over 57 percent of current national energy demand (International Energy Agency, 2002a). Furthermore, worldwide, researchers are investigating new solar technologies and high capture efficiency PV cells. These research institutions include the National Renewable Energy Laboratory (NREL), the International Energy Agency (IEA), and many more.

Generation technology

Solar cells, or modules, use silicon as their base. Solar cells are composed of two different layers of silicon; the n-layer which carries a negative charge, and the p-layer, which carries a positive charge. Silicon grips its outer electrons weakly; when light hits the n-layer, some electrons are knocked loose. As they flow to the p-layer, they pass through an electric circuit, generating electricity. While some energy is required to construct solar cells, the electricity generation process produces no emissions of greenhouse gases or pollutants.

CPV systems (Figure 30) use a dish or array of mirrors (sun tracking heliostats) to concentrate solar rays on a smaller, central set of PV panels. These panels are composed of more efficient (and more expensive) cells than those used in flat panel systems. CPV systems have the added advantage over flat panel PV systems in that they can operate away from a grid (though battery storage is useful in this case) and can be used where preexisting mounting surfaces, such as rooftops, are not available.

Water Requirements

Within the boundaries of this analysis, electricity generation from solar photovoltaics requires very little water. The only water required is for occasional washing of the PV cells; this ensures maximum solar energy capture. Up to 10 percent of annual energy capture is lost in dirty modules, especially in dry, dust-prone climates (Solar Electric Power Association, 2007). In areas with regular rainfall or in residential applications, however, washing of cells is less important and less common. PV electricity generation consumes only $0.114 m^3/MWh$ (American Wind Energy Association, 2006b) as compared coal based thermoelectric generation which our research shows requires water withdrawals between 2.3 and 6.5 m^3/MWh.

Assumptions and Limitations

Like some other solar technologies, PV systems rely on direct normal insolation (DNI) and are limited to generating power when direct sunlight is available (insolation refers to solar radiation). In addition, water is used in portions of the silica and cell production processes; these water demands are outside of the scope of this analysis.

California Perspective

The potential for new PV generation capacity in California is approximately 17 million MW, with the greatest potential in the southeastern regions of the state (Simons & McCabe, 2005); (Figure 31). The technical potential for flat plate solar collectors differs from the statewide gross potential, which is determined solely by the amount of DNI available. Technical potential assumes a 10 percent solar capture and conversion efficiency, a somewhat conservative estimate, and that PV systems cannot be constructed over forested areas, open water, protected wilderness areas, or land with a slope greater than 5 percent.

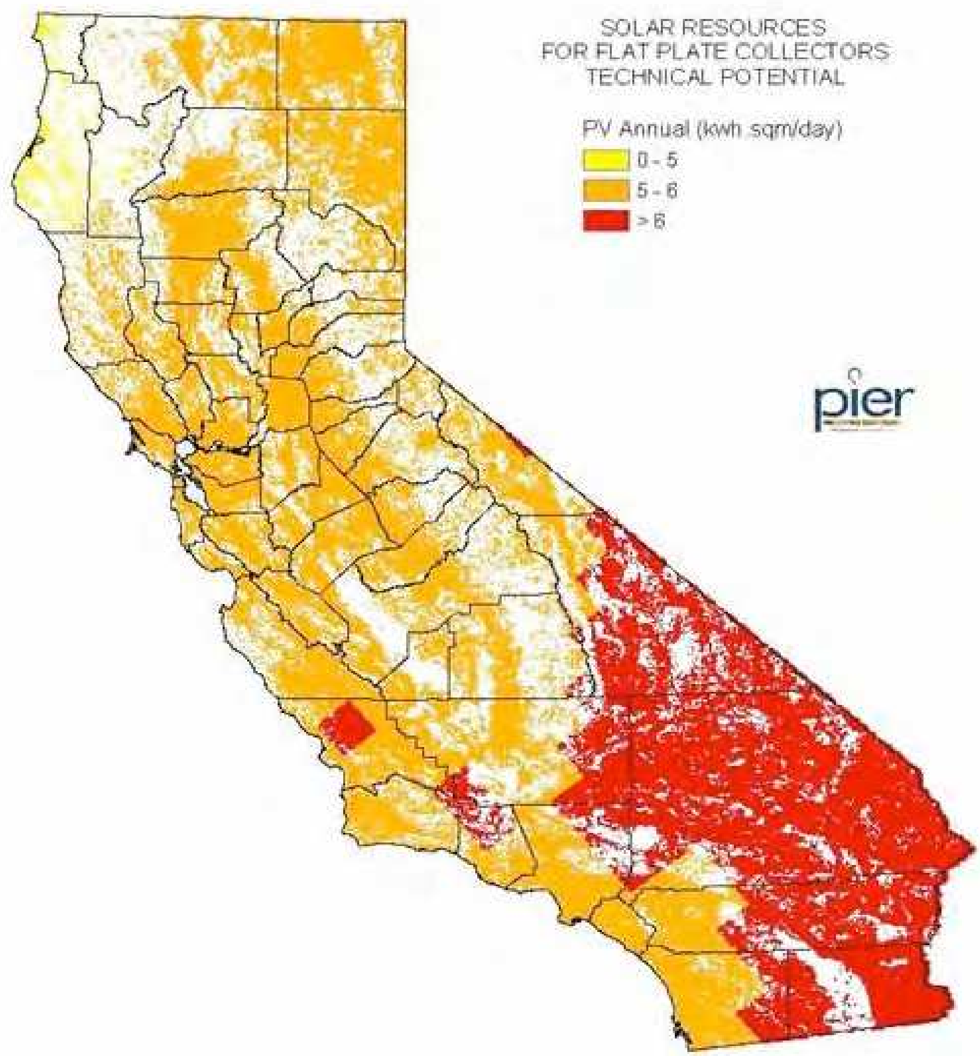


Figure 31. Technical PV potential for California (Simons & McCabe, 2005).

At 38,000 MW, the technical solar PV potential of existing rooftops is roughly on par with the technical potential estimated from commercial buildings, 37,000 MW. The CEC estimated that if all new homes constructed in 2005 included 2.5 kW solar PV systems, 430 MW of new capacity would have been installed (Simons & McCabe, 2005).

In 2004, Governor Schwarzenegger launched the Million Solar Roofs Plan (also known as the California Solar Initiative, or SB 1). The initiative provides $3.2 billion in customer rebates with the overall goal of installing 3,000 MW of new PV generation capacity on one million new and existing California homes, businesses, agricultural properties, and public buildings by 2017 (Sawin et al., 2006). SB 1 applies to both municipal-owned utilities and investor-owned utilities (IOUs), and increases the number of consumers who can receive credit for excess power produced. In addition, the plan requires that solar power systems be offered to buyers of new homes in developments of 50 homes or greater (California Office of the Governor, 2006).

Opportunities to Use Non-Potable Water

Solar photovoltaic panels represent an ideal use of non-potable water. Because generation from PV cells requires minimal amounts of water, and all of the water is consumed, using non-potable water is preferable to potable water resources.

Environmental Impacts

Solar PV has numerous advantages; primary among these is the inexhaustible nature of solar power supply. At noon on a cloudless day, approximately 1,000 watts per square meter reach the earth's surface (Union of Concerned Scientists, 2006). PV cells are made of silicon, one of the most plentiful materials on earth; availability of raw materials, therefore, is not likely to limit PV production (Union of Concerned Scientists, 2006). Additionally, because they are typically placed on existing structures, they require almost no new land area (EPA, 2006a). If an array of PV panels extensive enough to support a major city was constructed in the southwestern U.S., it would need to be very large, creating land use and environmental impact issues. As noted above, however, this is an uncommon use of PV energy generation. Finally, PV systems are one of the easiest types of power generation to install or maintain (Union of Concerned Scientists, 2006), making PV cells a viable option for both residential and large corporate entities.

Solar photovoltaic technology does have some negative aspects. Small amounts of hazardous waste are created in the production of photovoltaic wafers; this waste must be handled properly to protect both humans and the environment (EPA, 2006a). Fortunately, current practices have been very successful in ensuring worker safety and proper waste disposal. Another consideration is the variation in cloud cover, both spatially and seasonally; PV may be a more viable technology in sunnier climates.

Solar Thermal Renewable Energy Technologies

Introduction and Efficiency

Solar thermal technology, often called concentrating solar power (CSP), concentrates and captures the sun's heat. All CSP systems use the direct component of solar radiation, sometimes referred to as direct normal insolation (DNI). Average CSP system efficiency is around 15 percent (Simons & McCabe, 2005).

Generation Technology

There are three main types of CSP technologies: parabolic troughs, parabolic dish engines, and power towers.

Parabolic trough systems focus the sun's heat energy onto oil-filled pipes using long arrays of parabolic, U-shaped, concave mirrors which track the sun throughout the daytime. The pipe carrying oil runs along the center of the trough. The hot oil is then used to boil water in a conventional steam generator, creating electricity.

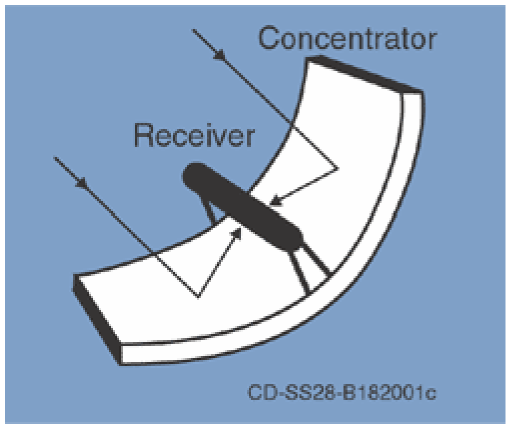


Figure 32. Diagram of a parabolic trough system, which concentrates solar heat onto an oil-filled pipe (OCS - Alternative Energy and Alternate Use Programmatic EIS Information Center).

Parabolic trough systems provide one notable advantage over some other CSP technologies: they can be designed to store thermal energy or with hybrid fossil systems (that use fossil fuels to generate steam and electricity when DNI is not available), in order to dispatch power to the market when it is demanded. This allows greater operating flexibility so that CSP plants can provide power when the utility system needs it rather than only when direct sunlight is available.

Parabolic dish engines use a large mirrored dish, shaped like a large satellite dish, to concentrate solar heat onto a receiver. To maximize solar energy capture, the dish is mounted on a two-axis tracker, allowing it to rotate and point at the sun continuously. This receiver absorbs the heat and transfers it to a fluid inside the engine, most often through a closed hydrogen loop. This transferred heat causes the fluid to expand which in turn pushes a piston or turns a turbine, creating mechanical power and subsequently, electrical energy. Parabolic dish engines are also referred to dish-sterling systems (Stirling Engine Systems is the primary producer of this technology in the U.S.) (Stoddard et al., 2006).

Individual parabolic dish-engine units range from 10 to 25 kW in size. This technology can be operated independent of power grids, making it ideal for remote applications. Currently, no parabolic dish-engine plants are in operation; however, in August of 2005, Southern California Edison announced a 20 year power purchase agreement with Stirling Engine Systems. This agreement will include 500 to 850

MW of generation capacity from Stirling's parabolic dish engine units (Deming, 2007), which will produce between 1,182 and 2,010 GWh annually. In September of 2005, San Diego Gas & Electric agreed to purchase 300 to 900 MW of capacity from Stirling. According to Stoddard et al. (2006), the pricing for these agreements in not publicly available.

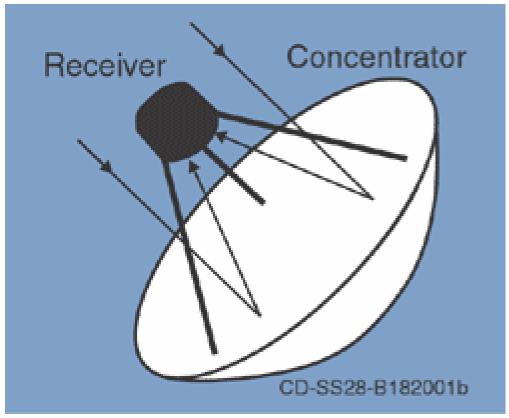


Figure 33. Solar concentrating dish (OCS - Alternative Energy and Alternate Use Programmatic EIS Information Center).

The third CSP technology is the power tower. Commercial power tower plants can produce 50 to 200 MW of electricity, depending on their size (Solar Paces, 2007). Power towers use a large circular field of small mirrors, or heliostats, to concentrate light and heat onto the top of a centrally located tower. A receiver, containing molten salt, is positioned at the top of the tower. The molten salt moves through the receiver and the heat it carries is used to create electricity in a conventional steam generator. Molten salt retains heat well and can be stored for several days before being used for electricity generation (NREL, 2006; Solar Paces, 2007). This allows plants to produce electricity in both sunny and cloudy weather. As with parabolic trough systems, this allows for greater flexibility in power production and enhances ability to meet utility demand, particularly during periods of peak demand.

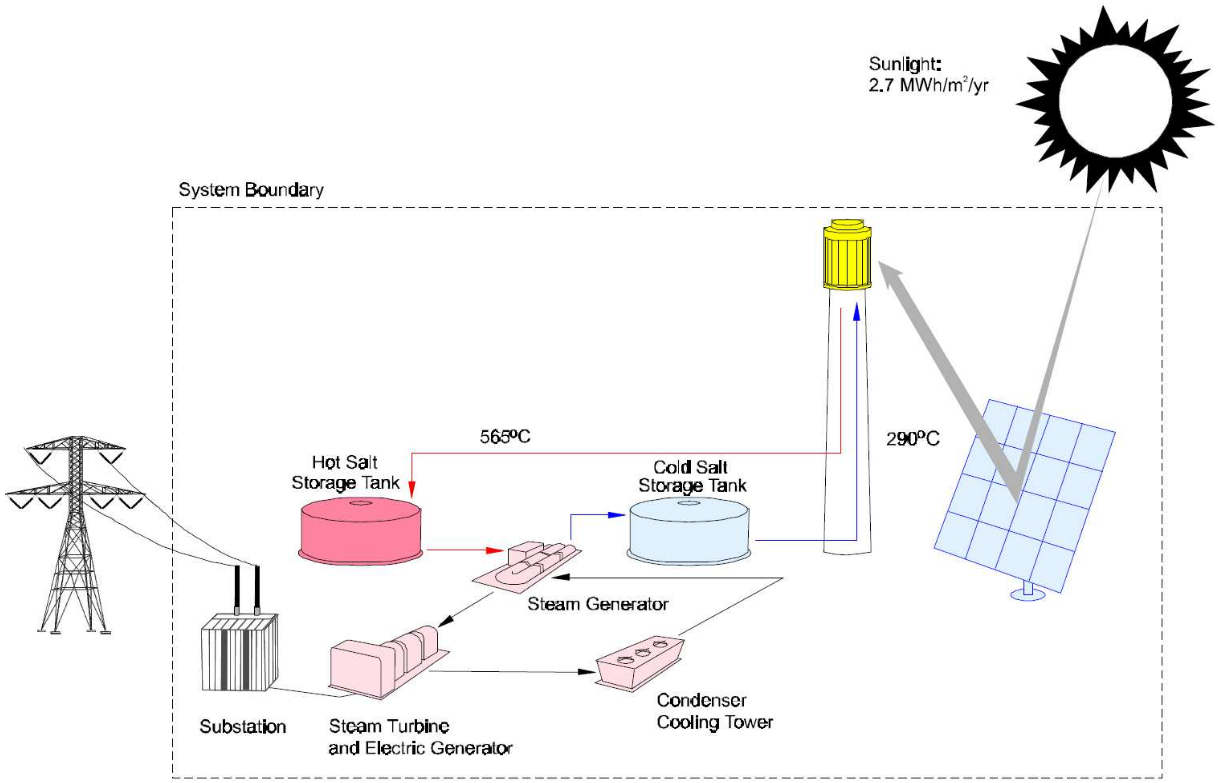


Figure 34. Solar Two, molten salt tower system schematic (NREL, 2006).

Figure 35. 10 MW Solar Two power tower system (NREL, 2006).

Water Requirements

Because other fluids are used for heat transfer in CSP, only a very small amount of water is used in cooling and for mirror cleaning. For large parabolic trough plants that use wet cooling, water consumption is approximately 2.8 m^3/MWh. This water use is roughly equivalent to conventional steam plants (Stoddard et al., 2006). An additional 0.14 m^3/MWh is necessary for cleaning the mirror field.

Parabolic dish engines use even less water than parabolic trough applications. The dish engine, also called the power conversion unit (PCU), is air cooled and does not use any water consumptively for cooling (Stoddard et al., 2006). Significantly less mirror surface is used in parabolic dish engine systems than in parabolic trough systems (which use thousands of heliostats); correspondingly, the amount of water needed to wash the mirrors is less. Because parabolic trough systems require a minute amount of water for cleaning, we assume that the water need to clean the (far smaller) dish engine collection mirrors is negligible.

Power towers, like parabolic trough plants, use approximately 2.8 m^3 per MWh of water for cooling purposes. Here again, a small amount of water is necessary for heliostat washing and is included in this estimate (Stoddard et al., 2006).

Assumptions and Limitations

As all CSP systems use only the direct component of solar radiation (DNI), they are limited in that they are unable to use global radiation, or reflected radiation, which is available on both sunny and cloudy days. To maximize the DNI capture efficiency, concentrating solar systems utilize collecting mirror arrays that track the sun. This reliance on DNI also means that CSP technologies are limited in where they can be sited. These systems must be placed in areas with sufficient amounts of direct sunlight, that is, areas with long days and very little cloudy weather.

A further limitation of parabolic dish engine systems, as opposed to parabolic trough and power towers, is that they have no energy storage capacity. Unlike the other CSP technologies, dish engine systems cannot use their internal heat transfer medium to store heat energy, allowing for continued electricity generation during short cloudy periods or after sunset. As dish engine systems do not use hybrid fossil systems or other forms of thermal energy storage, they cannot provide utilities with a firm energy resource.

The California Perspective

Concentrating solar power technologies are ideal for widespread application throughout Southern California. With the exception of parabolic trough plants, CSP technologies use considerably less water than combustion or nuclear alternatives. The southern portion of the state, which has the highest potential DNI capture (receives the most sunlight) is also the most arid (NREL, 2006). CSP technologies, therefore, are a reasonable choice for these areas. In addition, much of the interior portion of Southern California has historically been sparsely populated. This is rapidly changing as the statewide population grows and people continue to settle in newly-constructed outer suburbs of Los Angeles.

Each of the solar generating technologies could be viable in California. Currently, parabolic trough systems are the most commercially viable CSP technology (Sawin et al., 2006). With conventional steam turbines as their method of generating electricity, however, water requirements for parabolic trough plants are similar to those of thermoelectric plants. Refining and implementing the dry cooling process in parabolic trough facilities may mitigate this issue. Parabolic dish-engine systems would also be a viable choice for much of Southern California. As they require water only for infrequent washing of the heliostats, they have essentially no impact on water resources. In addition, parabolic dish-engines can operate independently of a power grid, requiring less new infrastructure in undeveloped or remote areas. Solar power towers can store heat and deliver electricity during cloudy periods, making them versatile and able to meet baseload needs.

In terms of the electricity generating potential of the state, the average annual daily DNI for high insolation areas of the state (i.e. areas of low cloud cover) ranges from 6.75 kWh/m^2-day to 8.25 kWh/m^2-day (Stoddard et al., 2006). As annual electric energy generation from CSP plants is generally proportional to the annual average DNI level, the areas of highest DNI will be the most productive for electricity generation.

Figure 37 shows areas in California with large amounts of DNI/high solar resources and land slope less than 1 percent (Stoddard et al., 2006). This slope restriction is preferable for both parabolic troughs and power towers. Table 10 shows the land area that meets the requirements for each technology type and the corresponding generation potential. Capacity and generation estimates within Table 10 refer to CSP systems that do not have additional thermal storage. Note that each CSP technology alone has the potential to produce several times the current statewide electricity demand. The total generation capacity as of 2004 for the state was approximately 58,000 MW (Stoddard et al., 2006). According to Simons and McCabe (2005), statewide CSP technical potential is approximately 1,000,000 MW, an estimate on par with the more conservative estimates listed below. It is important to note that most concentrating solar power is available during the daytime, essentially during peak demand.

Concentrating Solar Power Prospects of California

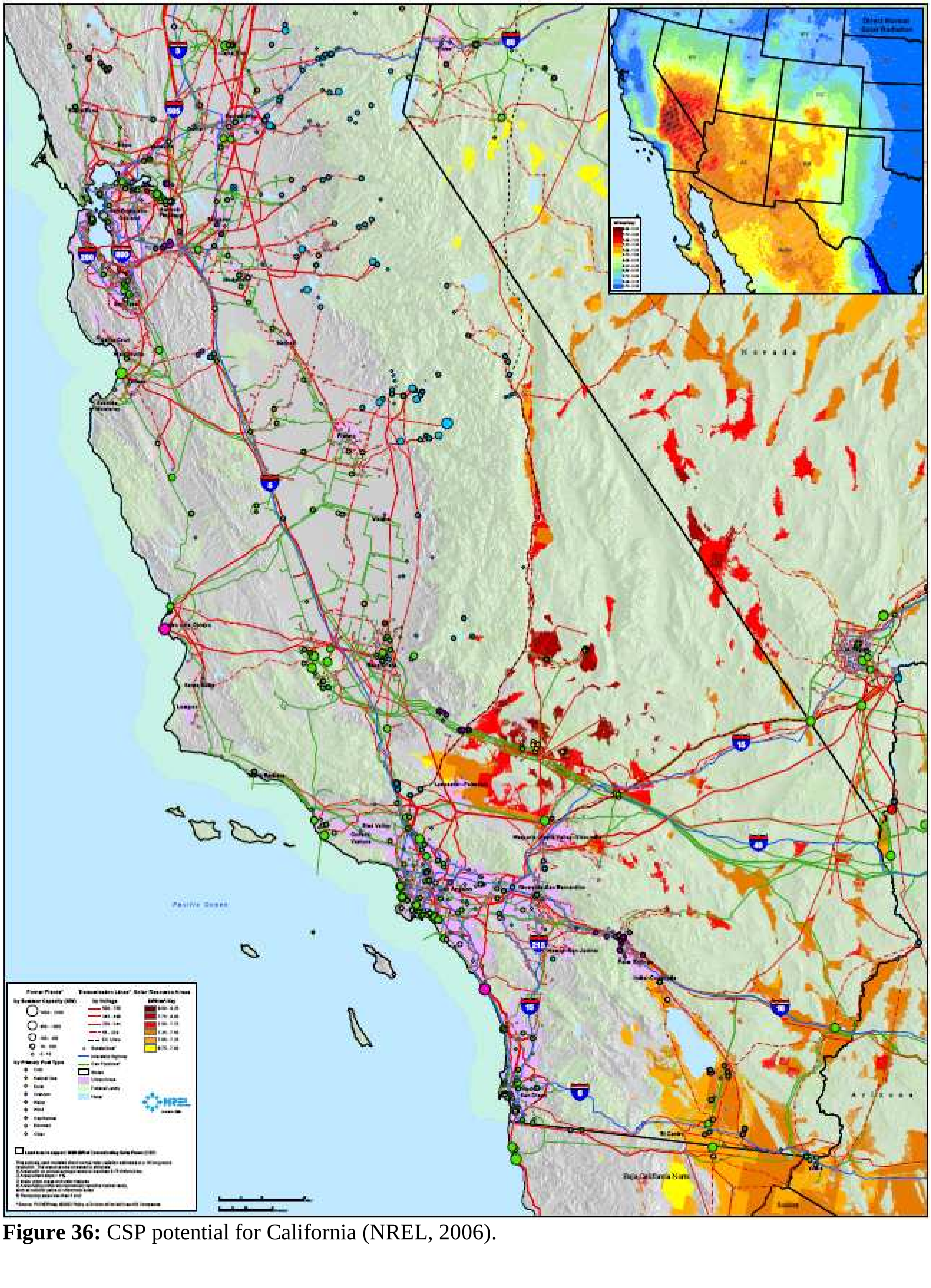


Figure 36: CSP potential for California (NREL, 2006).

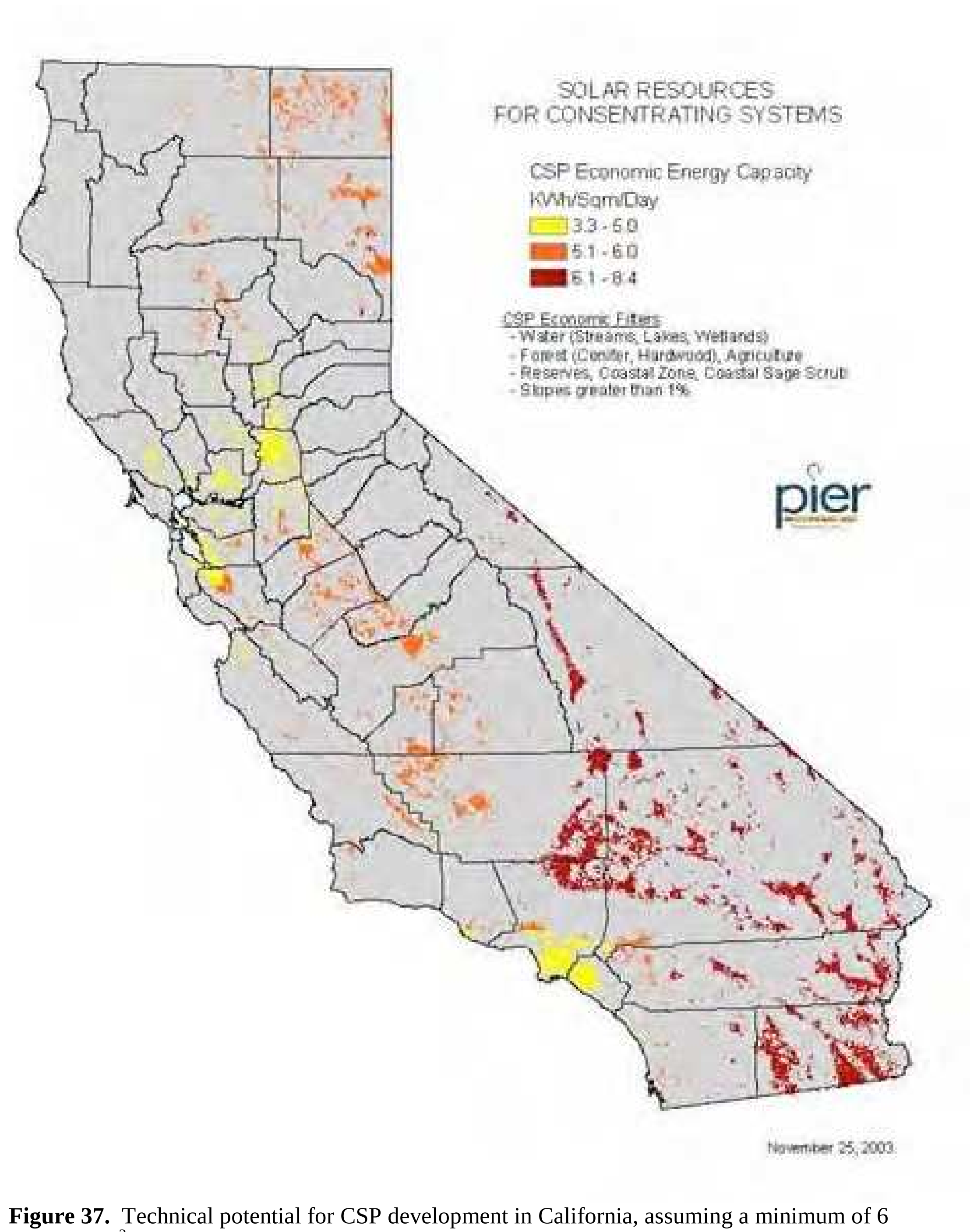


Figure 37. Technical potential for CSP development in California, assuming a minimum of 6 kWh/day/m^2 (Simons & McCabe, 2005).

Table 10. CSP potential development within California (Stoddard et al., 2006).

Concentrating Solar Power Technical Potential			
	Land Area (km^2)	Capacity Potential (MW)	Generation Potential (GWh)
Parabolic Trough (no storage) <1% slope	15,281	661,000	1,614,000
Parabolic Trough (six hours storage) <1% slope	15,281	471,000	1,640,000
Power Tower (six hours storage) <1% slope	15,281	342,000	1,233,000
Parabolic Dish <3% slope	30,044	1,480,000	3,371,000
Parabolic Dish <5% slope	37,296	1,837,000	4,196,000
Concentrating PV <3% slope	30,044	1,235,000	2,859,000
Concentrating PV <5% slope	37,296	1,534,000	3,558,000

Opportunities for Non-Potable Water Use

Reclaimed water can be used for heliostat and mirror washing. If treated to an acceptable level, recycled water could also be used to cool the steam turbine generators that are involved in parabolic trough power generation and the internal cooling systems in parabolic dish engines.

Environmental Impacts

Widespread CSP implementation has both positive and negative impacts on the environment. The primary negative impact stems from the large amount of land area needed for extensive CSP plants. For example, it is estimated that a 100 MW CSP plant would cover approximately 3.2 km^2 (comprised mostly of the solar field) while a 500 MW combined cycle plant would occupy only around 0.08 km^2 (Stoddard et al., 2006). Additionally, the land which meets the criteria for ideal CSP generation is often located in fragile desert habitat.

Expansion of CSP facilities could benefit the environment by reducing both criteria pollutants and carbon dioxide levels if it displaces current fossil fuel generation capacity. Table 11 below outlines the potential emission reductions from CSP deployment.

Table 11. Estimated emission reduction by CSP plants (Stoddard et al., 2006).

Emission Reduction by CSP Plants					
	Proxy Fossil Plant Emissions Rate		CSP Plant Capacity		
Pollutant	lb/MMBtu	Parts per Million	110 MW (tons/year)	2,100 MW (tons/year)	4,000 MW (tons/year)
NO_x	0.006	2	7.4	156	297
CO	0.004	4	4.5	95	181
VOC	0.002	1.4	2.6	54	103
CO_2	154		191,000	4,000,000	7,600,000
Assumptions: 1) Proxy Fossil Plant assumed to be a combined cycle combustion turbine with a heat rate of 7,000 Btu/kWh. 2) CSP Plants assumed to operate at 40 percent capacity factor.					

CSP has good potential for use in areas with high solar resources, for many reasons. Most notably, most concentrating solar power is available during the daytime, mimicking patterns of electricity demand. In addition, many areas with high CSP potential, such as open, sunny deserts currently remain undeveloped. With no direct air emissions, CSP has little impact on air quality and contributes no carbon to the atmosphere. Finally, CSP technologies have very low operational water requirements and will not further burden already-stressed water resources. Overall, there is great potential for the development of CSP in warm climates worldwide.

Wind Power

Introduction

Wind power currently meets approximately one percent of the world's electricity needs (World Wind Energy Association, 2006). Wind power provides an even greater proportion of energy supplies in some nations: 20 percent of the electricity in Denmark and some areas of Germany and Spain (Sawin et al., 2006). In the U.S., however, it provides less than one percent of the electricity capacity. The U.S. has a current wind capacity of 11,603 MW[11] (American Wind Energy Association, 2006c), 18 percent of the world's capacity. California and Texas, the largest wind power producing states, generate most of this. Many of the wind resources across the world and U.S. are still untapped. For instance, the Great Plains of the U.S. has such large wind power potential it has been referred to as the "Persian Gulf" of wind power (Sawin et al., 2006); (Figure 38).

[11] As of January 23, 2007

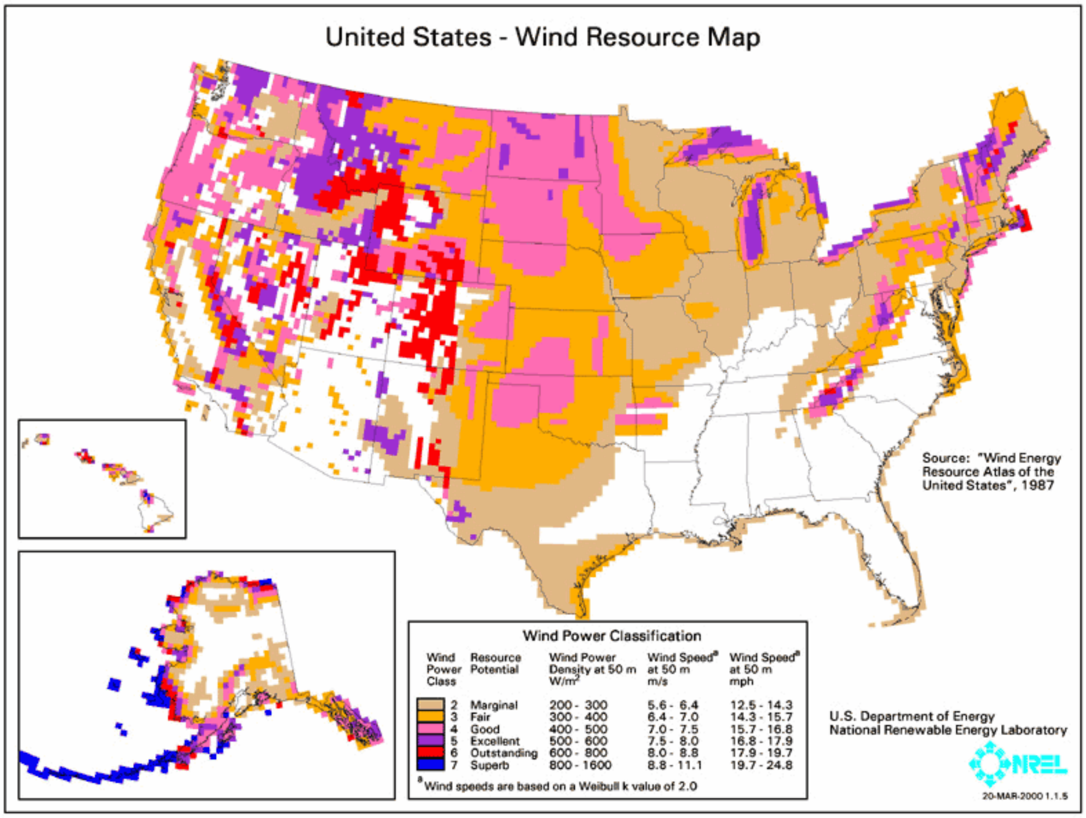


Figure 38. Wind resources for the United States (NREL 2002).

Generation technology

Electricity is generated from wind power by using the mechanical energy of the wind to rotate turbines (Figure 39). A wind turbine can generate between 50 and 300 kilowatt-hours of electricity (California Energy Commission, 2005e). Turbine size can vary based on the application: small turbines (less than 10 kW) can be used for homes and remote site power; intermediate-sized turbines (10 – 250 kW) are typically used for village power, hybrid systems, and distributed generation; and larger turbines (250 to over 2000 kW) are used in wind farms and for distributed generation (Flowers, 2002). The newer, larger turbines used in wind farms and commercial facilities may have blades over 300 feet wide; in comparison, a typical jumbo jet's wingspan is roughly 200 feet (Figure 40).

Turbines sized for utility applications have increased from less than 100 kW in the 1980s to greater than 1,200 kW (Sawin et al., 2006). To produce electricity on a utility scale, several wind turbines are built in a large wind farm. The number of turbines varies depending on the size of the turbines and the farm (e.g. the Westwinds project in Palm Springs, CA has a 43.4 MW capacity with 62 wind turbines, while the High Energy Center in Solano County, CA has 162 MW capacity with 90 wind turbines (AES SeaWest, 2007); (FPL Energy, 2007). Generally, a wind farm will not be developed unless it has an average wind speed of 20.9 km/h (13 mph) (California Energy Commission, 2007b). Electrical output from a wind farm differs from its nameplate capacity: Electrical outputs from wind farms vary throughout the day and year, as a result of seasonal and climatic variations.

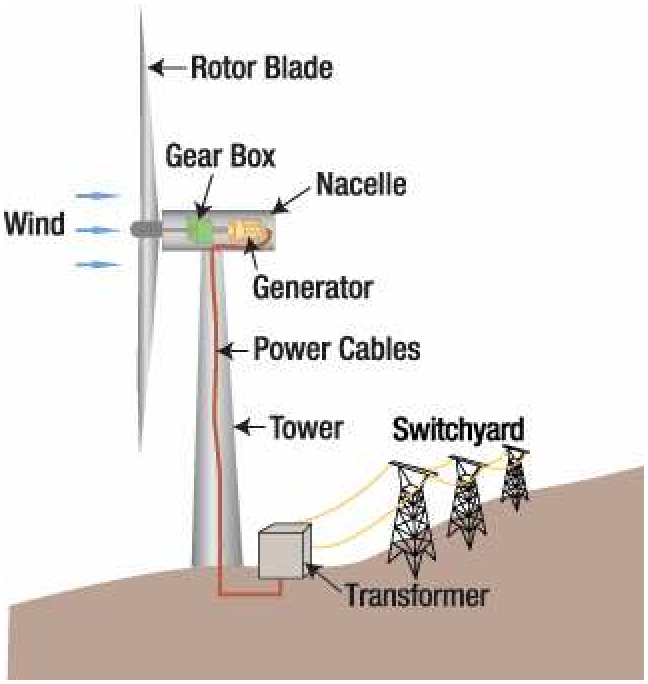


Figure 39. Electricity generation from wind (Tennessee Valley Authority, 2006).

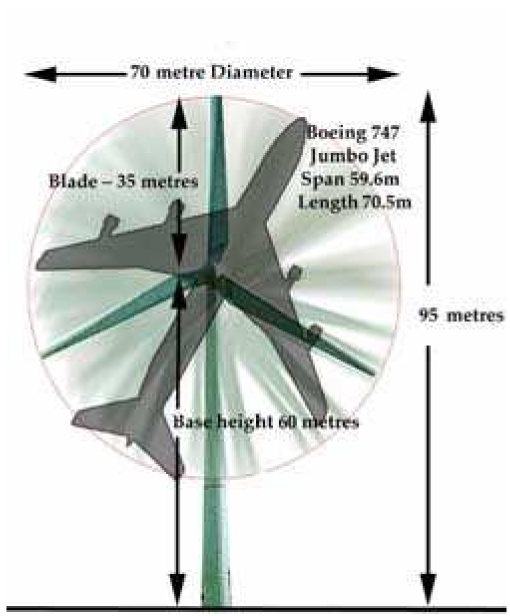


Figure 40. Graphical representation of wind turbine size compared with a 747 jumbo jet ("Sir Walter Scott walkway: Minchmoor and Broadmeadows - wind farms ", 2007).

Water Requirements

Wind power does not use or consume any water during the actual production of electricity. Water may be needed for cleaning of the blades since dust, dirt, and other matter may slowly accumulate on turbine blades and can greatly reduce the turbine's efficiency. At higher wind speeds, dust contamination was found to reduce efficiency by 8 percent (Marzouk, 2006). If wind farms are located in areas that receive regular rain, washing or cleaning of the blades may not be necessary, and therefore, may not consume or withdraw any water. In dry and dusty regions, blades may be washed two or three times a year (Harris, 2006).

Assumptions and Limitations

The main limitation of wind is its availability. As a resource, it is not necessarily located where the electrical demand is located. Additionally, wind is not a constant electrical source; it varies both throughout the day as well as throughout the year.

The California Perspective

California's wind power comes from three main locations: Altamont Pass[12], Tehachapi[13] and San Gorgonio[14] (California Energy Commission, 2007b). In 2005, 4,084,000 MWh of electricity were produced, representing about 1.5 percent of California's gross system power (California Energy Commission, 2007a). Other sites in California could be developed based on the state's wind resources map (Figure 41). By developing additional sites, California could develop an estimated additional 116,800 MW capacity (California Energy Commission, 2005e). Repowering[15] existing sites could provide additional capacity, approximately 470,000 MWh per year (California Energy Commission, 2005e). Many sites were initially developed in the 1980s with turbines smaller in size (by as much as a magnitude) and lower in capacity. Aside from not using additional land, repowering offers an additional benefit of having the transmission infrastructure already in place.

Wind power qualifies as a renewable energy source under California's renewable portfolio standard. Additional wind power is likely needed to meet the future standards, including the 20 percent renewable sources requirement by 2010. Wind is also ideal for meeting California's energy demands since it's seasonal variation correlates with the states energy demands; wind power is strongest during the spring and summer months when energy demand is highest (California Energy Commission, 2007b).

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[12] Located east of San Francisco.
[13] Located southeast of Bakersfield.
[14] Located in Palm Springs, east of Los Angeles.
[15] Repowering refers to the physical replacement of older turbines with new, more efficient turbines.

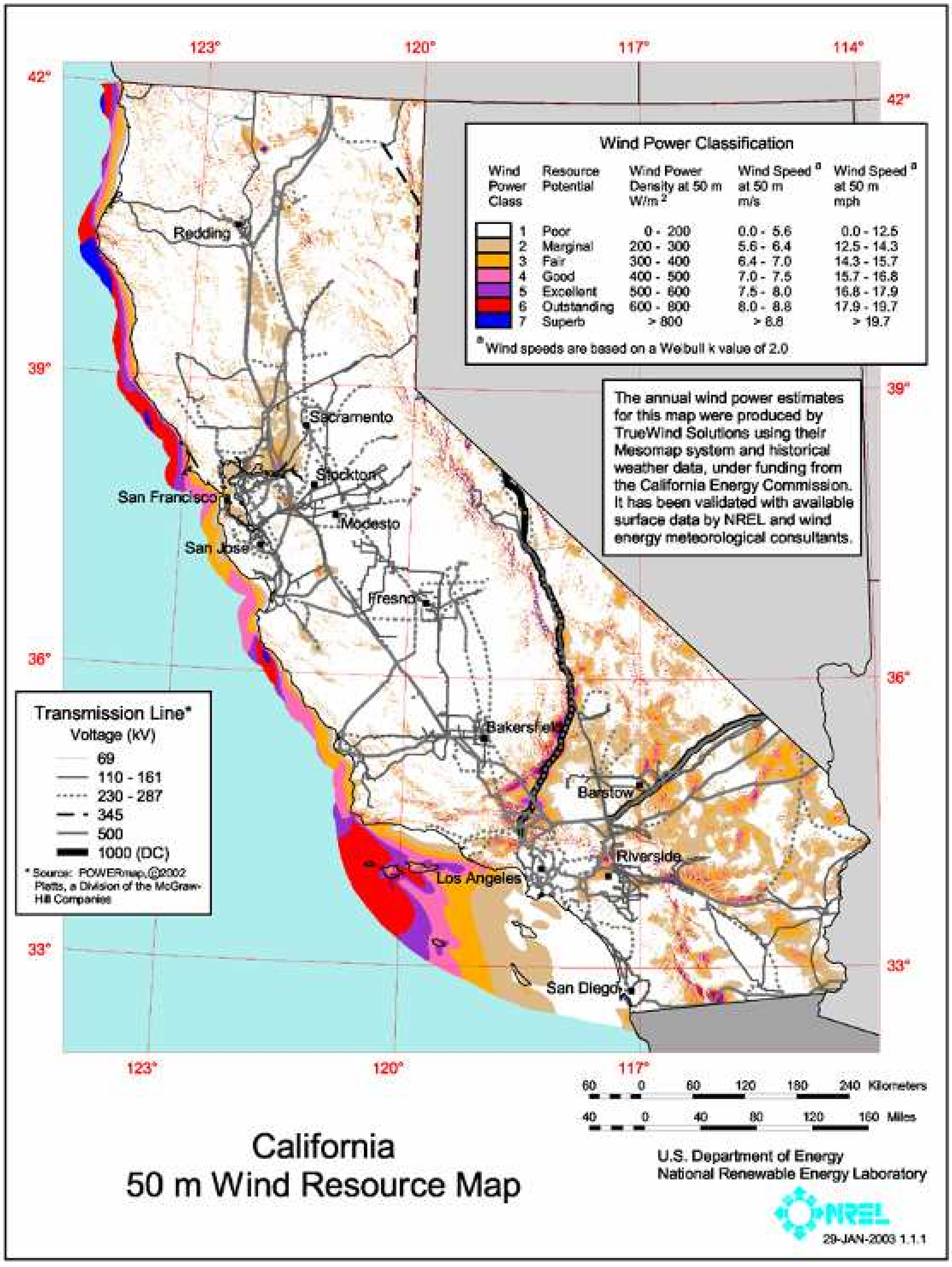

Figure 41. California wind resources (NREL, 2003).

Opportunities to Use Non-Potable Water

Washing turbine blades constitutes the only water use in wind power-based electricity production. These washings maximize output efficiency by ridding the blades of dust and/or bugs which can increase drag, decreasing efficiency. Non-potable water should be applicable for this purpose. Wind turbines can be located on farms and ranches, which could restrict non-potable water use depending on location and land and/or crop type (due to health and safety concerns). While reclaimed or recycled water could be appropriate to wash the turbines, it may logistically be infeasible due to the remoteness of most wind farms and the lack of readily available sources.

Environmental Impacts

Wind power farms can occupy as much as 24.3 hectares/MW (60 acres/MW) (Sawin et al., 2006). Wind farms in the U.S. are often located in the least populated areas due to the resource availability. Thus, the wind farm, related roads and transmission lines often take over previously vacant open space. The land used for wind turbines, however, can serve other functions: for example, land under wind turbines can be used for farming and ranching, thereby not impacting open space. Another environmental concern is the often-fatal danger to birds. To mitigate this, newer wind turbines are usually larger and have more slowly rotating blades, decreasing bird deaths. Properly locating wind farms (i.e. out of migratory bird flight paths) can also reduce the number of birds killed. Some argue, however, that housecats, vehicles, cell phone towers, buildings and habitat loss pose far greater hazards to birds than wind turbines (Sawin et al., 2006). Other areas with plentiful wind resources are located just offshore, often favorably close to major urban centers. Due to concerns about the impact on aquatic species and scenic views, however, most of the offshore potential will not likely be tapped.

Noise from wind turbines has also been expressed as an environmental concern and impact. The first turbines from the early 1980s could be heard as much as a mile away. Today, the noise has been substantially decreased; from a distance of 228.6 to 304.8 meters (750 to 1000 feet, the loudness has been compared to that of a refrigerator (American Wind Energy Association, 2006a).

The operation of a wind farm has no other environmental impacts such emissions, other pollution, or waste products.

Emerging Technologies

Numerous technologies are now emerging onto the market, and may contribute significantly towards meeting future electrical demands both in California and around the world. While an exhaustive list of technologies could be discussed, we examine a select few in this section: fuel cells, FutureGen, and hydrogen.

Fuel Cells

Fuel cells use the chemical energy contained in hydrogen gas to generate electricity. Fuel cells are comprised of a pair of catalyst-covered electrodes, which are separated by an electrolyte, often a moist gel-like layer. When hydrogen is fed into the fuel cell, it encounters the negatively charged anode, and the molecules release protons and electrons. The protons can migrate through the electrolyte to the positively charged cathode where they react with oxygen to form water. The electrons, however, are unable to pass through the electrolyte, and are forced around the cathode, creating an electrical current. When pure hydrogen is used, the only byproducts of this process are water and heat (USDOE, 2006b). Different types of fuel cells are classified primarily by the type of electrolyte they employ. Fuel cells can be stacked and combined to meet widely ranging power demands.

Because fuel cells operate at low temperatures (approximately 80ºC), they require less cooling. While a large amount of information on water management in fuel cells is available (for example, too little water can dry out electrolyte membranes, and too much can "flood" the cells), there is no readily available information on the amount of water used consumptively by the fuel cell technologies currently available.

FutureGen

A $1 billion demonstration project sponsored by the U.S. DOE, FutureGen will be the world's first near-zero-emissions fossil fuel plant with a capacity of 275 MW. FutureGen, which should be fully online by 2013, will gasify coal and produce electricity and hydrogen while simultaneously capturing and sequestering carbon dioxide (FutureGen Alliance, 2006). According to researchers at the Bureau of Economic Geology at University of Texas, Austin (2006), the water use for the facility is expected to initially be somewhat higher than the water use of IGCC power plants, which use 40 percent less water than do pulverized-coal power plants (1.4 – 2.0 m^3/MWh versus 2.3 – 2.5 m^3/MWh).

The overall water demand for FutureGen is projected to be around 180,000 gallons a day (McEwen, 2006), or a range of 0.8 to 1.29 billion gallons per year (Bureau of Economic Geology - University of Texas Austin, 2006). One of the reasons that *FutureGen* project will have a higher initial water demand is that it will be used to develop and test new technologies that will ultimately reduce water needs of IGCC plants (Bureau of Economic Geology - University of Texas Austin, 2006). Officials at the proposed site in Texas stress that FutureGen will not compete with local communities for drinking water (McEwen, 2006), as brackish supplies will be desalinated and employed.

Hydrogen

Hydrogen, expected by many to be the fuel of the future, is actually an energy carrier, and not an actual energy source. At the moment, it is most commonly produced by reforming natural gas, though there are several other ways it can be produced (NREL, 2007b). These are: renewable electrolysis of water, gasification of coal or biomass, reforming of renewable liquid fuels such as biofuels, high-temperature nuclear electrolysis or thermochemical water splitting, and finally photobiological or photoelectrochemical processes (USDOE, 2006b).

Hydrogen is commonly discussed in relation to fuel cells as this technology creates electrical energy from hydrogen producing only water and some heat. As mentioned above, hydrogen is simply a carrier of energy and fuel cells are one of the most efficient ways to unleash that energy (USDOE, 2006b). The amount of water needed to produce hydrogen varies with the technique used to produce it. According to John Turner, a principal scientist at NREL, producing 1 kg of hydrogen requires 9 liters of water. The amount of water need to produce one MWh of electricity would then depend on the type and efficiency of the fuel cell (or other technology) used to access the energy in the hydrogen.

Approach

Our analysis of the water inputs into electricity generation (described above) began with the collection and compilation of data from numerous sources. These data, compiled in an Excel workbook, form the basis for our scenario analyses and a web-based tool. Each spreadsheet in the workbook focuses on a primary energy source for electricity generation, and quantifies the water (in cubic meters) required for each step of the electricity generation process, from fuel capture to electrical output. The web-based tool is a user-friendly interface that allows users to quantify the water required for any electricity portfolio.

In addition to creating a web-based tool, we also used our raw data to calculate the overall water use for seven different California electricity portfolios. Each scenario of future power generation includes a different combination of primary energy sources and generation technologies.

Research Design

All mainstream renewable and non-renewable primary energy sources and electricity generation technologies are included in the workbook. The non-renewable primary energy sources include coal, natural gas, nuclear fuels, and oil. The renewable energy sources include biomass, geysers, sun, water (hydropower), and wind. We collected data for every primary energy source at each step of the energy generation process,. These steps include irrigation (for dedicated energy crops), mining, transportation, processing (fuel conversion), cooling, cleaning, and other technology-specific applications. Not all forms of electricity generation require water in each step; in fact, many require water in only two or three steps. We also collected data for different technological options for each primary energy source. For example, within coal, fuel conversion technologies include both combustion and gasification; for each of these, various methods of cooling such as once-through, recirculating wet, and dry cooling can be used. Finally, high and low estimates of water withdrawals and consumption are included for each technology. For a given technological option, pairs of high and low figures are not necessarily provided by the same source, but rather, represent the highest and lowest figures found in the data collection process.

Data Collection

Water input data for the various energy sources, technologies, and processes came from a variety of sources, including literature reviews, government sources, and primary research. Data collection for this analysis relied primarily on field experts, energy generators, industry representatives, and non-governmental agencies.

Data Collection Assumptions

We made several assumptions when collecting data for our analysis, and drew discreet boundaries of our analysis. This analysis includes the water inputs from primary energy source to electricity generation, but does not include a full life cycle assessment (LCA) of the electricity generation process for each primary energy source. For example, the water required for the mining of coal was considered, but water needed to produce the silicon for the photovoltaic panels for solar energy was not included. In the first case, the mining is related to the primary energy source, coal. For the latter example, the sun is the primary energy source for solar power, not silicon. Thus, the scope of this analysis is limited to the primary energy source (e.g. coal or solar rays), and not the infrastructure required to support electricity generation. Similarly, we did not consider the water needed to build a coal-fired power plant.

Other key assumptions relate to the water required, and distinctions made between withdrawal and consumption. We assumed that the quality of the water returned to its source after withdrawal and use is unimpaired by the electrical generation process and can be reused. Specific generation types and technologies required additional assumptions. These assumptions are listed in Table 12.

Table 12. Assumptions made for the various primary energy sources and electrical generation technologies to quantify the water inputs into electricity generation.

Technology	Assumptions
Coal	▪ A typical coal plant is 500 MW (Feeley et al., 2005). ▪ All process blowdown streams are treated and recycled to the cooling tower.
Natural Gas	▪ Conversion efficiency of 36 percent (from thermal to electric

& Oil	Joules) (Gleick, 1994). ▪ Conversion efficiency of 60 percent (from thermal to electric Joules) for combined cycle plants (Oman, 1996).
Oil Shale & Tar Sands	▪ Calculations assume that one barrel of crude oil (equivalent to 42 gallons, or 0.159 m^3) has an energy content of 1.7 MWh. ▪ Water use estimates are for a 50,000 barrel per day facility. ▪ Water withdrawals were equal to water consumed. Literature reference described all water as consumed, and did not distinguish separate figures for withdrawals (Chan et al., 2006). The quality of the water after use may make it is unusable, and effectively consumed. ▪ "Other" uses include water for disposal and revegetation, dust control during extraction, plant utilities, and on-site power needs (Chan et al., 2006).
Nuclear	▪ Nuclear plants operate at 89.4 percent capacity. (Based on the 2005 U.S. nuclear power plant average) (USDOE - EIA, 2005) ▪ Conversion efficiency of 31 percent (from thermal to electric Joules) for converting uranium to electricity. This efficiency was referenced for light water reactors (LWR) with cooling towers (Gleick, 1993), and assumed to be similar for reactors with varying cooling technologies. ▪ Uranium comes from either surface or underground mining. ▪ BWR (boiling water rector) and PWR (pressurized water reactor) reactors represent the majority of current and new reactors for the U.S. and world, all other reactor technologies are excluded from our analysis.
Hydroelectric	▪ "Run of river" facilities do not impound water or increase rates of evaporation (above natural levels); therefore, we attribute no consumption to run of river facilities. ▪ Locating turbines in aqueducts does not increase existing rates of evaporation. Evaporation (consumption) occurs along aqueducts, but we assume that the primary purpose of these aqueducts is for water supply delivery, *not* hydroelectric power generation. We do not, therefore, attribute any evaporative losses to electricity generation.
Geothermal	▪ Geothermal fluid is not considered in our analysis because its high temperature and unique composition of dissolved solids largely prevent its use in other areas (Reed & Renner, 1995). ▪ Geothermal plants operate at 90 percent capacity (Kagel et al.,

	2005).
Bioenergy	▪ Estimates of water withdrawals and consumption represent "water use efficiency". This figure represents consumption. Actual irrigation (and subsequently, withdrawals), may be much higher, depending on the efficiency of the system. Low and high estimates of withdrawals and consumption reflect varying rates of evapotranspiration from different climates. ▪ The "biomass-based steam plant" has 23 percent conversion efficiency and high heating value (HHV) at 20 GJ/Mg (Berndes et al., 2001); (USDOE - EIA, 2007a). ▪ The "improved biomass-based steam plant" has 34 percent conversion efficiency and a HHV of 20 GJ/Mg (Berndes et al., 2001); (USDOE - EIA, 2007a). ▪ Water use data includes boiler feed water requirements but *not* wet scrubbing. Steam from the steam cycle is injected into the gasifier. Estimates assume a conversion efficiency of 36% and a HHV of 20 GJ/Mg for a gasification-based combined cycle (Berndes et al., 2001); (USDOE - EIA, 2007a). ▪ Water requirements for landfill gas facilities are comparable to those for conventional natural gas facilities. All data are taken from conventional natural gas facilities. ▪ There are no processing water needs [landfill gas facilities often produce additional water by drying the captured gas]; the processing water needed to produce energy from conventional natural gas is used in the pumping process. ▪ Figures assume no transportation costs, as energy is typically produced on-site (with landfill gas generation).
Solar	▪ Power towers require about as much water for mirror cleaning as the parabolic trough plants as both technologies require a large field of mirrors. ▪ The amount of water used for washing the mirrors of parabolic dish-engines is functionally zero as the mirror surface is much smaller than for the other two CSP technologies. ▪ A large PV plant uses the same amount of water per MWh as distributed, or rooftop, generation.
Wind	▪ Turbines are washed three times a year (based on operations at Westwinds, Palm Springs, CA (Harris, 2006). ▪ A washing consumes 0.151 m^3 per turbine (based on operations at Westwinds, Palm Springs, CA (Harris, 2006). ▪ Wind power has a capacity factor of 30 percent. This assumption is based on the inconsistent patterns of wind and an industry

	reference approximating an average range of 30-35 percent of rated capacity throughout the year (American Wind Energy Association, 2006c).

Life Cycle Assessment (LCA)

Life cycle assessment (LCA) can help identify the full resource costs and environmental impacts of a product. Initially developed for the energy sector in the late 1960s, LCA is now used widely in industry and the environmental field. LCA identifies the resources required for the entire life of a product, including disposal. This "cradle to grave" approach can be applied in different ways. Its most basic application is in identifying the total resources required for product development; more specific applications may include identifying the pollutants or greenhouse gases emitted during a product's life.

In order to provide a thorough analysis of the water required for energy generation, one must take a life cycle assessment approach. Energy generation requires water in numerous steps, including mining (or harvesting) of the resource, processing, cooling, and disposal. In addition, water is required to construct capital equipment, such as thermoelectric plants, hydroelectric dams, or solar panels; to build roads or pipelines for transporting the resource; and to dismantle generating facilities at the end of their lifespan. From an even broader perspective, water is required to construct mining equipment and provide fuel for their engines, to transport steel and facility materials, or in the case of biomass, to produce fertilizers. Clearly, an analysis of the water required for energy generation must have discrete, defined boundaries.

The boundaries of this analysis were restricted to the primary, direct uses of water for energy generation. Thus, the analysis includes water for mining, harvesting, processing, cooling, and disposal. Subsequent sections describe these uses and processes for the different energy generation technologies more thoroughly. A literature review revealed substantial research into the impacts of energy generation (for example, on air quality, greenhouse gas emissions, and other resources), but notably little information on the water required for energy generation. We acknowledge that omitting the water used in facility construction and other segments of the energy generation process is a gap in our analysis, and recommend it be addressed in further research. In many types of energy generation, however, we hypothesize that the majority of water consumed and withdrawn occurs during the mining, processing, and cooling phases, and not in the facility construction. Notable exceptions to this hypothesis may include solar panels and massive cement facilities such as hydroelectric dams. An additional consideration is that the construction of solar panels, wind turbines, or other facility equipment does not necessarily occur in the same geographic region where the energy is generated, and therefore may affect the water resources of a different region (one that, ideally, is not water-limited).

Verification

We verified the validity of our collected data by comparing our projections of water withdrawals with USGS estimates for four counties in California. The USGS estimates are based on power plants' self-reported water withdrawals, in response to a survey completed by the California Department of Water Resources in 2005. Due to the 35 percent response rate, the data were extrapolated to estimate total withdrawals. The USGS withdrawal data was reported by county; in California, estimates were only available for 7 out of 58 counties, thus limiting the data available for verification. Additionally, the USGS estimates only include water withdrawn for thermoelectric generation, and do not include the other water requirements included in our data collection, such as mining, transportation, or cleaning requirements.

To compare our data with the USGS estimates, total electricity generation for a county was estimated by first compiling a county electricity profile. Using the California Energy Commission's (CEC) database of power plants in California, a profile including the fuel type, conversion technology, and size of power plants in a county was identified. Not included in their database, however, is the type of cooling technology employed. Assumptions regarding cooling technologies were made based on the plant's location, conversion technology, and year of construction.

> By definition the capacity factor is the ratio of actual net energy production to the product of the power rating times the calendar time interval of interest.
>
> $$\text{Capacity Factor} = \frac{\text{Net Energy Generated}}{\text{Power Rating x Time}}$$

Next, the amount of electricity generated for the given profile was calculated. While the capacities of the various power plants are provided by the CEC database, the amount of electricity generated was not included. Generation of electricity was then estimated using average capacity factors, determined in our literature review, for the various power plants within the electricity profile.

The amount of water used by the given county was then calculated using the collected data on water use for various electricity generation technologies and the estimated amount of energy generated. This calculated amount of water withdrawals was then compared to that estimated by the USGS, to complete the verification.

We verified the model using Monterey, San Bernardino, San Diego, and San Luis Obispo counties. These counties were chosen based on available USGS water withdrawal data as well as being able to represent the full portfolio of electricity generating technologies. The specific assumptions made for the various verifications are listed in Table 13.

Table 13. Assumptions for model verification.

	San Bernardino	Monterey	San Luis Obispo	San Diego
Coal	Assumes surface mining, no washing, pulverized slurry, conventional pulverized combustion, recirculating cooling, wet cooling	N/A		
Geothermal	N/A			
Hydroelectric	Not included in verification because hydroelectric withdrawals are not included in USGS estimates			
Nuclear	N/A	N/A	Assumes PWR with once-through cooling. Water required for mining is not included in figure (because uranium is not mined in the county)	
Oil	N/A			
Oil/Gas - baseload[16]	Assumes combined cycle, wet cooling, no inlet fogging, all natural gas	Assumes these plants are combined cycle, once-through cooling, all natural gas		
Oil/Gas - peakers[17]	Assumes simple cycle, steam turbine, wet cooling	Assumes simple cycle, steam turbine, once-through cooling		
Solar	Assumes solar parabolic trough	N/A		
Wind	N/A			Assumes large sized wind farm
WTE	Assumes all WTE is landfill gas, simple cycle, with water requirements are the same as for natural gas			

N/A: not applicable (fuel type not part of county's energy portfolio)

[16] Assumes that 40 percent of oil/gas plants are baseload plants; the remaining 60 percent of oil/gas plants are peaker plants
[17] Assumes that all plants are operation at 100 percent capacity, except "peaker" plants which operate at 30 percent capacity

Scenario Development and Water Requirement Estimates

To estimate statewide freshwater requirements, we developed ten scenarios based on several different possible California energy portfolios. The scenarios are as follows:

1. Current portfolio (based on 2005 generation data)
2. 2010 with 20 percent renewables (based on RPS requirements)
3. 2020 with 33 percent renewables (based on RPS goal)
4. 2030 with 33 percent renewables (based on same portfolio as Scenario 3, with increased overall electricity generation to meet 2030 demands)
5. 2020 with a fossil fuel-focused approach
6. 2020 with a technology-focused approach (dry cooling and IGCC)
7. 2020 with a primary energy-focused approach (water-efficient, low-carbon, minimal land use)
8. 2020 with a primary energy AND technology-focused approach
9. 2020 with a technology focused approach, including coastal plants (on wet recirculating cooling)
10. 2020 with a technology focused approach, including coastal plants (on dry cooling)

Scenarios 1-8 examine only freshwater requirements; they do not include seawater or brackish delta water use for cooling coastal power plants. In addition, water required for hydroelectric generation (both withdrawals and consumption) is excluded from all ten scenarios. We exclude these sources of water for different reasons. Freshwater represents a limited commodity in California, and while seawater withdrawals may have significant impacts on marine ecosystems, seawater does not represent a limited resource. Hydroelectric water withdrawals represent a profoundly different metric, and are not easily compared to other forms of water withdrawals for electricity generation.

Generation data for all scenarios was obtained from the CEC and based on 2005 generation levels and CEC projections for future electrical demands. Draft projections for the renewables within the overall portfolio were obtained from the Intermittency Analysis Project (IAP) by CEC's Public Interest Energy Research (PIER) branch (Yen-Nakafuji & Porter, 2006).

The current water footprint of California's electrical utilities is illustrated in the first scenario, The remaining scenarios were chosen and developed to attempt to reflect some of California's different energy portfolio options and their water implications. Scenarios 2-4 focus on California's RPS. Scenarios 5-8 represent alternate scenarios to Scenario 3 (2020 with 33 percent renewables). Scenario 5 represents a portfolio reflecting an increasing number of natural gas and coal facilities, which has been the current trend due to the cost efficiency of those types of electricity generation. Scenarios 6-8 represent water-efficient approaches to a future energy portfolio. While Scenario 6 alters the mix of primary energy sources, Scenario 7 focuses on advanced, water-efficient conversion technologies, such as dry cooling and IGCC. Scenario 8 then considers both water-efficient primary energy sources and water-efficient technologies.

Scenarios 9 and 10 analyze the water use implications if coastal natural gas plants convert to freshwater based cooling systems. Scenario 9 examines the freshwater impacts if the plants use wet recirculating cooling, whereas Scenario 10 examines the water use impacts if dry cooling is employed.

The development and calculations for each scenario include several embedded assumptions. The general assumptions for plant type and cooling technologies were the same as those used in the model verification. Additional assumptions had to be made for future scenarios as to how energy portfolios might change. For instance, in 2020, if more renewables become available to meet demand, other energy sources will be used less. Questions such as these are addressed with the assumptions are listed in Table 14.

Results from the scenarios focus on freshwater requirements for electricity generation, with the exception of scenarios 9 and 10. Freshwater is focused on because it is a more limited resource. While the current trend is to build power plants inland, and to wean coastal plants off of their dependency on the ocean for once-through cooling, it is primarily due to marine impact concerns not due to lack of saltwater supply. We attempt to assess the impacts of converting these facilities to wet recirculating or dry cooling in Scenarios 9 and 10.

Table 14. Assumptions for energy portfolios.

Scenario	Assumptions for Energy Portfolios
1. Current portfolio (based on 2005 generation data)	No assumptions - used 2005 CEC data on electricity generation
2. 2010 with 20 percent renewables (based on RPS)	No assumptions - used CEC's projected energy profile and electrical demand
3. 2030 with 33 percent renewables	1. RPS portfolio mix from 2020 (33 percent, and breakdown between generation types); 2. Amount of ocean-cooled natural gas generation remains the same; 3. Increases percent of energy from coal by 2 percent, since the percent contribution to the overall portfolio from ocean-cooled natural gas decreases.
4. 2020 with 33 percent renewables (based on RPS goal)	1. Coal percent contribution is the same as in 2005, due to the ready availability of coal and its cheap price; 2. Hydroelectric and nuclear power decrease by 4 and 5 percent, respectively; a result of decommissioning, and aging of facilities (and lack of new facilities being built); 3. The oil and natural gas percent contributions decrease to 25 percent of total generation – due to pricing more likely to fluctuate and the lack of major U.S. reserves; 4. The amount of coastal generation is kept the same, but the amount generated from inland freshwater facilities decreases.
5. 2020 with a fossil-fuel focused approach	1. All types of generation stay the same except fossil fuels - natural gas and coal, which have to increase by 50 percent in order to provide sufficient power.
6. 2020 with a technology focused approach	1. Same energy portfolio as the 2020 RPS-based mix; 2. Dry cooling for coal, natural gas, geothermal, and solar thermal; 3. Coal is converted with combined cycle gasification (IGCC); 4. Coastal plants are excluded.
7. 2020 with water-efficient primary energy sources that have minimal carbon and land use impacts	1. Wind resources at build-out, solar energy from only PV on rooftops; biofuel energy comes only from landfill or waste products; 2. Nuclear power and hydroelectric power stay the same; 3. Coal and geothermal are excluded due to higher water needs; 4. Coastal plants are excluded.
8. 2020 with water efficient primary energy sources and water efficient technology	1. Water efficient primary energy sources are emphasized; 2. Dry cooling for coal, natural gas, geothermal, and solar thermal; 3. Coal is converted through combined cycle gasification (IGCC); 4. Coastal plants are excluded.

9. 2020 with a technology focused approach, including coastal plants (on wet recirculating cooling)	1. Same energy portfolio as the 2020 RPS-based mix; 2. Dry cooling for coal, natural gas, geothermal, and solar thermal; 3. Coal is converted with combined cycle gasification (IGCC); 4. Coastal natural gas plants use freshwater for wet recirculating cooling.
10. 2020 with a technology focused approach, including coastal plants (on dry cooling)	1. Same energy portfolio as the 2020 RPS-based mix; 2. Dry cooling for coal, natural gas, geothermal, and solar thermal; 3. Coal is converted with combined cycle gasification (IGCC); 4. Coastal natural gas plants use dry cooling.

Web-based Tool Design

The web-based tool was created using the Excel workbook of collected data on water inputs for electricity generation. This tool, like the workbook, provides a range of high and low values for water withdrawals and consumption per MWh of electricity generated. The tool is designed to be universally applicable; providing accurate output for users in all locations, and electricity generation portfolios of all types.

With the web-based tool (see Figure 42 for screen shot), a user can determine the water requirements of different generation portfolios. To do this, the user inputs an unlimited number of lines, each of which includes expected electricity generation (in MWh) for a particular facility, the primary energy source used (coal, sun, natural gas, etc.), and more specific generation technologies. The specific conversion technologies are chosen from a series of responsive menus that reflect to previous menu selections. For example, if a user inputs 80 MWh of coal based generation, the webtool prompts them to select the type of coal, and if it is extracted by surface or underground mining. The user then chooses between washed or unwashed coal, combustion method, and the cooling technologies employed by the facility. Users can add input lines for additional generation facilities. For a more detailed, step-by-step guide to how the tool works, please see the user's guide in Appendix E: Users' Guide for the Energy-Water Calculator

Programming was done with Java by a graduate student from University of California, Santa Barbara's Department of Computer Science, Nikolay Laptev.

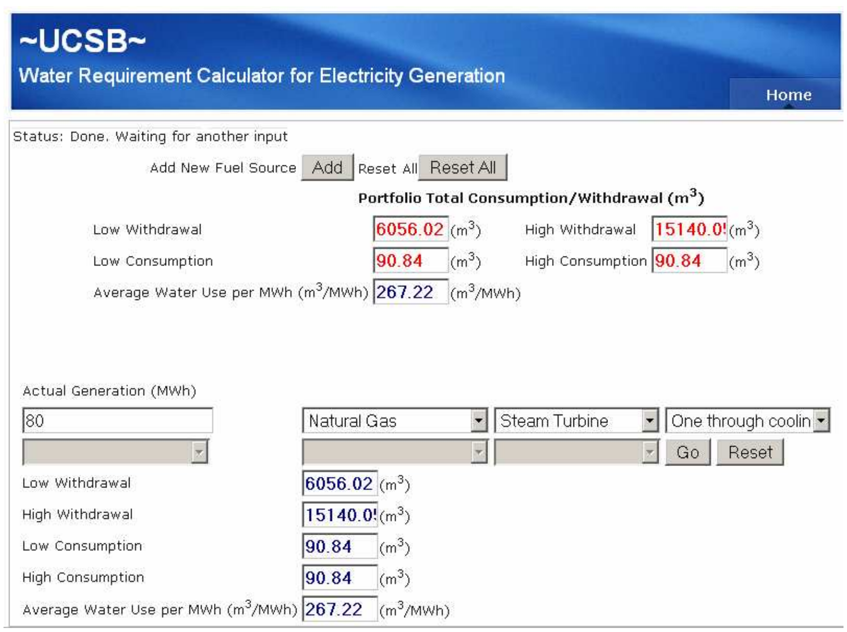

Figure 42. Snapshot of web-based tool (interactive tool available at http://fiesta.bren.ucsb.edu/~energywater/).

Results

Data Collection

The water required for electricity generation varies substantially, depending on the primary energy source and the technologies employed (Figure 43). The following sections present a more detailed assessment of the water requirements for each primary energy source. These sections are not a comprehensive description of all results; rather, they reflect the most important findings. The complete dataset of water requirement for each energy source is attached as Appendix B. Note that the following graphs use different scales on the y-axis; this difference allows for better comparison of the various technology choices within a primary energy source.

In general, the factor responsible for the greatest impact on the water required for electricity generation is the type of cooling technology utilized. Biomass and geothermal energy are the two main exceptions to this trend. Water requirements for the energy sources and cooling technologies are described in more detail below.

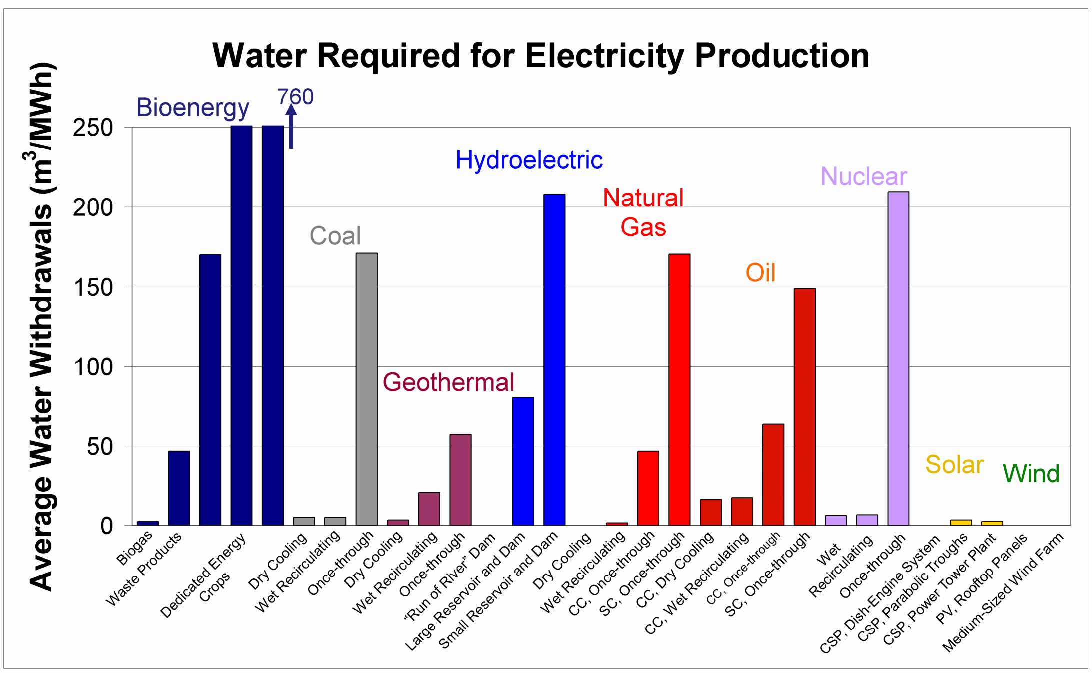

Figure 43. Snapshot of water withdrawals (averages) required for electricity generation for all primary energy and a series of cooling technologies.

Non-renewable Fuels

Non-renewable sources of energy, such as coal, natural gas, oil, or nuclear fuels, have comparable water requirements. The amount of water required depends primarily on the type of cooling technology employed. Once-through cooling for coal, natural gas, and oil plants, for example, requires 76 – 189 m^3/MWh of electricity generated. Most of this water is returned to the original source, with only approximately 1.1 cubic meters of water consumed. Nuclear power plants require slightly more water, at 95 – 227 m^3/MWh. Other cooling technologies, such as recirculating wet cooling and dry cooling, require the withdrawal of substantially less water (1.9 – 4.5 m^3/MWh and 0.1 – 0.23 m^3/MWh, respectively), but consume a higher portion of the withdrawn water. Dry cooling, by contrast, consumes almost 100 percent of all withdrawn water. Water withdrawal and consumption rates of hybrid wet-dry cooling systems fall within the rates of purely wet-recirculating or dry cooling systems. While other fuel processing steps, such as mining and washing require some water, these requirements are dwarfed by cooling requirements, which are typically 10 to 100 times larger.

A power plant's conversion efficiency also affects the relative amount of water required for electricity generation from fossil fuels. Combined cycle plants, for example, have a higher rate of energy capture than a conventional steam turbine, and therefore use less water per MWh of electricity generated. The following figures (Figure 44); (Figure 45) reflect water requirements for electricity generation from coal. Once-through cooling withdrawals are substantially higher than other forms of cooling; the two graphs have different y-axes to adequately display the divergent water requirements. These water requirements are comparable to those of natural gas, oil, and nuclear fuels.

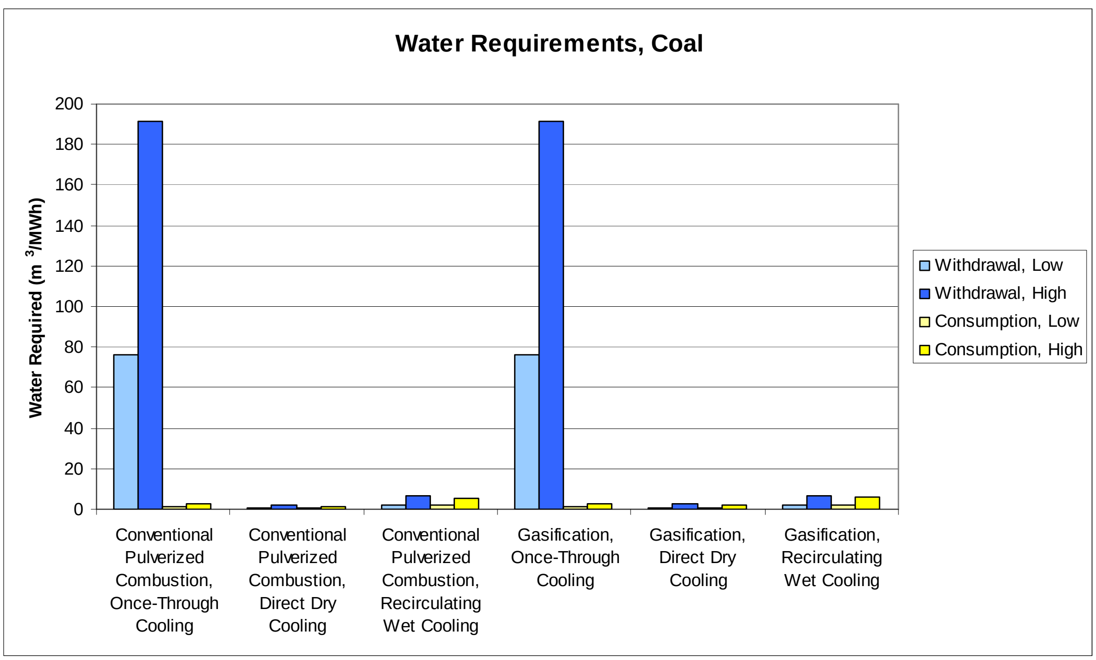

Figure 44. Water requirements for electricity generation from coal. All data include surface mining, washing of the coal, and transport via a pulverized slurry. These figures are comparable to those for underground mining and transport via a log slurry line.

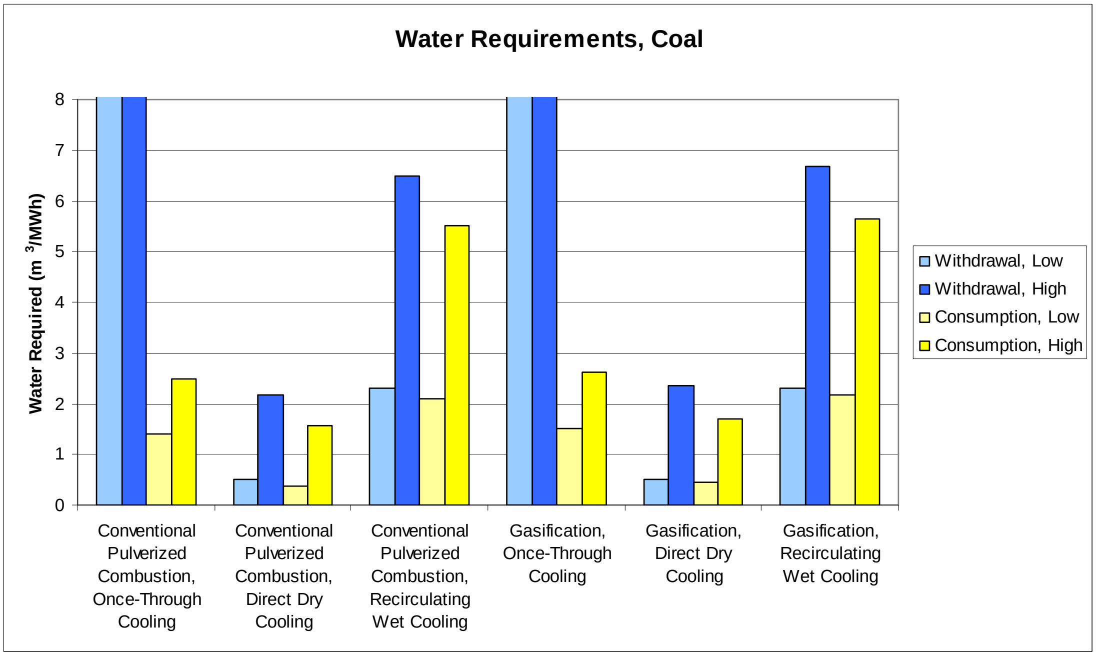

Figure 45. Water requirements for electricity generation from coal. All data include surface mining, washing of the coal, and transport via a pulverized slurry. These figures are comparable to those for underground mining and transport via a log slurry line. **Note:** Different y-axis scale, used to highlight difference in non-once-through cooling technologies.

Renewable Fuels

Bioenergy

Water requirements for generating energy from biomass range significantly. Dedicated energy crops represent the most water-intensive bioenergy resources, regardless of the type of conversion technology employed. Almost all of the water used in generating electricity from dedicated energy crops is devoted to agricultural irrigation. Therefore, the type of crop planted, its irrigation needs (which vary, depending on the growing climate), and the amount of energy stored in the plant's structure heavily influence the water required per unit of electricity produced. As a result, water requirements range from 133 to 1,260 m^3/MWh for dedicated crop based bioenergy generation (Figure 46).

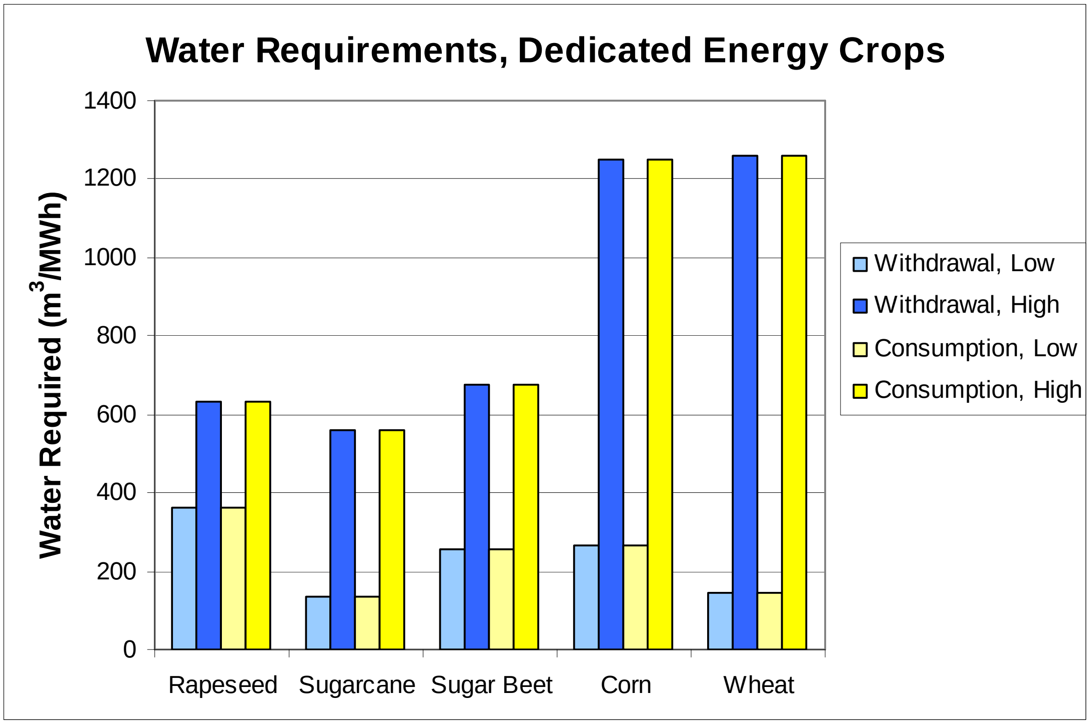

Figure 46. Water requirements of dedicated energy crops**.** The figures above represent a gasification conversion technology, but other conversion technologies (such as steam plants) have comparable water requirements. Water withdrawals and consumption data are based on rates of evapo-transpiration. Inefficient irrigation may lead to much higher rates of withdrawal.

The water requirements of dedicated energy crops dwarf those of other sources of bioenergy. Generating electricity from agricultural waste products or captured biogas (e.g. methane in landfills) only requires 0.1 – 2.5 m^3/MWh (Figure 47).

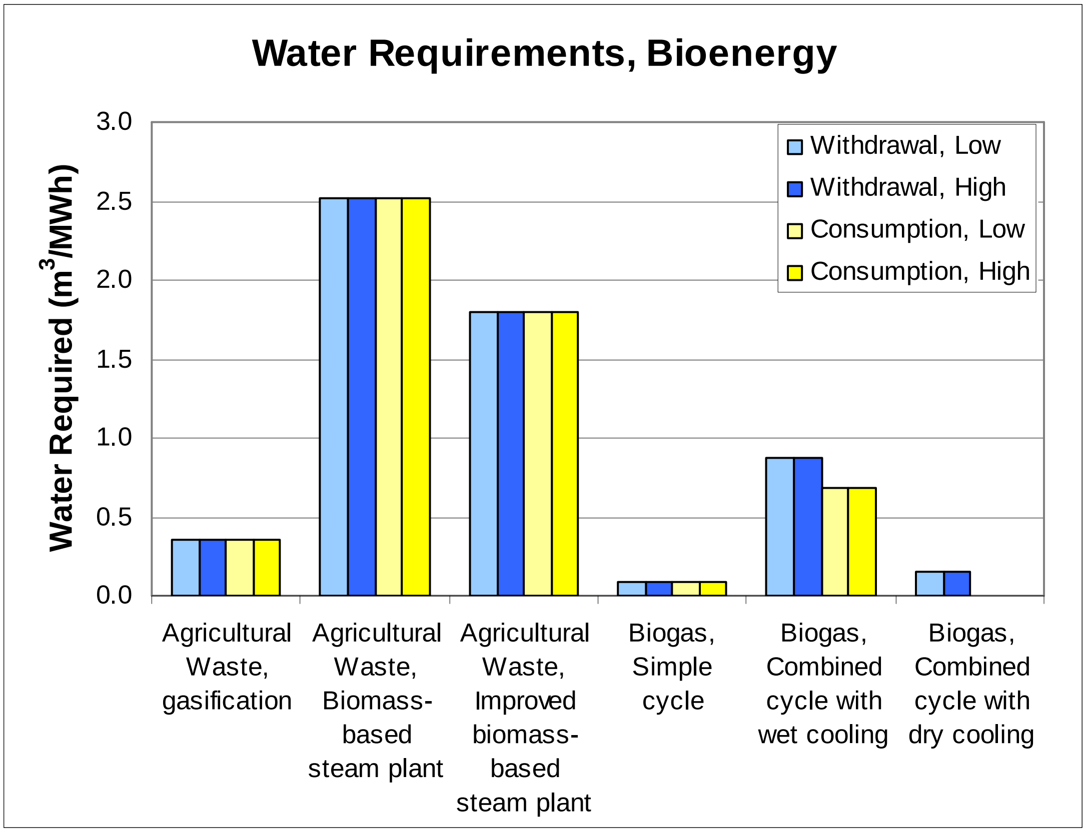

Figure 47. Water requirements for electricity generation from bioenergy sources, excluding dedicated energy crops. Withdrawal and consumption figures reflect both low and high estimates (which are equal in our data). **Note:** Scale on the y-axis differs from Figure 46, above.

Geothermal

As with bioenergy, water requirements for geothermal energy generation vary substantially; this analysis focuses only on external water requirements and ignores geothermal fluid (the water pumped from the geothermal source itself). We ignore these source fluids because in most cases, they contain salts or other suspended matter that largely precludes using them for agriculture, municipal, or other industrial uses, unless advanced desalination technologies are used (Bourcier, 2007). As with conventional forms of energy generation, the largest water requirements are for cooling and condensing steam. The amount of water required can be as high as 54 m^3/MWh, for once-through cooling systems (Figure 48). Some geothermal plants are able to fully rely on condensed geothermal fluid for cooling, and therefore have no external water requirements (Kagel et al., 2005). Additional water requirements may include injection of water from external sources, as is done in The Geysers, in order to maintain steam production and longevity of the geothermal source (Geothermal Research Council, 2003).

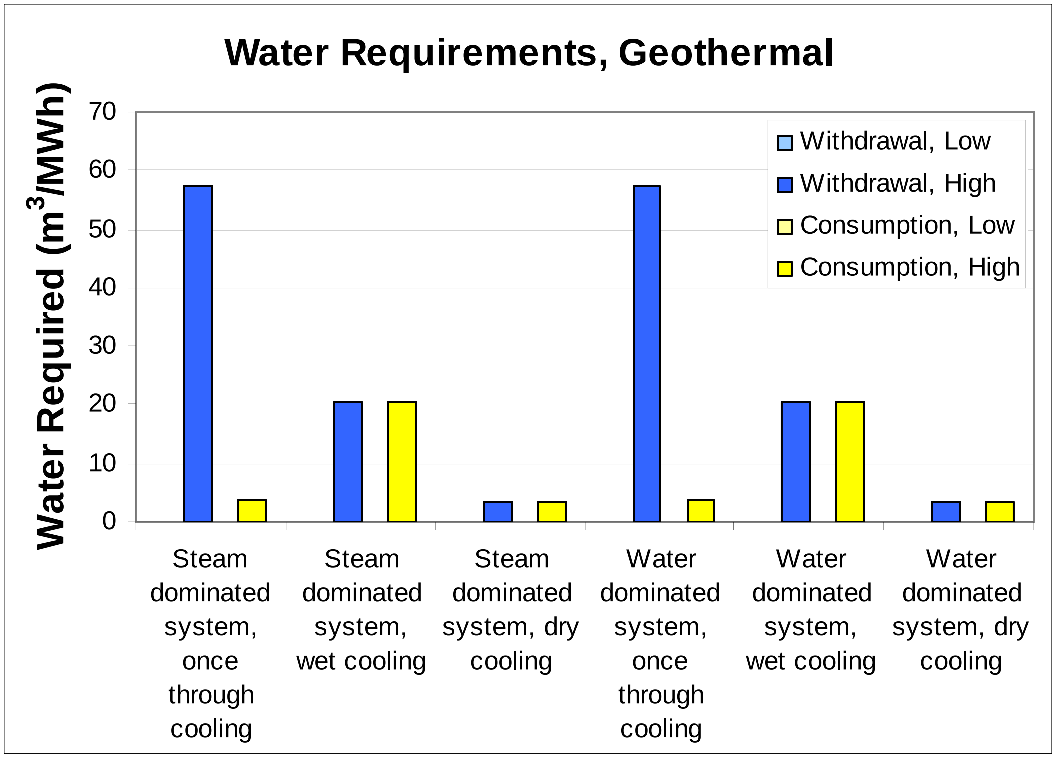

Figure 48. Water requirements from external sources for electricity generation in geothermal facilities. Low estimates of withdrawals and consumption are zero, which assumes that geothermal source fluids are captured and used for cooling or resource recharge.

Hydroelectric

The shape, size, reservoir conditions, and local climate are the primary factors affecting rates of water withdrawal and consumption in hydroelectric facilities (Figure 49). Most notably, consumption represents evaporative losses from reservoirs, which vary dramatically. The most important factors in these losses include the shape of the reservoir and the local climate: a wide, shallow reservoir has greater evaporative losses than a narrower, deep reservoir (Gleick, 1992). Similar to fossil fuel plants, hydroelectric facilities also vary in efficiency. When the dam height of a reservoir is less than the gross static head[18] the facility is more efficient at generating electricity (i.e., they generate more electricity per unit of water flowing through the turbines). The evaporative water losses per MWh, therefore, are lower than those in facilities with a dam height greater than the gross static head.

[18] The gross static head (GSE) is the amount of pressure exerted by a column of water. For hydroelectric facilities, the gross static head is determined by the height differential between the water surface and the turbines. Facilities with long penstocks connecting the reservoir to a turbine typically have a GSE greater than the dam height, while facilities with turbines at the base of the dam have a GSE less than the dam height.

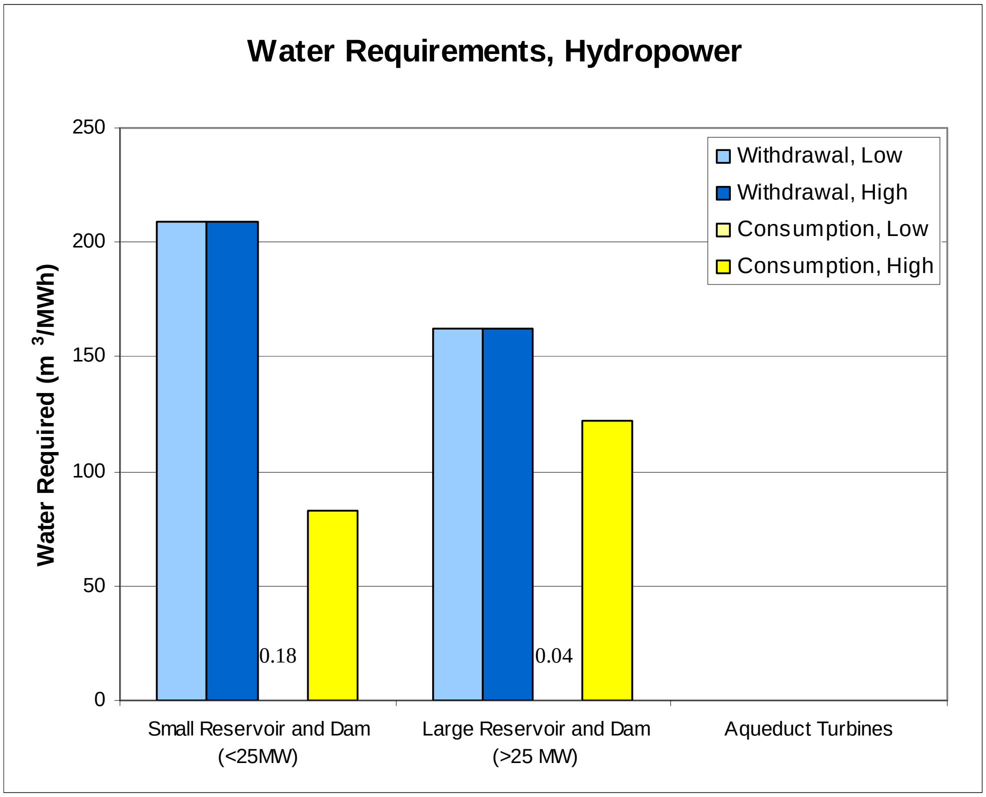

Figure 49. Water requirements for electricity generation from hydropower facilities. Data represents facilities in which the dam height is less than the gross static head. The low estimate of consumption in small reservoirs is 0.18 m^3/MWh and in large reservoirs, 0.036 m^3/MWh. We attribute no additional withdrawals or consumption to water flowing through turbines in an aqueduct.

Solar

The main factor determining water use in solar facilities is the capture and conversion process. Solar thermal facilities (CSP) that use the sun's heat energy to convert water to steam have water requirements comparable to all other forms of thermoelectric generation. As in other thermoelectric technologies, cooling and condensing represents the primary use of water. Solar photovoltaic systems (PV) require water only to clean the panels; the volume required, however, is less than one tenth that needed for thermoelectric generation (Figure 50). Parabolic dish engines and concentrating PV systems have no water requirements at all. In solar facilities, withdrawal is equal to consumption because all water withdrawn is consumed.

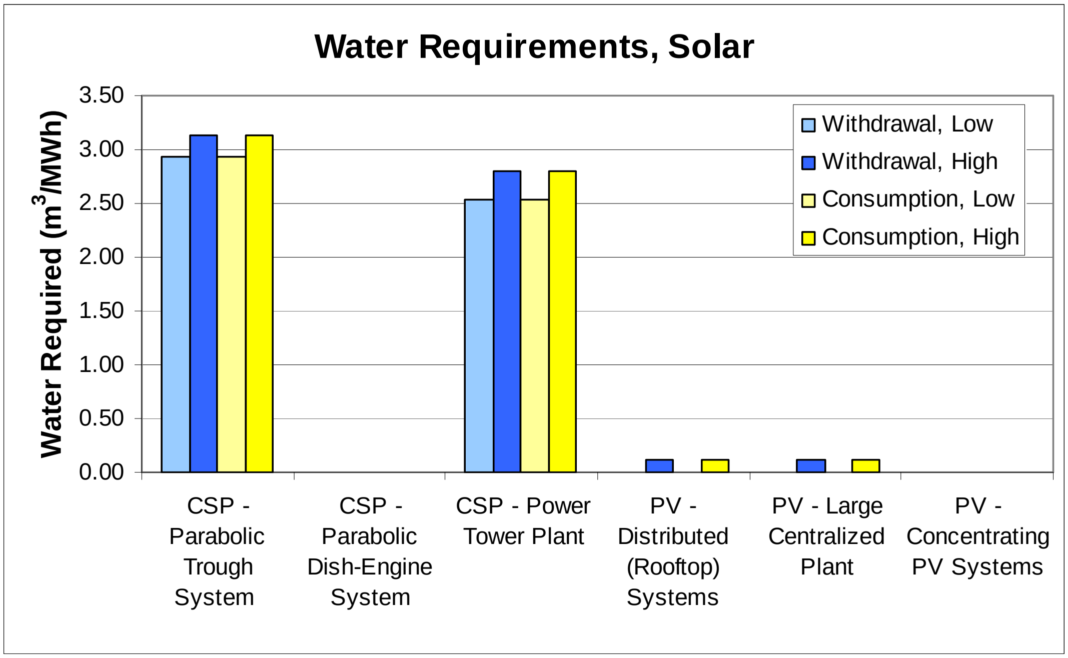

Figure 50. Water requirements for generating electricity from solar facilities.

Wind

Similar to water use in solar PV generation, wind turbines require negligible amounts of water, all of which is used for cleaning the turbine blades. Not all wind farms wash turbine blades, accounting for the low estimates (zero). We assume that all withdrawn water is consumed (Figure 51).

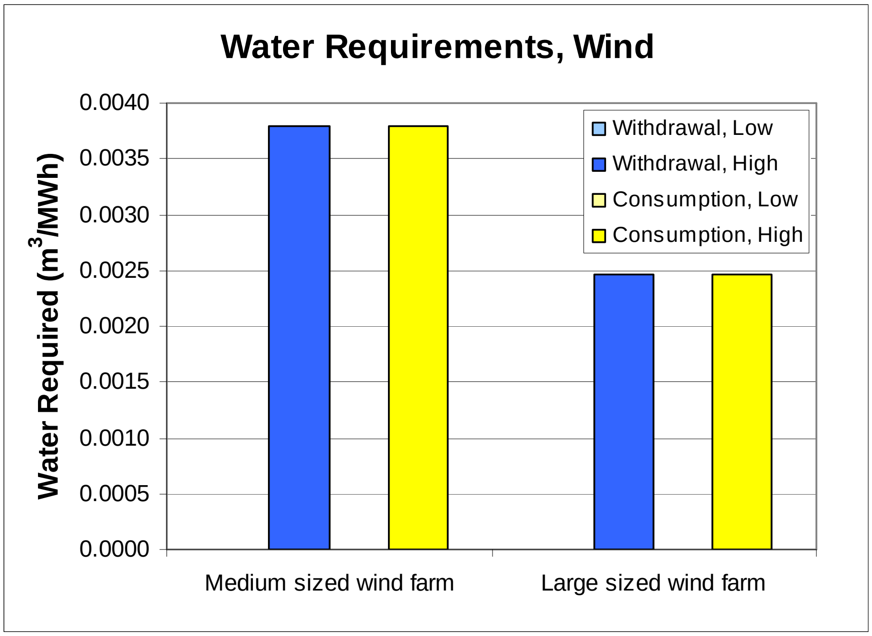

Figure 51. Water requirements for electricity generated from wind power. Low estimates of water withdrawals and consumption are zero, representing wind farms that do not clean the turbine blades.

Verification

To verify our model, we compared our projections with USGS estimates of withdrawals for thermoelectric generation for several counties in California. The USGS's estimates of water withdrawals for the three coastal counties, Monterey, San Diego, and San Luis Obispo, fall within our low and high projections (Figure 52). In these counties, most of the electricity is generated by several large, coastal thermoelectric facilities that rely on ocean water for once-through cooling. For verification purposes, we include these facilities. As noted above, the water required for once-through cooling dwarfs all other water requirements.

San Bernardino County, on the other hand, has a more diverse energy portfolio; in addition to conventional natural gas and coal facilities, the county has several large solar thermal facilities. In general, the water withdrawn for electricity generation in San Bernardino County is significantly less than the water withdrawn in the coastal counties (which is high because of once-through cooling facilities). Our analysis projects annual water withdrawals 5 – 8 times greater than those projected by the USGS (Figure 52); (Figure 53). Several factors may account for this discrepancy, including the basis for USGS estimates, our assumptions, and the water source.

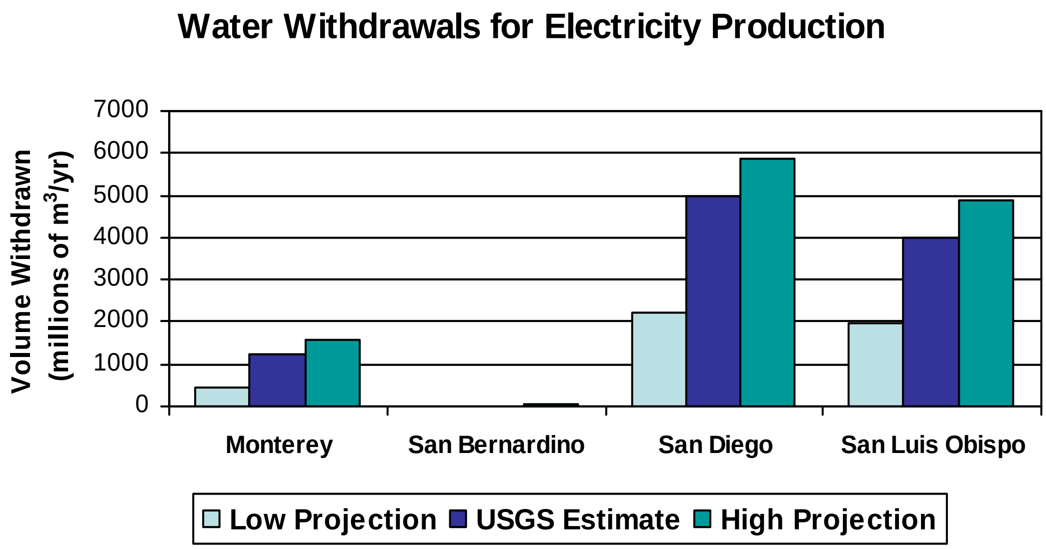

Figure 52. Projected water withdrawals for Monterey, San Bernadino, San Diego, and San Luis Obispo Counties.

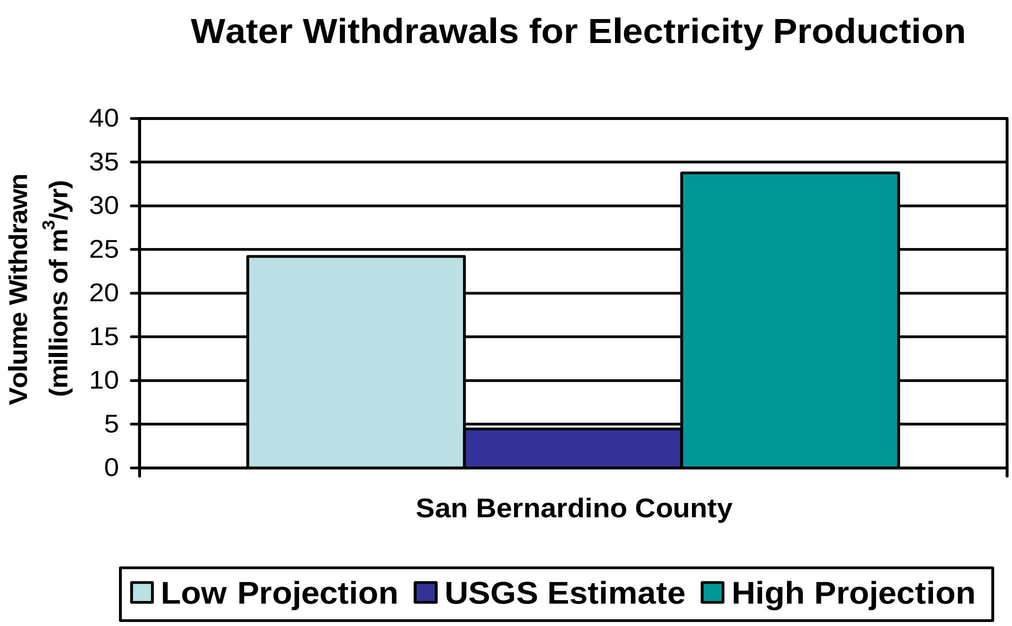

Figure 53. Projected annual water withdrawals San Bernardino County, California. The USGS estimate is compared to low and high projections, which are based on our model. **Note:** The y-axis scale differs from that of Figure 52.

Scenarios

Based on the collected data and the assumptions described in the Approach section, we projected the water withdrawals and consumption for California under several different scenarios.

1. Current portfolio (based on 2005 generation data)
2. 2010 with 20 percent renewables (based on RPS requirements)
3. 2020 with 33 percent renewables (based on RPS goal)
4. 2030 with 33 percent renewables (based on same portfolio as Scenario 3, with increased overall electricity generation to meet 2030 demands)
5. 2020 with a fossil fuel-focused approach
6. 2020 with a technology-focused approach (dry cooling and IGCC)
7. 2020 with a primary energy-focused approach (water-efficient, low-carbon, minimal land use)
8. 2020 with a primary energy AND technology-focused approach
9. 2020 with a technology focused approach, including coastal plants (on wet recirculating cooling)
10. 2020 with a technology focused approach, including coastal plants (on dry cooling)

The following section presents our projected water requirements for the current (2005) statewide portfolio and several future scenarios. Note that the water requirements projected under the current portfolio include both seawater and freshwater resources; all other scenarios only include freshwater resources.

Current Portfolio, 2005

The electricity generated in California during the year 2005 required a significant amount of water. Given that coastal facilities rely on seawater for once-through cooling, they withdraw over 100 times more water than facilities that rely on wet recirculating or dry cooling. Thus, seawater withdrawals dominate the state's total water withdrawals. Similarly, hydroelectric facilities withdraw and consume significantly more water than other freshwater facilities (Figure 54).

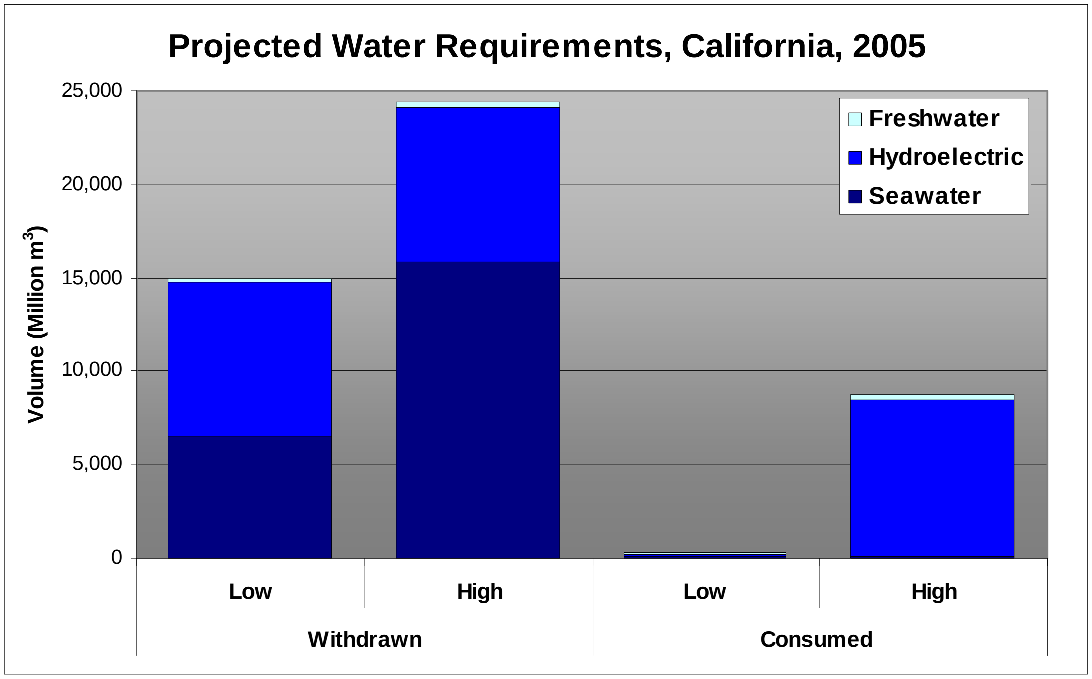

Figure 54. Projected water requirements for electricity generation in the State of California in 2005. These estimated withdrawals and consumption include freshwater (from surface and ground water sources), sea water, and freshwater in hydroelectric facilities.

Focusing on only the freshwater withdrawals and consumption, we estimate California's total annual water withdrawals at 140 to 290 million cubic meters, and total consumption at 135 to 260 million cubic meters. This figure includes water used for mining, transporting, and processing, some of which may not occur in California (e.g. most of the coal may be mined in the Southwestern U.S.). It does, however, represent California's total freshwater "footprint" (Figure 55).

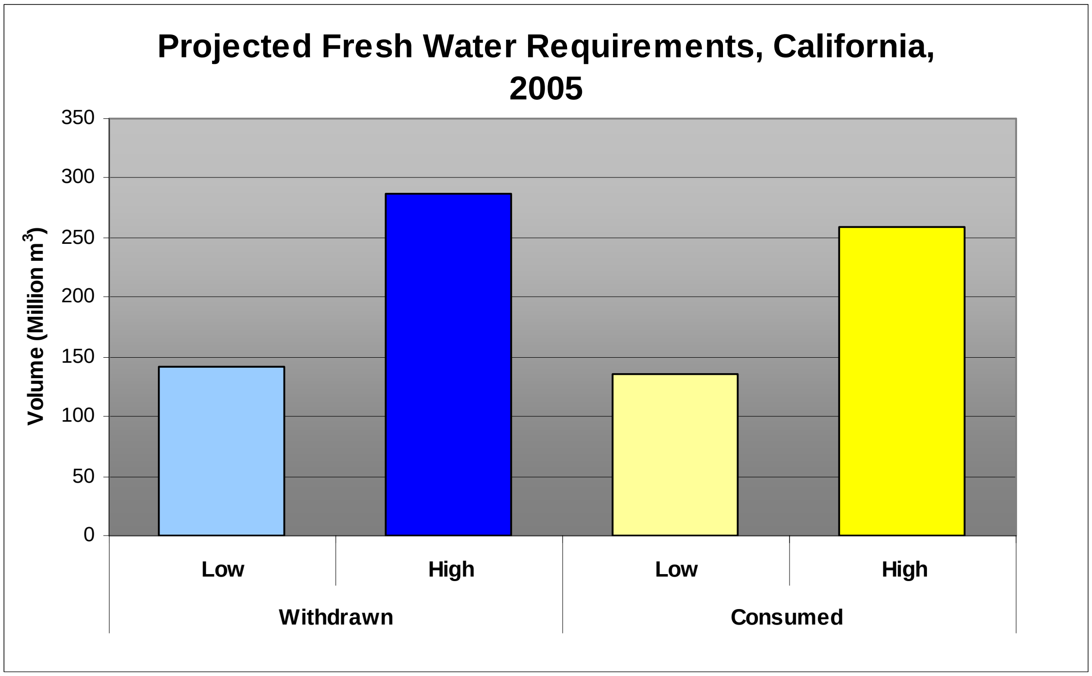

Figure 55. Projected water requirements for electricity generation in the State of California in 2005. These numbers only include withdrawals and consumption from freshwater sources. Note the different scales used in Figure 54 and Figure 55.

Future Scenarios

Using the CEC's projected growth rate of electricity demand, we estimate total electricity demand to be 8 percent greater in 2010, and 25 percent greater in 2020, relative to 2005 demand (California Energy Commission, 2003). Based on the projected RPS mix and other assumptions, we estimate the energy mixes shown in Figure 56 for 2010 and 2020.

The increased demand and energy portfolios presented above result in increased total freshwater withdrawals and consumption (Figure 57). Relative to estimated water withdrawal in 2005, future withdrawals increase by 3 percent (5.9 million cubic meters) in 2010, and 35 percent (75 million cubic meters) in 2020; estimated consumption of water increases by 4 percent (8.2 million cubic meters) in 2010, and 41 percent (80 million cubic meters) in 2020.

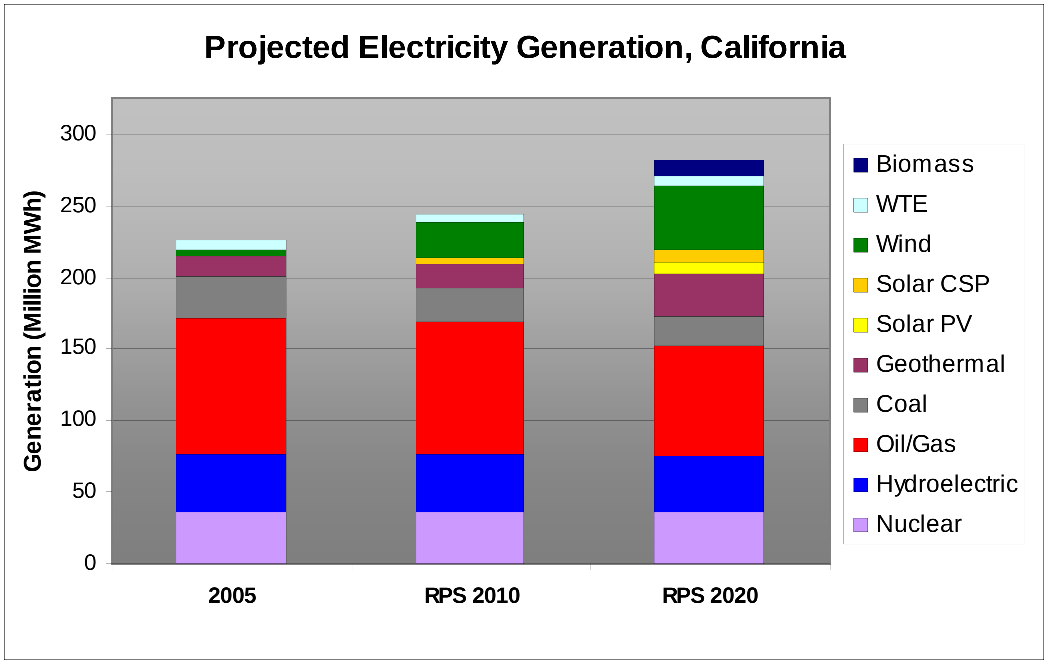

Figure 56. California's projected electricity generation in 2010 and 2020 under the estimated RPS mix, compared with electricity generation in 2005.

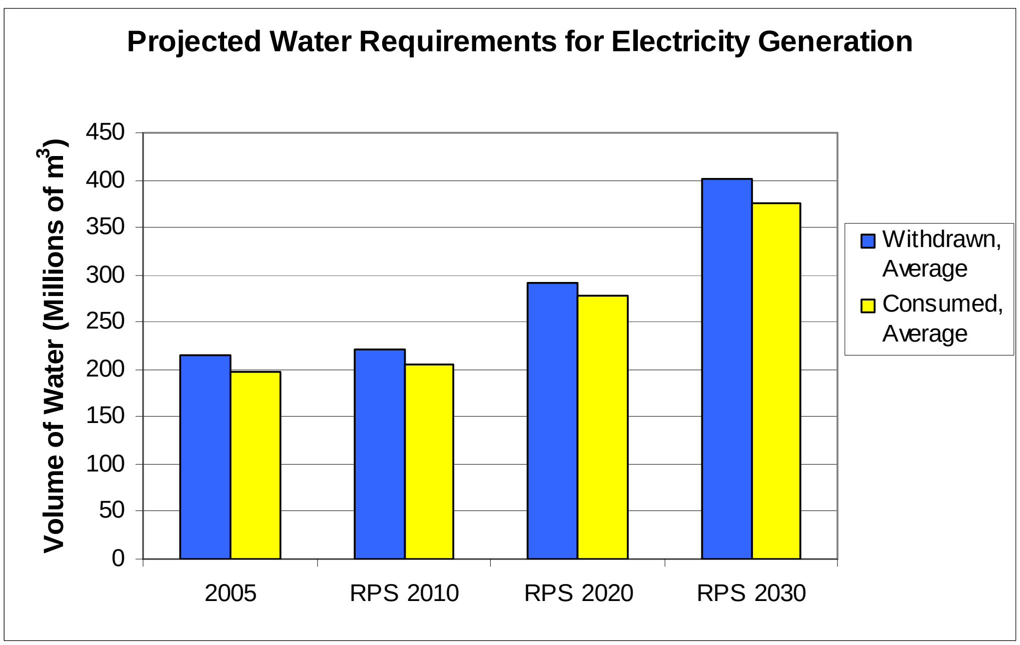

Figure 57. Water requirements for current and projected energy generation in 2010 and 2020, based on the estimated RPS. Water requirements in 2030 are based on the 2020 energy mix and 2030 demand. Estimates for withdrawn and consumed water are averages of our low and high projections.

Considering the increased water demands projected in 2010 RPS and 2020 RPS, we identified several contrasting energy portfolios that could alter the water impacts of electricity generation:

1. A fossil-fuel based portfolio (Scenario 5);
2. A portfolio that relies on the same mix of primary energy sources identified by the RPS, but improved technology (Scenario 6);
3. A portfolio that changes the energy mix in favor of water-efficient primary energy sources (Scenario 7); and
4. A portfolio that emphasizes water-efficient primary energy sources and conversion technologies (Scenario 8).

These four energy portfolios (Table 15); (Figure 58); (Figure 59); (Figure 60) require less water than the 2005 portfolio (Figure 61); (Table 16). Closer analysis of the breakdown of water use for each of the different energy sources illustrates the large impact of electricity generated from geothermal and coal sources (Figure 62). By installing more water-efficient technology (dry cooling and IGCC conversion of coal), California's projected annual freshwater withdrawal and consumption decreases by 68 percent (205 million cubic meters), relative to the RPS for 2020. By relying on more water efficient primary energy sources, we project that California's water withdrawals and consumption decrease by 93 percent (approximately 285 million cubic meters), relative to the RPS 2020. Incorporating *both* water efficient primary energy sources and conversion technologies reduces water requirements by slightly more: 95 percent (290 million cubic meters) less than projected for the 2020 RPS.

It is important to note that some scenarios, such as the fossil-fuel based portfolio (Scenario 5), will have other negative environmental impacts, such as greenhouse gas emissions, air and water pollution. The portfolio that relies on more modern, efficient technology (Scenario 6) may diminish both water and greenhouse gas emissions (relative to the projected RPS), but the altered energy portfolio (Scenario 7) offers much more dramatic reductions in both greenhouse gas emissions and water use, while minimizing land use impacts. These energy portfolios may not be feasible in 2020, due to the need to replace existing generation infrastructure. They do, however, illustrate the impact of relying on different primary energy sources and improved technologies. A similar analysis could be applied to electricity production in 2030 or 2050, perhaps more reasonable dates for broad energy portfolio restructuring.

Table 15. Energy mix for 2020 under three projected scenarios: the RPS, a fossil-fuel based portfolio, and a water-efficient mix of primary energy sources. The "Improved Technology" scenario relies on the projected RPS for 2020.

Projected Energy Mixes, 2020			
	Generation (MWh, millions)		
Energy Source	**RPS (Scenarios 3 and 6)**	**Fossil-Fuel Based Mix (Scenario 5)**	**Water-Efficient Primary Energy Based Mix (Scenarios 7 and 8)**
Nuclear	36.0	36.0	33.0
Hydroelectric	39.9	39.9	35.0
Oil/Gas	77.2	140	58.5
Coal	20.5	40.0	0
Geothermal	29.0	14.4	0
Solar PV	8.3	0	86.0
Solar CSP	8.3	0.7	0
Wind	45.0	4.1	45.0
WTE	7.0	6.0	11.5
Biomass	11.5	0	13.3
Total	282	282	282

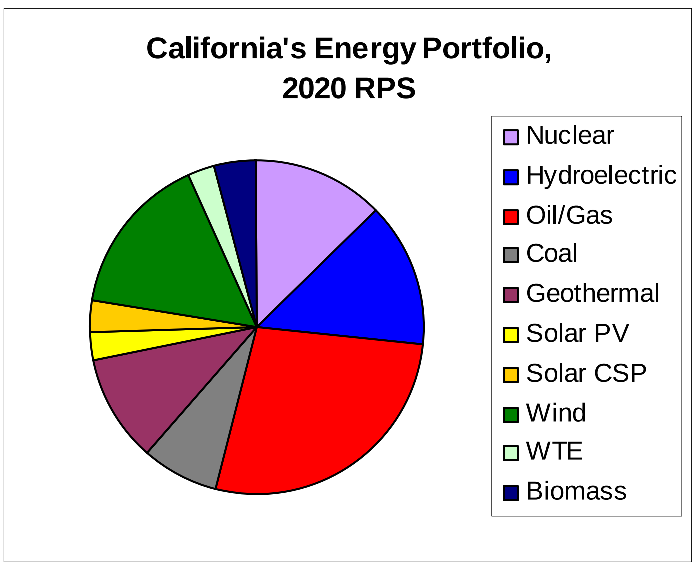

Figure 58. California's anticipated energy portfolio for 2020, based on projected demand and the mandated 33 percent RPS (Scenarios 3 and 6).

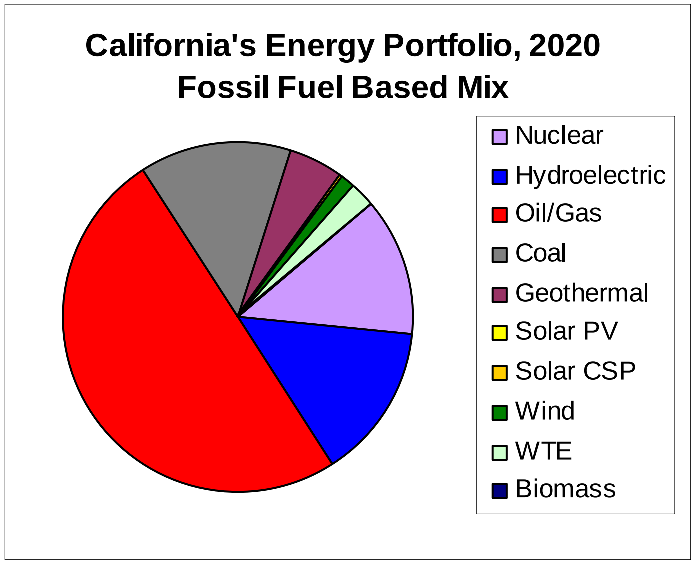

Figure 59. A possible energy portfolio for California based on projected demand for 2020, that relies heavily on fossil-fuel based energy sources (Scenario 5).

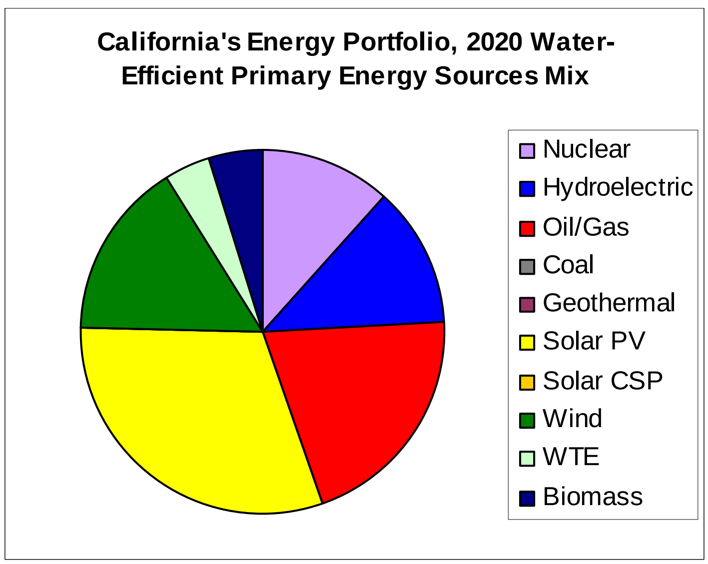

Figure 60. A possible energy portfolio for California based on projected demand for 2020, that relies heavily on water-efficient primary energy sources (Scenarios 7 and 8).

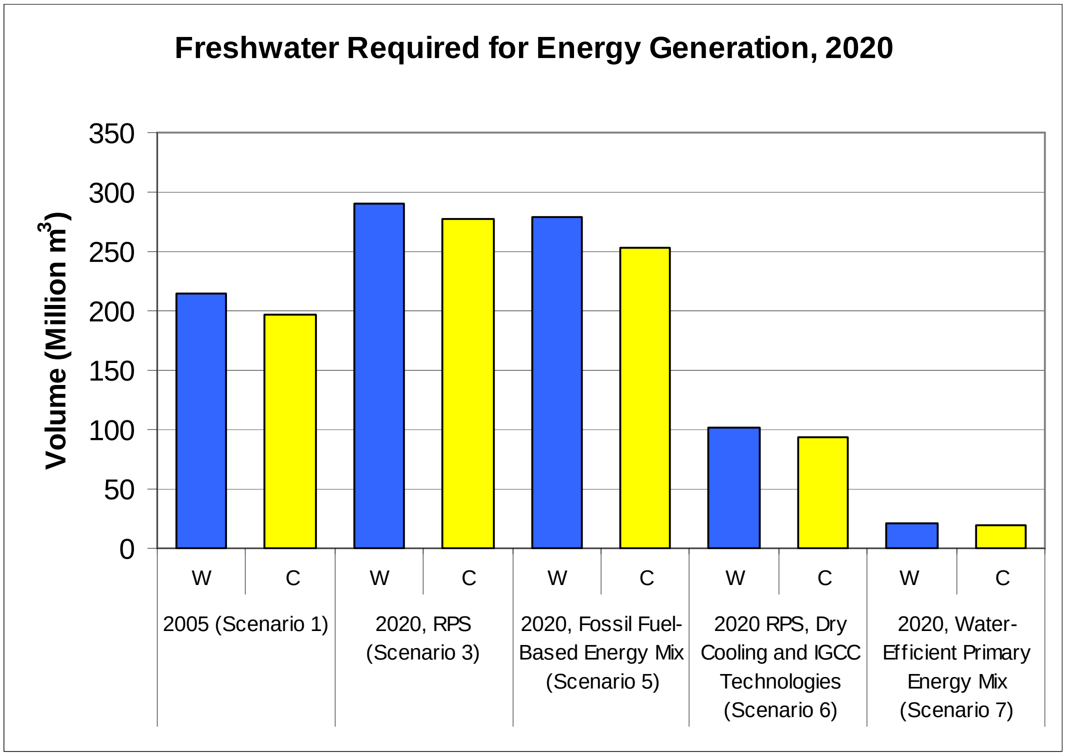

Figure 61. Water required for electricity generation in 2020, using several different energy portfolios. 2005 projections are included for comparison. Only average projections are represented. W and C stand for withdrawal and consumption, respectively.

Table 16. Water withdrawals and consumption for the 2005 energy portfolio and four future portfolios.

	Water Requirements (m^3, millions)			
	Withdrawal, Low	**Withdrawal, High**	**Consumption, Low**	**Consumption, High**
2005 (Scenario 1)	142	288	135	259
2020, RPS (Scenario 3)	187	392	182	372
2020, Fossil Fuel-Based Energy Mix (Scenario 5)	172	387	160	345
2020 RPS, Dry Cooling and IGCC Technologies (Scenario 6)	82	122	80	108
2020, Water-Efficient Primary Energy Mix (Scenario 7)	16	26	15	25
2020, Water-Efficient Primary Energy Mix and Conversion Technologies (Scenario 8)	10	19	9	19

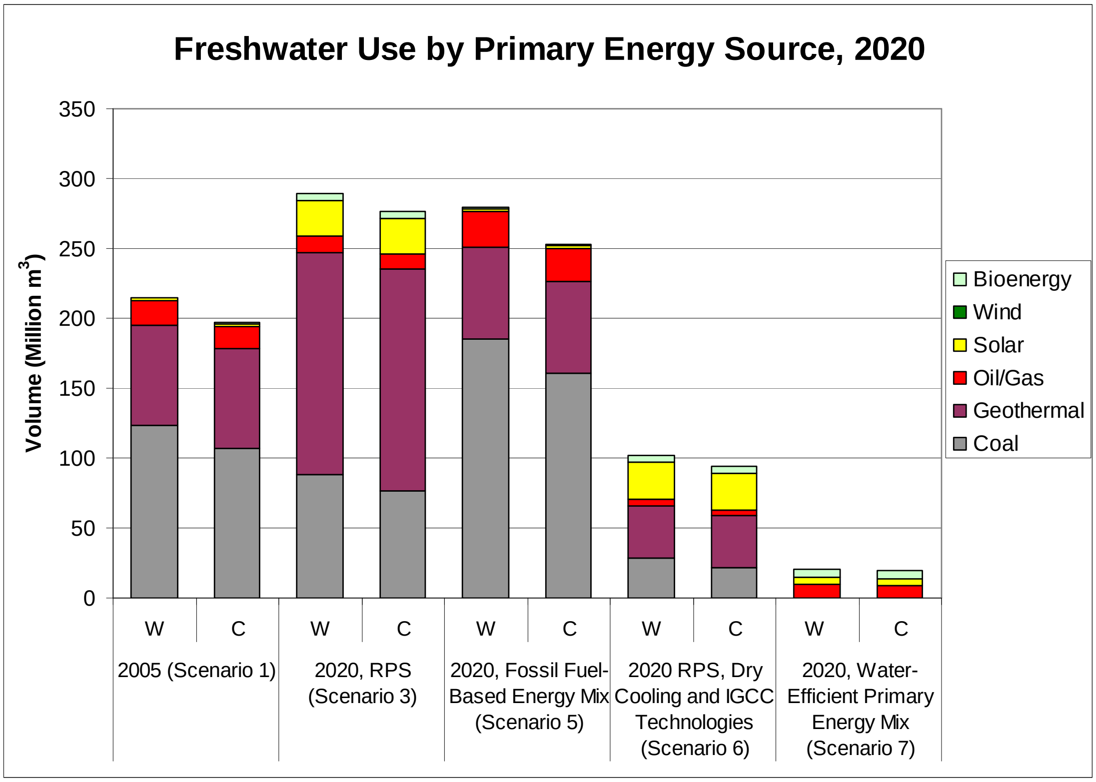

Figure 62. Average water required for electricity generation in 2005 and four future scenarios (2020). Water requirements are broken down by primary energy source. W and C stand for withdrawal and consumption, respectively. **Note:** Coastal facilities (all nuclear and some natural gas) and hydroelectric facilities are excluded.

Converting Seawater-Cooled Facilities to Freshwater

As noted earlier in this section, the scenario analyses for California focus only on freshwater resources. The use of seawater for once-through cooling in coastal power plants has significant impacts on the marine environment; however, converting coastal facilities onto freshwater resources *without* altering cooling technologies will require extremely large volumes of freshwater.

Converting these coastal natural gas facilities' cooling technologies to wet-recirculating or dry cooling increases the statewide demand for freshwater by a moderate amount. Relative to the statewide freshwater demand with efficient technologies[19] employed in all inland plants, converting coastal facilities to wet-recirculating cooling systems increases the statewide freshwater withdrawals by 36 percent (36 million cubic meters) and consumption by 30 percent (29 million cubic meters). In comparison, converting these coastal plants to dry cooling only increases

[19] Efficient technologies include dry cooling and IGCC conversion technologies.

freshwater withdrawals by 7 percent (7.4 million cubic meters) and consumption by 1.4 percent (1.3 million cubic meters). It is important to note that these projections are *less than* the volume withdrawn or consumed in 2005. We do not consider converting nuclear facilities to dry cooling, because the technology is currently unavailable or unproven. Nuclear facilities could utilize wet recirculating cooling technologies, but for clear comparison between scenarios, they are excluded.

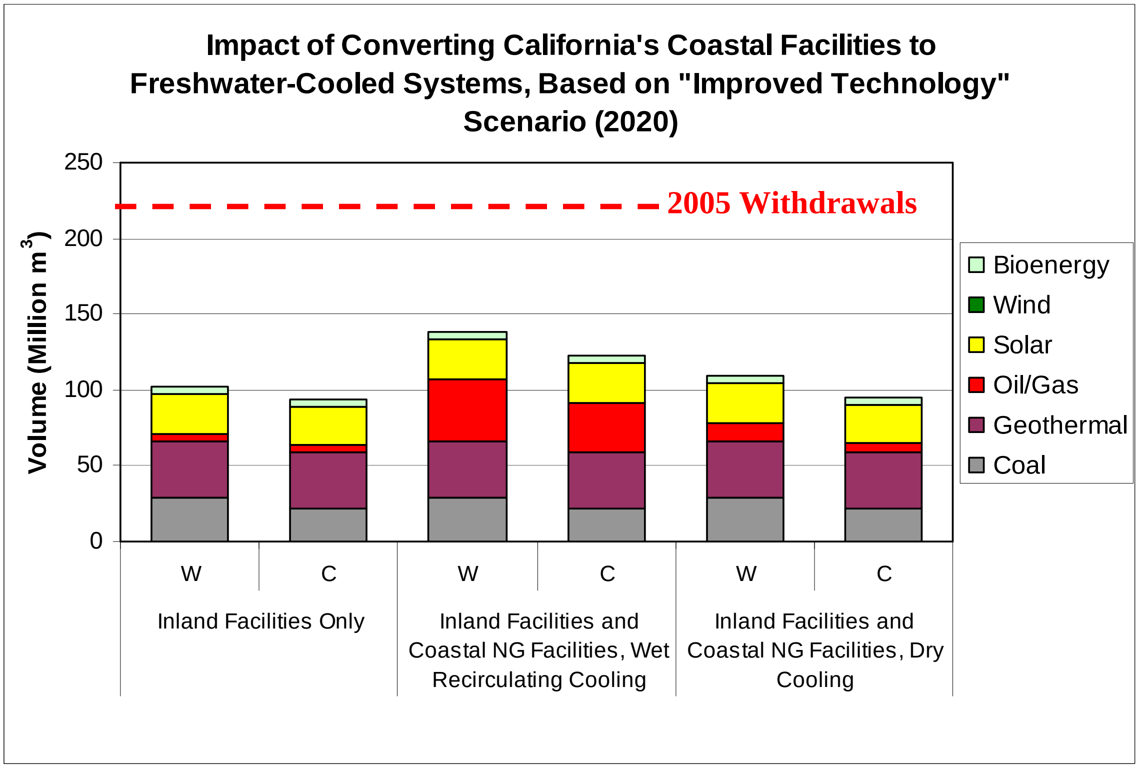

Figure 63. Impact of converting coastal facilities to freshwater-cooled systems. The energy mix for all scenarios is the projected 2020 RPS; all inland facilities rely on dry cooling and IGCC conversion technology. **Note**: Estimated freshwater withdrawals in 2005 are 215 million cubic meters. Nuclear facilities are not included (see text). W and C stand for withdrawal and consumption, respectively.

In conclusion, the water required to meet electricity demand in 2010, 2020, and 2030, based on projected energy mixes, increases progressively. Surprisingly, the projected water required under the fossil-fuel focused scenario is lower than that required by the RPS. Within the RPS based scenario for 2020, geothermal power accounts for a large amount of the water required. The implementation of water-efficient generation technologies or the conversion of generation to more water-efficient primary energy sources reduces a given portfolio's water requirements. Finally, converting coastal natural gas plants to freshwater-cooled systems can have moderate to negligible impacts on freshwater resources, depending on the cooling technologies employed.

Discussion

Our results show that water requirements for electricity generation vary greatly, depending on both the primary energy source and the conversion technologies employed. It is difficult to make generalizations about the water use for renewable and non-renewable sources of energy; renewable sources of energy like geothermal and biomass may require significant amounts of water, while other renewables such as solar photovoltaics and wind power typically require negligible amounts of water. Likewise, fossil fuel sources of energy can require large or small quantities of water, depending on the cooling technology employed. In addition, the conversion efficiency of a plant can impact the water requirements; a coal plant using combined cycle technologies captures more of the coal's latent energy than a simple cycle plant, decreasing the water required per unit of electricity generated.

Data Collection

Water efficient forms of electricity generation include both renewable and non-renewable primary energy sources. Renewable sources of electricity that require minimal volumes of water include solar photovoltaics, wind turbines, and certain forms of geothermal power. More specifically, these water-efficient sources include solar and wind facilities that do not wash their equipment (primarily in low dust environments), and geothermal resources that rely on geothermal fluid for cooling and resource recharge. Additionally, electricity generated from biogas may use negligible amounts of water, if the gas is captured from a landfill or animal wastes and converted to electricity in microturbines or simple cycle generators (0.08 m^3/MWh).

For non-renewable sources of energy, water requirements for cooling processes have the greatest influence on the overall water demands, while mining, transportation, and fuel conversion processes have less of an impact. Conversion of natural gas in a simple cycle plant requires the lowest volume of water of all forms of fossil-fuel based generation (withdrawals and consumption equal to 0.12 m^3/MWh). A combined cycle, dry cooled natural gas plant withdraws slightly more water (0.18m^3/MWh), but consumes significantly less water (0.032 m^3/MWh). Generating electricity from coal requires more water: surface-mined, unwashed coal in combination with fuel conversion in a dry-cooled, conventional pulverized combustion facility represents the most water-efficient coal based electricity (withdrawals of 0.51 m^3/MWh). Dry cooling, however, has several drawbacks. Although dry cooling can significantly reduce water withdrawals and consumption, it is associated with the disadvantages of additional capital costs, land use requirements, and energy penalties (Gleick, 1994).

Interestingly, the most water *intensive* sources of electricity can stem from the same primary energy sources that are the most water-efficient. Bioenergy, if produced from certain dedicated energy crops (as opposed to biogas produced from waste), has the highest rates of water withdrawal and consumption of all energy sources, at over 1,250 m^3/MWh. It is important to note that the estimates of water withdrawals and consumption represent rates of evapotranspiration; inefficient irrigation systems will lead to *much higher* rates of withdrawals. Certainly, rates of irrigation and evapotranspiration will vary, depending on the crop type and location; California may represent the more water intensive end of the spectrum for dedicated crop based energy generation. While the state currently only relies on waste-based bioenergy, California's Secretary of Agriculture has recently endorsed growing sugarcane in the arid Imperial Valley for bioenergy[20] (Kawamura, 2006), which will almost certainly require extraordinarily large amounts of water.

Thermoelectric power generation from both renewable and non-renewable resources requires notably large amounts of water for cooling, particularly when once-through systems are used. In California, these systems are primarily employed by large, coastal, seawater cooled natural gas and nuclear power plants, which withdraw up to 190 m^3/MWh and 228 m^3/MWh, respectively. In some places, once-through cooling has been used for geothermal plants, withdrawing up to 54 m^3/MWh in the case of Nesjavellir Plant in Iceland (Kagel et al., 2005). Converting these facilities to wet recirculating or dry cooling systems could reduce water withdrawals by two to three orders of magnitude (for wet and dry cooling, respectively). Converting systems to wet recirculating cooling *increases* rates of water consumption, however.

Because of their role in the projected RPS for California, understanding the cooling systems of geothermal facilities is vital. Although geothermal plants in the Imperial Valley use wet recirculating cooling systems, those cooling systems still require relatively high amounts of water, most of which is drawn from agricultural drainage canals and sources of brackish water (Layton, 1978). It is important to note that geothermal facilities may use water of lower quality; therefore, water needs for electricity generation do not necessarily compete directly with municipal or agricultural demands. As the Imperial Valley geothermal fields have the most extensive untapped resources, most of California's increases in geothermal power will likely come from this region. Another reason for the large water requirements of geothermal facilities is the water required for resource recharge; The Geysers pumps 3.5 m^3/MWh into its wells to maintain steam production levels for a longer period of years (Geothermal Research Council, 2003).

This analysis does not focus on the water withdrawn or consumed in hydroelectric facilities. In many cases, however, the amount of water evaporated from reservoir surfaces is not negligible, and should not be ignored. As indicated by our data, rates

[20] He did not specify whether the crops should be used for transportation fuels or electricity production.

of evaporation vary substantially, depending on the local climate and reservoir morphology. Generating electricity in hydropower facilities represents a substantial trade-off between power and water supplies.

Electricity generation does not necessarily require pristine water. In many cases, recycled or reclaimed water represents an adequate, if not preferable source of water, as it decreases the magnitude of freshwater withdrawals. Proximity to the plant and treated quality of recycled water also increases its likelihood of use in power plants. Often, the salt and mineral content in recycled or reclaimed water is comparable to that of freshwater, but typically, it is not a preferred source of drinking water. Reclaimed water does, however, serve as a very reliable water supply, an important criteria for the electricity generation sector. Reclaimed water can be used for cooling in thermoelectric facilities, recharging geothermal resources, and washing solar panels and wind turbines. It may also be used for growing dedicated energy crops, but supplying an adequate volume may prove impractical or energy-intensive (if the water is pumped). Clearly, co-location of power plants and wastewater treatment facilities makes reclaimed water a more attractive option.

The data cited throughout this analysis has been collected from numerous and varied sources; it is, however, limited in several respects. In several cases, the availability of data was limited: only one statistic on the water required for uranium mining was available, and all information on water use in wind power comes from industry sources. Similarly, information on the water requirements for geothermal resources and growing dedicated energy crops was scarce, and infrequently-used technologies, such as oil shale mining, have little published water use data. In cases where numerous sources provided statistics, we adopted the lowest and highest figures, which may stem from two different sources. Finally, the data incorporates numerous assumptions, which range from conversion efficiencies (e.g., from a barrel of crude oil to MWh) to average capacity factors (e.g., for wind turbines). All assumptions are based on reputable sources, and are clearly noted in the workbook and in Appendix B.

Verification

Verification served as a useful approach for gauging the accuracy of our collected data. Comparing our projected annual water withdrawals with USGS estimates provided mixed results. Our projections compare well with the USGS estimates for the coastal counties in California, but severely overestimate water withdrawals for an inland county, San Bernardino. Several factors may be responsible, including both broad compounding issues with the USGS estimates, and local or regional factors.

The USGS estimates reflect thermoelectric water withdrawals from both fresh and seawater, reported on a county by county basis. The data represents voluntary responses from thermoelectric facilities; the USGS reports a 35 percent response rate (Haltom, 2006). They extrapolated from these responses to estimate county-wide and state-wide averages. Several potential sources of error are apparent: the voluntarily-reported data are not verified by a third party, and may be skewed (either intentionally or unintentionally) and the 35 percent of reporting facilities may not represent all power plants in a county, invalidating the extrapolation. Finally, in California, data was only available for seven counties; this underscores the lack of comprehensive, reliable data on the water required for electricity generation today.

For the three coastal counties, Monterey, San Diego, and San Luis Obispo, the USGS estimates of thermoelectric withdrawals fall within our projected ranges. In these counties, once-through cooling dominates total water withdrawals, marginalizing all mining, transportation, or processing withdrawals. Using an accurate figure for once-through cooling withdrawals, therefore, is essential. Estimates for once-through cooling withdrawals range from 75 to 227 m^3/MWh, resulting in a wide range of total estimates for water withdrawals.

Our projected annual water withdrawals in San Bernardino County are over six to nine times higher than those estimated by the USGS. Several factors may explain this discrepancy. Most notably, the USGS's estimates reflect water withdrawn from surface and ground water sources, but do not include reclaimed or recycled water; one of the major natural gas facilities in San Bernardino County relies on reclaimed water for cooling. Secondly, our estimates rely on several key assumptions, including a projected breakdown of natural gas plants into baseload plants and "peakers", an average capacity factor for each of these types of facilities, and the predominant cooling technology employed in all electricity generation stations. Each of these assumptions introduces possible sources of error. Finally, our estimates reflect the total water required for electricity generation, including mining, transportation, and processing needs. The USGS data, however, only reflects thermoelectric cooling withdrawals. (As an additional note, some of these water needs may occur outside of the county.)

Overall, our collected data compares reasonably well with USGS projections of water withdrawals for three of the four counties examined. Based on these results, and our understanding of why our projections differ from those of the USGS in San Bernardino County, we felt confident in estimating water requirements for future statewide electricity demands.

Scenarios

The scenarios presented clearly illuminate the impacts of differing energy portfolios on water resources. The scenarios do not necessarily reflect California's *likely* energy portfolio in 2020, but provide a guide as to how current planning decisions in the energy sector may affect future water needs.

Evaluation of the current and future projected water requirements yields a few surprises. As electricity demand grows, the water required to produce it will also increase. Future water requirements under the projected RPS for 2020 (Figure 57), however, are somewhat astonishing – we project freshwater withdrawals to increase (on average) by 35 percent, or 75 million cubic meters, relative to 2005 withdrawals. This figure represents an *average* projection; the high estimate of water withdrawals is almost 177 million cubic meters larger, representing an increase of 83 percent more water than withdrawn in 2005.

Comparing the projected water needs for the RPS energy mix in 2020 with the needs of several alternate scenarios also reveals several surprises. In particular, the projected RPS for 2020 does not offer any water benefits over a fossil-fuel based energy mix. This is mainly due to the sizable percentage of geothermal power in the 2020 RPS. Our analysis excluded the withdrawal of geothermal fluids, because it is notably different from freshwater sources, and because it is not used in municipal or agricultural applications. A scenario employing the RPS-derived energy mix, and improved conversion and cooling technologies in coal, natural gas, and geothermal facilities, offers significant water savings, reducing projected withdrawals and consumption by approximately 68 percent. Changing the energy portfolio offers more dramatic water savings, reducing projected withdrawals and consumption by 90 percent (Figure 57). Employing both water efficient energy sources and conversion technologies offers slightly greater benefits, reducing projected withdrawals and consumption by 95 percent, relative to the 2020 RPS.

Clearly, cooling technologies and primary energy sources can result in highly varying water requirements. Future electricity generation plans, therefore, can be designed to minimize water use by adapting cooling technologies or by selecting certain primary energy sources over others. The scenarios in our analysis illustrate the impacts of different energy mixes on the water resources of California. Other factors may influence these projections; further improvements in cooling technologies that minimize energy penalties may increase the implementation of dry cooling, and improvements in solar and wind power's ability to capture energy may increase their roles. Conversely, increased investment in dedicated energy crops may result in exponentially greater water requirements. All of our scenario analyses explicitly excluded dedicated energy crops, as most current sources of bioenergy stem from waste products.

Finally, the high rates of seawater withdrawals for once-through cooling of coastal plants can have significant impacts on marine ecosystems. In the future, coastal power plants will likely rely on freshwater resources for cooling. As older plants are relicensed or re-commissioned, they too will likely have to convert to freshwater cooling, which will require conversion to wet-recirculating or dry cooling technologies. While converting existing coastal natural gas facilities increases the total amount of water required for electricity generation in California, it is not unfeasible. If more efficient conversion and cooling technologies are implemented in facilities throughout the state, *including* coastal facilities, the electricity sector can meet 2020 demand *and* use less water than projected for 2005.

Web-based Tool

The link to the web-based tool and supporting documents can be found on this project's website: http://www.bren.ucsb.edu/~energywater.

The web-based tool is flexible, allowing users to input an unlimited number of energy sources. This makes it very useful to both small and large energy utilities for integrated water and energy planning. Furthermore, users can add and alter existing lines without re-entering prior data entries. This feature makes it easy to manipulate a given electricity generation portfolio and examine how increased investment in different generation technologies and primary energy sources can affect overall water use.

The web-based tool reflects the best estimates that our research of the literature, government sources, and the energy community provided. The tool's output is, however, an estimate. The ranges calculated by the tool are meant to allow a knowledgeable user to speculate, based on the operational conditions of each of their facilities, what the water requirements of their portfolio might be. Every facility will operate differently, even if the same primary energy source and conversion technologies are used.

Other Factors

There are many other factors, limitations, and considerations in examining solutions and policies regarding issues connected to the energy-water nexus. Economic considerations related to the cost of electricity are important. Capital costs vary widely across the various primary energy sources and technologies. Additionally, there are many laws and policies already enacted that shape energy and water development and electricity generation. Further issues include siting and land use limitations; the need for reliable baseload generation; and the possible impacts of long-term drought.

Each of these other factors could, in themselves, be separate analyses. While our analysis was limited in scope and could not address all the related factors, a brief summary of the major issues are discussed in the following section.

Economic Considerations

Costs vary for each type of electricity generation technology. Some of the factors affecting the cost of generation are as follows (Gruenspecht, 2005):

- Licensing
- Permitting
- Construction (and length of time to build)
- Financing
- Fuel cost
- Operation
- Maintenance
- Decommissioning

The scale of each of these factors varies considerably with each technology. For example, the expense of natural gas plants mainly comes from fuel costs, whereas the expense of coal plants is mainly due to construction costs, as coal is a cheaper fuel. Nuclear plants take a long time to build, and also have high operation and maintenance costs. Renewable technologies generally feature high construction costs as well, although the fuel cost may be as low as zero (Gruenspecht, 2005).

To address this problem of different costs accruing during different stages of the electricity generation process, the concept of levelized cost is used. Levelized cost incorporates all of the variables that contribute to the cost of energy generation, and is defined as "the average cost of power production over the life of a power plant, taking into account all capital expenses and operating and maintenance costs, as well as fuel costs for power plants that rely on external fuel sources" (Shibaki, 2003). This cost is adjusted for inflation (USDOE - EIA). Table 17 shows the range of levelized costs for various technologies.

Table 17. Levelized cost ranges of various energy generation technologies, shown for general comparison purposes. Lifetime of the plant considered was either 20 or 30 years. Figures are 2003-2005 monetary values, unadjusted for 2007. It is assumed that not adjusting for 2007 will not significantly affect the numbers (Gruenspecht, 2005); (Shibaki, 2003); (Badr & Benjamin, 2003); (Spitzley & Keoleian, 2004).

Technology	Economic Lifetime (years)	Levelized Cost Range (cents/kWh)
Hydropower	30	0.5-13.0
Nuclear	20	1.5-6.0
Geothermal	30	1.5-7.64
Coal	20	2.0-8.0
Natural Gas		
Combined cycle	20	3.0-7.0
Simple cycle	20	~14.06
Wind	30	4.8-13.0
Biomass	20	5.0-8.0
Solar Thermal		
CSP Parabolic Trough	30	7.0-21.53
CSP Stirling Dish	30	14-30
Photovoltaic	30	30-80
Fuel Cells	20	9.10-20.89

The ranges of levelized costs often overlap between the various technologies. By breaking down the levelized cost and exploring only one variable at a time, however, the comparative economic advantages between various technologies can be seen more clearly.

One of these variables is capital cost. Capital cost includes building construction (materials and length), land prices, and equipment construction (Shibaki, 2003); (Gruenspecht, 2005). When taking into account only capital costs, natural gas plants have the advantage (Table 18). The low capital cost of natural gas plants helps offset the high cost of natural gas as a fuel.

Table 18. Capital costs of various technologies (World Bank, 2005).

Technology	Capital Cost ($ per kW)
Gas turbine – central	350 - 450
Diesel engine - distributed	400 - 500
Gas combined cycle	400 - 600
Gas turbine – distributed	700 - 800
Conventional coal	800 – 1,300
Wind – onshore	900 – 1,100
Advanced coal	1,100 – 1,300
Coal gasification (IGCC)	1,300 – 1,600
Wind – offshore	1,500 – 1,600
Bioenergy	1,500 – 2,500
Nuclear	1,700 – 2,150
Geothermal	1,800 – 2,600
Hydropower	1,900 – 2,600
Fuel cell – distributed	3,000 – 4,000
Photovoltaic – central	4,000 – 5,000
Photovoltaic - distributed	6,000 – 7,000

When only production costs (cost of facility purchase and operation) are considered, renewable technologies are the cheapest, which stands in stark contrast to the high capital cost of renewable technologies. Coal is significantly cheaper than gas and oil in this regard (Table 19).

Table 19. Production costs for energy sources (NEI, 2007a).

Production Costs in Cents/kWh	
Wind	0.04
Hydroelectric	0.83
Nuclear	1.72
Solar	2.17
Coal	2.21
Natural Gas	7.51
Petroleum	8.09

The economic future of renewable electricity generation is optimistic. Levelized costs of renewable technologies are projected to decrease in the future (Figure 64).

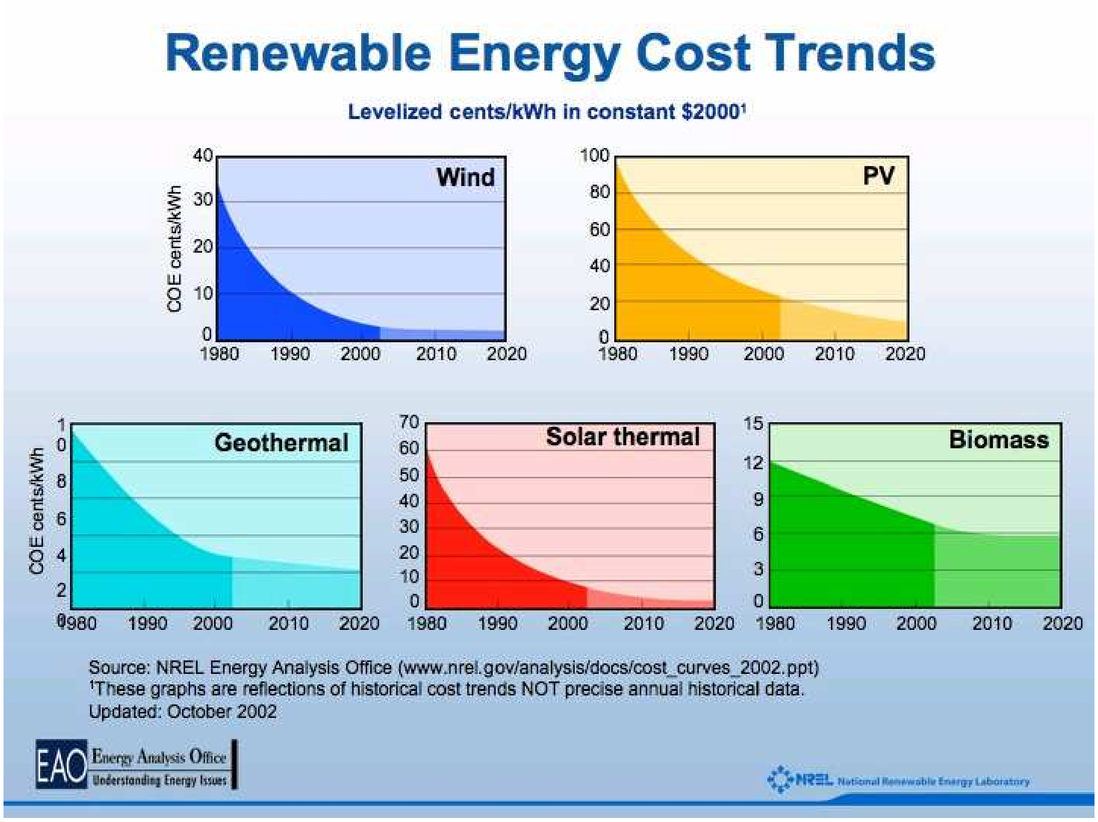

Figure 64. Renewable energy cost trends from 1980-2020 (NREL, 2005).

Economic considerations

The following is a discussion of economic considerations more specific to each technology.

Fossil Fuels

Coal is cheap and plentiful in the U.S., and it is one of the least expensive ways to produce power. The costs associated with coal generally are negative externalities, many of which are comparable to those of oil and natural gas. See the subsections entitled Environmental Impacts, under each section of the Background, for more information on these externalities.

The costs of coal, oil, and natural gas for electricity production have increased from 1994 to 2005. The sharpest increases were found in oil and natural gas (Table 20).

Table 20. Average cost of fossil fuels for the electric power industry, 1994-2005. Table has been modified and simplified from the original version (USDOE - EIA, 2006c).

Year	Coal		Petroleum		Natural Gas
	Average Cost		Average Cost		Average Cost
	(cents/million Btu)	(dollars/ton)	(cents/million Btu)	(dollars/ barrel)	(cents/million Btu)
1994	136	28.03	242	15.19	223
1995	132	27.01	257	16.10	198
1996	129	26.45	303	18.98	264
1997	127	26.16	273	17.18	276
1998	125	25.64	202	12.71	238
1999	122	24.72	236	14.81	257
2000	120	24.28	418	26.30	430
2001	123	24.68	369	23.20	449
2002	125	25.52	334	20.77	356
2003	128	26.00	433	26.78	539
2004	136	27.42	429	26.56	596
2005	154	31.20	644	39.65	821

In general, crude oil and natural gas prices have sharply increased in recent years, as shown by Figure 65 and Figure 66.

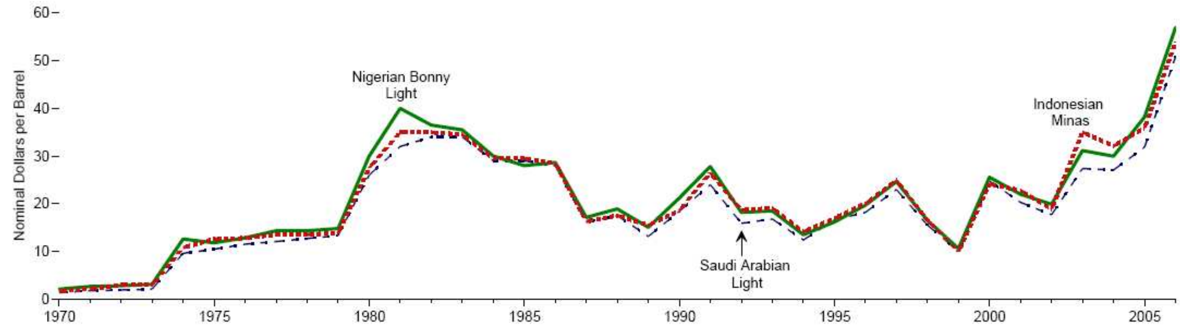

Figure 65. Crude oil prices by selected type, 1970-2005 (USDOE - EIA, 2006c).

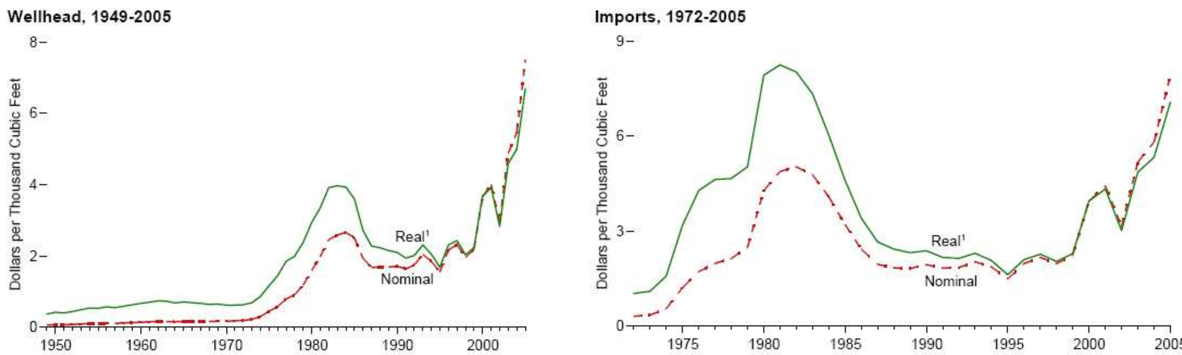

Figure 66. Natural gas wellhead and import prices (USDOE - EIA, 2006c). **Note:** Because horizontal and vertical scales differ, these two graphs should not be compared side-by-side.

Mining and generating energy from oil shale deposits is an expensive process; however, the high oil prices of the late 1970s and early 2000s (Figure 65 and Figure 66) have made it more economically attractive in the U.S.

Nuclear Power

Nuclear reactors and power plants are extremely costly to build. The technology and land required for a nuclear power plant make initial costs quite high. Nuclear plants built since the 1980s have cost $2 to $6 billion to construct (American Society of Civil Engineers, 2006). Operating costs also contribute to the overall cost of nuclear power: while relatively little fuel is needed, the maintenance and security costs are substantial factors. Additionally, disposal of spent nuclear fuel adds to the overall plant operation costs as well as overall decommissioning and the shutting down of a reactor, which are both long-term expensive costs. Unlike natural gas, however, uranium has relatively stable costs, making fuel costs steady and predictable.

Nuclear power plants, however, are large, reliable sources of electricity, with an average capacity over 950 MW in the U.S. (NRC, 2006b). Also, any new nuclear plants are likely to be even larger; new designs approved by the NRC are for 1,300

MW plants (NEI, 2007a). The general reliability and size make nuclear power ideal to meet baseload demands for almost any area.

Hydroelectric Power

Estimating the cost of hydroelectric power is challenging, and varies significantly, depending on the type and size of the facility. While the direct, operational costs may be low, the cost rises steeply when the costs of construction and decommissioning are also considered. In the case of hydroelectric dams, costs also depend on the political climate surrounding dams (e.g. extent of permitting required). These costs occur in three main phases: the initial (often substantial) capital investment for siting, licensing, and construction; maintenance and operational costs during the designed lifespan of the dam; and decommissioning, which, in some cases, involves dismantling the dam. Costs incurred in the latter two phases may also vary considerably, depending on rates of sedimentation and erosion, the environmental impact of the dam, and required mitigation (e.g. installing fish migration facilities).

Smaller facilities may incur fewer challenges with siting and permitting, but still have relatively high capital costs. In addition, these facilities are likely going to be constructed (and paid for) by private owners or irrigation districts; these entities would be taking a risk on the energy market (and future energy prices), unless they consume all electricity on-site (California Energy Commission and PIER, 2006).

Renewable Energy

Solar power

Photovoltaic systems

Overall, costs for large scale systems have been decreasing over the years, with those in the last few years being installed for only 0.55 cents/kW (Solar Electric Power Association, 2001). The cost of PV has fallen by 90 percent since the early 1970s at a rate of about 5 percent a year (Solar Electric Power Association, 2007). The operating costs of PV systems are low in comparison to other generation technologies as they require little maintenance and few staff; the capital costs make up the greatest portion of associated costs. With PV technology improving and the world’s energy demands increasing, PV will likely become both more cost efficient and necessary.

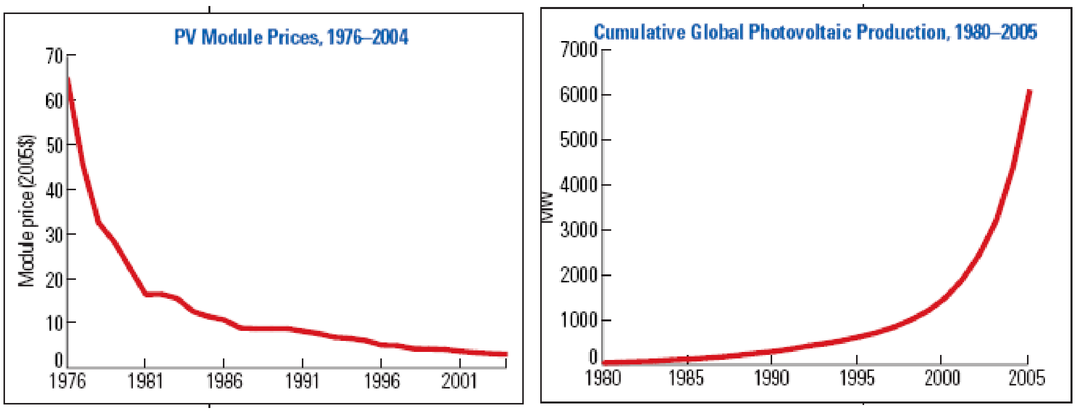

Figure 67. PV module costs and production, 1976 -2004 (Sawin et al., 2006).

One example of the cost effectiveness of PV technology is its growing use by utilities to meet new electricity demands. In some places it is less costly to install solar panels than to upgrade transmission and distribution systems. In 1995, the Union of Concerned Scientists conducted an in-depth evaluation of Boston Edison's distribution system and found "that PV could provide cost-effective power to 400,000 homes in Boston by 2013. By investing in solar electric power instead of wires and transformers, Boston-area ratepayers could save $50 million over the next 20 years" (Union of Concerned Scientists, 2006).

Photovoltaic solar technologies offer a much cleaner, accessible solution to the growing need for power. While more costly than fossil fuel based power, government subsidies and tax credits can be used to encourage private homeowners, large businesses, and utilities to make the switch to solar power. The encouragement these policies will also speed the implementation of the infrastructure necessary to lower the price of this technology in the long term, allowing the subsidies and credits to later be phased out. Also, increasing the interest and use of solar PV for power generation will motivate improvements in the technology, increasing its efficiency and contributing to lower prices.

<u>Concentrating Solar Power</u>

Because trough and power tower systems collect heat to run central turbine generators, they are better suited to large scale power plant applications. These larger systems also have a cost advantage of economy of scale. Cost per kW decreases as the plant size increases (Stoddard et al., 2006). The Energy Policy Act of 2005 contained a number of incentives for renewable energy generation. Specifically, the Act increased the Investment Tax Credit (ITC) to 30 percent through December 31, 2007, for solar facilities. After this date, solar facilities will still retain the "permanent" ITC of 10 percent, essentially a tax savings granted for solar investment that will remain in place long term, that existed before the Act was passed (Stoddard et al., 2006).

The ability to store electricity also increases a plant's ability to generate revenue. This is because the stored power, generated during periods of direct sunlight, can be sold during periods of high demand at higher profits. In general, CSP technologies do produce power during peak demand periods, which often occur during daylight hours. These increased revenues can help offset the cost of the storage system. Moreover, firm electricity (electricity that a plant can guarantee will be available when it is needed) is more valuable than unreliable electricity (for example, electricity that is periodically available due to power plant maintenance or a lack of sunlight) so a plant's ability to consistently provide electricity can increase revenues even further.

There are capital costs to consider in the installation of CSP plants; land, technical components, and construction costs all are factors in economic feasibility. For example, only sites with less than 1 percent slope and adequate DNI are eligible for installation (Stoddard et al., 2006); (Simons & McCabe, 2005). Furthermore, these technologies are still relatively new or emerging, meaning that technology purchase costs may, for the moment, be higher and the availability (especially of replacement parts) may not meet market demand.

Wind

Electricity from wind power varies in cost. Capital costs start with the site of the wind farm. Land for wind farms is typically in rural areas, keeping land costs somewhat minimal. A significantly larger amount of land, however, is needed, compared to fossil fuel-based electricity generation technologies. Additional costs come from the construction and placement costs of wind farms. This can be relatively quick and easy, compared to the construction of a traditional electricity generating plant; this is especially true compared to the Palo Verde nuclear plant, which took twelve years to build (USDOE - EIA, 2007b).

Depending on the location of the wind farm, additional infrastructure, such as transmission lines and roads may be necessary, contributing additional costs. Wind farms, however, are modular, thus enabling easier and in all likelihood, more cost-efficient capacity additions (additional wind turbines) as no new large structures or infrastructure is needed. Operation and maintenance needs constitute additional costs, though wind power has no associated fuel costs. Therefore, generating costs are not subject to market volatility and stay relatively constant.

Table 21 shows that the capital costs of a wind farm decrease as the size of the farm increases, due to economies of scale.

Table 21. Capital or up-front costs of various sized wind systems and typical payback (Union of Concerned Scientists, 2005c).

Costs and payback of typical wind turbines			
System Size kW	Capital or up-front cost	Annual energy production MWh	Payback using all farm power needs
10	$32,000	20-28	18-27 years
50	$130,000	100-150	12-18 years
225	$325,000	425-600	9-13 years
660-750	$800,000-$900,000	1,500-2,300	6-8 years

Bioenergy

Bioenergy has not been widely adopted because of its high cost of production relative to traditional, fossil fuel-based sources. In particular, energy derived from dedicated crops costs significantly more than energy from fossil fuels. Walsch et al. (1996) estimate the costs for producing and delivering energy using short rotation woody crops (such as shrub willows) at $0.72 – $0.83 per MWh; for comparison, large-scale coal power producers face costs of approximately $0.39 – $0.53 per MWh (Keoleian & Volk, 2005). In addition to production and delivery costs, some sources of bioenergy such as switchgrass may require additional processing in order to be viable. These additional processing steps (such as pelletizing or pulverizing) may further increase the cost of bioenergy by approximately 30 percent, to $1.28 - $1.36 per MWh. In order for switchgrass-based energy generation to compete with coal, the price of coal would have to increase to approximately $85/Mg (Cundiff & Shapouri, 1997).

The costs outlined above include the cost of production and transportation. These costs are irrelevant if the biomass feedstock is a waste product, or if energy is generated onsite, as is often the case. In this case, capital costs may represent a more significant economic barrier than processing or transportation costs.

In the case of landfill gas to energy facilities, the costs and patterns of electricity generation in California mimic those of the U.S. as a whole. In California, reciprocating engines are the most affordable technology for facilities smaller than 10 MW. Including capital and operating expenses for both the gas collection and electricity generation facilities, the cost of electricity from these plants ranges from $606,000 to $6,811,000 per MW, with an average cost of $1,993,000 per MW. The average cost of gas capture and electricity generation from all types of landfill gas energy plants in California is greater, at $3,500,000 per MW (Simons et al., 2002).

Geothermal

Although geothermal power is generated by way of heated underground water that is free of cost, geothermal power has higher construction costs compared to those of fossil power plants (Shibaki, 2003).

Capital Costs

Geothermal capital costs, which range from $1800-2600 per kW, include land values, drilling of wells to explore the source and pump the fluid, and the cost of construction. The drilling alone can make up to half of the capital cost. Geothermal drilling is more expensive and difficult than oil drilling due to the corrosive, tough properties of the fluid and rock. Wells cost $1 to $4 million to drill, and a geothermal field can consist of ten to one hundred wells (World Bank, 2005); (Shibaki, 2003).

Operations and Maintenance Costs

Operating and maintenance costs range from $0.015 to $0.045 per kWh, depending on how often the plant runs, which usually ranges from 90 to 98 percent of the time. Table 22 lists geothermal operating and maintenance costs by plant size. Larger plants tend to be cheaper to run and maintain due to economies of scale (Shibaki, 2003). The operating costs of geothermal plants are comparable to those of hydroelectric and fossil power plants (Table 23).

Table 22. Geothermal operating and maintenance costs by plant size, in cents/kWh (Shibaki, 2003).

Cost Component	Small Plants (< 5 MW)	Medium Plants (5–30 MW)	Large Plants (> 30 MW)
Steam field	0.35–0.7	0.25–0.35	0.15–0.25
Power plants	0.45–0.7	0.35–0.45	0.25–0.45
Total	0.8–1.4	0.6–0.8	0.4–0.7

Table 23. Operating and maintenance cost comparison by baseload power source, in cents/kWh (Shibaki, 2003).

Resource	Operating and Maintenance Cost (cents/kWh)
Geothermal	0.4–1.4
Hydropower	0.7
Coal	0.46
Nuclear	1.9

Overview of legislation affecting energy in California

General Energy Policies

Renewable Portfolio Standard (RPS)

In 2002, Governor Gray Davis signed the Renewable Portfolio Standard (RPS), which requires an annual increase of 1 percent in sales of renewable generation until the goal of 20 percent is reached in 2017. This goal was moved forward to 2010 by the adoption of the Energy Action Plan (EAP) by the California Energy Commission, the Public Utilities Commission (CPUC), and the Consumer Power and Conservation Financing Authority (California Energy Commission, 2005b).

Public Utility Regulatory Policies Act of 1978 (PURPA)

PURPA was passed in response to the energy crisis of the 1970s, to encourage more energy-efficient and environmentally friendly commercial energy production by defining qualifying facilities (QFs). QFs are small producers of energy that usually generate only for their own needs (but may have occasional extra energy), or incidental producers that generate electricity as a byproduct of other operations. If a QF meets the Federal Energy Regulatory Commission's requirements for ownership, size and efficiency, then utility companies, under PURPA, must buy from these facilities at rates that are lower than the cost to generate the electricity themselves (Energyvortex.com); (Union of Concerned Scientists, 2005b).

PURPA has been credited with bringing on line over 12,000 MW of non-hydro renewable generation capacity. PURPA has also brought about an increase in natural gas cogeneration facilities, as they produce steam heat along with electricity. Critics, however, believe that PURPA has not been updated to reflect declining prices of electricity from natural gas, as many QFs signed contracts in the 1980s under PURPA. They believe that as a result, PURPA does not promote renewable electricity generation to the maximum extent possible, especially as renewable electricity generation is expensive, and as air quality benefits are not considered under PURPA (Union of Concerned Scientists, 2005b).

Thermoelectric Power Generation Water Use Policies

The Clean Water Act (CWA)

The Clean Water Act is the flagship federal law regulating water pollution in the United States. It does this by setting standards on “point source” pollution discharges, which the states in turn enforce and implement. The CWA was amended in 1987 to include "non-point source" discharges, such as stormwater runoff from industries. The CWA also includes a permitting system. A few sections of the CWA are highly relevant to power generation, as cooling water outflows from power plants can cause major issues to waters in the nation.

CWA § 303 Water Quality Standards and Implementation Plans

This section of the CWA is also known as the Total Maximum Daily Load (TMDL) program. Section 303 requires states to develop lists of "impaired waters," or waters that fail to meet water quality standards (WQS) that the states have set, even after implementing pollution controls to attempt to comply with the CWA. These waters are then subjected to TMDLs, which specify the new maximum level of a pollutant that an impaired water body can have. The TMDLs, however, are still subject to approval from the federal EPA. After approval, states have ten years to develop plans for improving the pollution levels of the impaired waters (Feeley, 2006).

CWA §316(a) Water Thermal Discharge

Section 316(a) of the CWA requires regulation of the water coming out of thermoelectric cooling systems to protect aquatic wildlife (Feeley, 2006).

CWA §316(b) Cooling Water Intake Structures

This law requires that the location, design, construction and capacity of cooling water intake structures make use of the best technology available to minimize negative environmental impacts, including harm to aquatic wildlife (Feeley, 2006).

The Safe Drinking Water Act (SDWA)

The SDWA protects Americans from contaminants in the public drinking water supply of the United States. It also requires the EPA to set national drinking water standards and creates a federal-state system to ensure compliance, much like the provisions of the CWA. In the case of power plants, their wastewater may contain substances such as mercury, arsenic, and other trace metals restricted by the SDWA's standards. The SDWA, therefore, affects how power plants dispose of these substances (Feeley, 2006).

Climate Change Policies

AB 32

AB 32, also known as the Global Warming Solutions Act of 2006, mandates California to reduce greenhouse gas emissions to 1990 levels by 2020, by way of a statewide cap beginning in 2012. The law directs the California Air Resources Board (CARB) to create the necessary regulations and a mandatory reporting system to track greenhouse gas emissions. The following principles must also be used when implementing the cap (Union of Concerned Scientists, 2005a):

- Distribute costs and benefits equitably
- Prevent consequential increases in air pollution on the local level
- Protect entities that took steps to reduce their emissions prior to AB 32
- Coordinate with other jurisdictions outside of California to reduce emissions

Emissions Performance Standard (EPS)

To help mitigate climate change, the CPUC adopted the emissions performance standard (EPS) on January 25, 2007. The EPS implements Senate Bill 1368 (Perata), which prohibits long-term financial contracts for baseload electrical generation by investor-owned utilities, energy service provides, and community choice aggregators unless the generator complies with a greenhouse gas emissions standard. A contract of more than five years is defined in the EPS as being "long-term" (CPUC, 2006). The EPS also requires that the facility contracted to meet baseload demands have emissions "no higher than those of a combined cycle natural gas turbine." This has been equated to an emissions performance level of 1,100 pounds of CO_2 per megawatt-hour (CPUC, 2007). The EPS is likely to decrease water demand, as combined cycle natural gas turbines are more efficient than single cycle systems, requiring less water per unit of electricity generated.

Crediting Conservation

Electric utilities and water districts interested in water conservation are working on finding ways to allocate credits for conservation measures. By implementing water saving measures, organizations often also save energy (and vice-versa). Additionally, if a utility in Southern California implements water-saving technologies, the total volume of water conveyed by the State Water Project (and pumped over the Tehachapi Pass by the Edmonston Pumping Plant) may be reduced. The Edmonston Pumping Plant, however, is located in PG&E's service territory. Clearly, allocating conservation credits has numerous challenges, many of which are currently being examined by the CPUC. Major players in the California utility market have established a "Water Energy Partnership." This partnership wants to be credited not only when they find ways to directly reduce their overall water use, but also when they identify and use efficient supply options like reclaimed water.

Land Use

Historically, California's power plants were sited on the coast because that is where the bulk of the electricity is used, thus requiring fewer costly high-voltage transmission lines (Ahren, 2000). In addition, and perhaps more importantly, locating plants on the coast gives them access to a virtually unlimited and free supply of water. Despite these benefits of locating plants on the coast, adverse environmental impacts such as thermal pollution and marine ecosystem disruption are becoming increasingly difficult to ignore.

In April of 2006 the California Land Use Commission proposed a resolution stating that it would not approve leases for any new facilities using once-through cooling. As once-through cooling is phased out, California must look to inland water supplies to meet its cooling needs. The paucity of these inland supplies suggests that alternate approaches to electricity generation must be taken. It is still uncertain whether these approaches will be predominantly technological (e.g. switching from coal combustion to IGCC) or will instead focus on increasing the amount of electricity generated from sources such as wind that do not require water for cooling.

Siting

Depending on the primary energy source and conversion technology, there may be restrictive site limits based on the availability of the energy source, the availability of water, aesthetics, or public health concerns. Each fuel source comes with its own unique set of siting challenges.

One of the challenges in siting a nuclear facility is that past nuclear accidents and the risk of future incidents has created very low willingness to live near such a plant. Additionally, nuclear plants require considerable amounts of water for cooling, making the coast an ideal location. As discussed above, however, the CWA does not allow the introduction of new once-through coastal cooling facilities. The Palo Verde plant in Arizona is currently the only nuclear plant in the U.S. that does not sit on a body of water. Instead, the plant uses treated sewage effluent from nearby municipalities for cooling water (APS, 2007).

The wind itself represents one of the biggest limitations to siting wind farms. Sufficient wind resources are not prevalent in all areas, and are often located in undesirable locations, such as extremely rural or densely populated areas. While this characteristic might make siting a wind farm politically more feasible, the demand for the power is remote, requiring more infrastructure and incurring higher costs. Land itself is also a limit; an average wind farm requires 17 acres of land to produce one megawatt of power (California Energy Commission, 2005e). The rural location of most wind farms and the potential to use land for ranching or farming make this aspect less limiting. For example, the Great Plains of the U.S. have plentiful wind resources, but also have desirable agricultural land use. Farmers or land owners can use the land to grow crops or raise cattle, and the wind developer does not need to purchase the land outright, but can lease the land, likely saving high initial capital costs. In other situations, the location of the wind resource, such as off-coast, is undesirable due to the impact on the scenic aspects of the area.

Reliable Baseload

Baseload generation facilities are those facilities that are designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent. Baseload facilities are reliable, constant, and fueled by low-cost fuels such as water, coal, or uranium. A portfolio with a large percentage of energy coming from intermittent sources such as the sun and the wind introduces risk into the system in the form of brown-outs and black-outs.

SB 1368, which became effective on January 1, 2007, prohibits the state's IOUs and municipal utilities from executing power purchase agreements for baseload generation with terms exceeding five years, unless the generating facility meets established greenhouse gas (GHG) emissions performance standards. These standards specify that that the GHG emissions of newly purchased baseload facilities must be less than or equal to a baseload combined-cycle natural-gas-fired plant. RPS-compliant renewables are not exempted from the emissions standard, and must report their emissions (Stoel Rives LLC, 2006). Electricity generation is the source of 20 percent of California's GHG emissions (Figure 68).

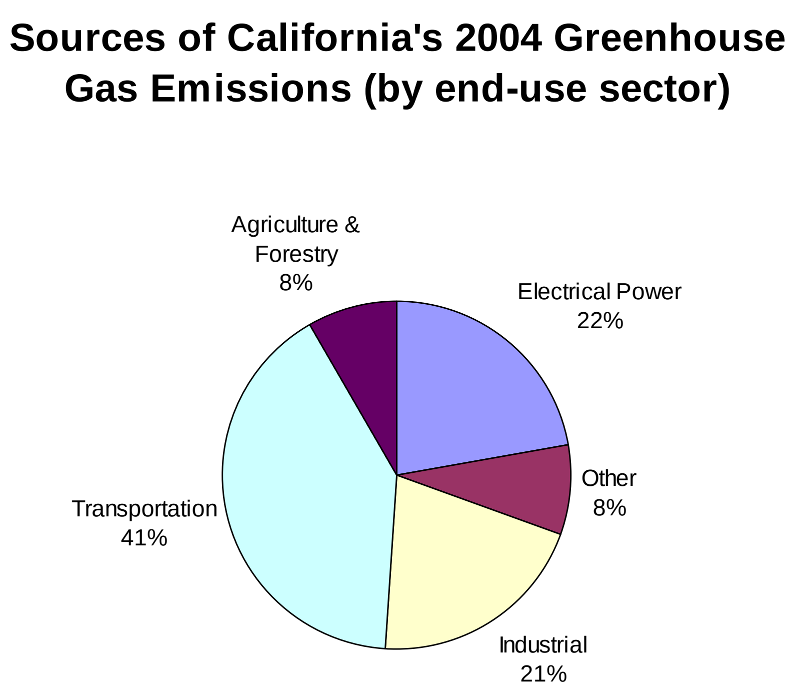

Figure 68. Sources of California's 2004 greenhouse gas (GHG) by percentage (by end-use sector). Includes electricity imports and excludes international bunker fuels) (California Energy Commission, 2006b)

Long-term drought

Climate change in California is likely to result in decreased snowpack and earlier snowmelt, which increases the potential for flood and drought (see Climate Change section for greater detail). These changes in climate affect not only the water sector, but also the energy sector, forcing cities and regions to choose between energy production and water distribution. Ironically, the areas of the nation most prone to droughts are also the areas experiencing rapid population growth (Figure 69), which taxes already limited water supplies.

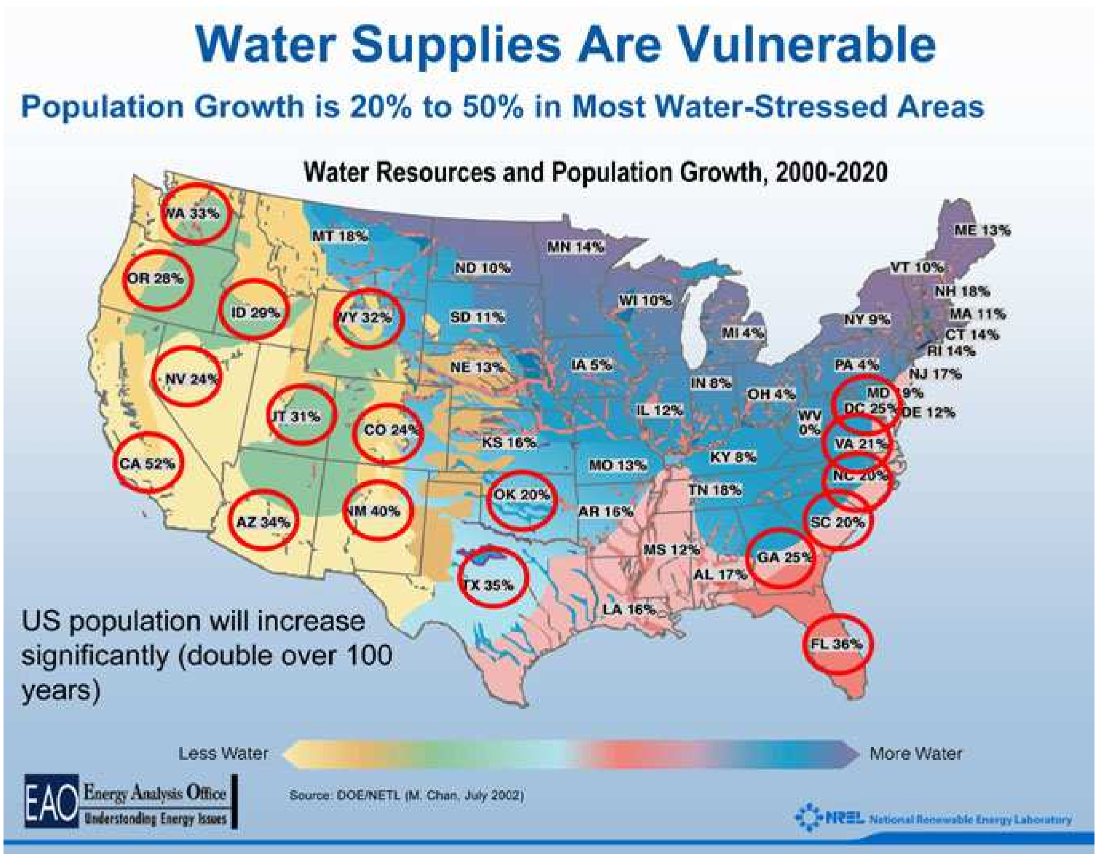

Figure 69. Water resources and population growth (Chan, 2002)

In the case of long-term drought, disputes over water rights will likely emerge between major users of water. Major users which may be involved in such disputes include the agriculture and energy sectors which both require substantial quantities of water to operate.

Shortages of water beget shortages of electricity. During the California drought of 1991, hydroelectric capacity was notably diminished due to a reduction in run-off from the winter snow pack. According to a report issued by the DWR, "Californians had to pay $455 million more last year [1991] in energy costs directly related to the drought" (New York Times, 1992). Clearly, any fuel source requiring a significant amount in any step of the electricity generation process is vulnerable to disruptions during a drought. Biomass is one such example, as dedicated biomass crops require significant amounts water for growth. Wind power output, on the other hand, is near-immune from changes in water supply.

Technological Improvement Potential

Our research findings show current water use in electricity generation and methods for reducing water demands. We must consider, however, that the technologies used in the energy generation process will improve over time. Improvements in the energy capture efficiency of conversion technologies alone will decrease the amount of water needed to produce a unit of electricity. Furthermore, there is great potential to improve generation process technologies such as dry cooling. These technologies have the potential to decrease water use dramatically and their implementation will be far more widespread if the parasitic load they create, or efficiency loss to the plant, is reduced. Improvements in energy capture efficiency will not only increase the profitability of power generation, but these improvements can also lessen the environmental impacts and the overall resource footprint of electricity generation.

While research into efficiency improvements is occurring throughout the energy sector, several primary energy source areas (such as solar PV) are verging on large efficiency gains (NREL, 2007c). For some emerging technologies, like fuel cells, these efficiency increases will overcome the existing cost barrier to wide-scale commercial implementation (USDOE, 2006b). Cost is often the largest barrier to wide-scale use of a technology, and as energy capture efficiency improvements decrease cost per kWh or MWh, these improvements are a chief way to encourage the growth of water friendly and carbon friendly generation technologies.

Increased energy capture efficiency in all generation technologies would be valuable in terms of generation cost and resources use; however, there are several examples of possible technological improvements that would greatly improve water use in the energy sector. These improvements include the increased energy capture efficiency of those generation technologies that are already low water users (would lower costs and help overcome price barriers), improvements in dry and recirculating wet cooling technologies (could directly save large amounts of water), and technology improvements in zero liquid discharge (such that it becomes more cost effective and widespread).

There is a considerable amount of research currently being pursued by large government affiliated research institutions and laboratories such as NREL, electric utilities, energy sector research organizations such as EPRI, and other private, public, and non-governmental organizations. Considering past trends in technological development of all commercial sectors, it is reasonable to expect future that technology advancements may positively impact the water needs of energy sector.

Conclusions and Recommendations

This research provides a tool to support integrated planning between energy and water utilities, and also helps government agencies integrate water considerations into planning for future energy supplies. Progress in greater integrated planning is growing, on local, state, national levels. Where possible, co-location of facilities can improve resource efficiency; for example, Burbank Water and Power meets all of its power plant's water needs by drawing reclaimed water from the neighboring wastewater treatment plant (Owen, 2007).

Meeting future electricity demand has inherent challenges. While decreasing our use of non-renewable sources of energy may decrease greenhouse gas emissions and provide greater political security; it should not be done in a manner that would compromise energy reliability. In California, baseload generation (see Reliable Baseload section for further information), is predominantly met by non-renewable sources of energy, such as nuclear and natural gas. Additionally, California relies primarily on natural gas to meet peak demand, both seasonally and daily. The ability of renewable energy sources to meet current demand, in terms of both total volume and timeliness, may be limited. Waste-based biogas could be used for baseload electricity generation, but it is somewhat limited in volume. Likewise, while coupling fuel cells with solar photovoltaics addresses the intermittent nature of solar power, the cost of fuel cell technology is currently prohibitively high.

Other environmental impacts of electricity generation should also be considered alongside water resource impacts. Combustion of fossil fuels releases greenhouse gas emissions and other emissions to air and water, which must be considered. Habitat loss and biodiversity impacts represent additional concerns. For example, covering the solar-rich deserts of California with solar panels or wind farms may have negligible consequences for water resources, but may have significant impacts to regional biodiversity. Despite our concerns about water use for geothermal or bioenergy based generation, they do offer other benefits, including reduced GHGs. We do not, however, necessarily recommend their development. As our data demonstrates, certain types of geothermal or bioenergy production have only minimal impacts on water resources. Additionally, impacts on water resources may be region-specific. For example, the production of dedicated energy crops may be limited in arid states such as California, but may be more viable in wetter climes.

Cost also must be considered as a primary challenge to meeting future energy demands. A full economic analysis of costs and benefits should be completed prior developing the future energy portfolio. Finally, the life cycle impacts of electricity generation facilities, including solar photovoltaic panels, thermoelectric power plants, and hydroelectric dams, must be considered, and represent an important research gap.

This analysis elucidates several key points.

- A water-efficient energy portfolio can be obtained from both primary energy sources and cooling technologies. Utility investments should consider the impact of power generation on freshwater resources, and increase investment in water-efficient energy generation such as solar photovoltaics, wind power, and coal gasification (IGCC).
- Policies that encourage conservation of water can greatly assuage future water requirements. For example, conservation credits for energy utilities that implement programs to reduce water use will help reduce water and electricity use.
- Integration of water and energy infrastructure planning offers several benefits. Increasing the use of reclaimed water in power plants reduces demand on traditional freshwater sources. Additionally, co-locating wastewater treatment facilities and power plants is a prime example of integrating water and energy infrastructure.
- Many research gaps still exist that need to be addressed. Thorough life-cycle analysis of electricity generation, including water use at each stage of the electricity generation process is needed to understand the full water requirements of electricity generation. Additionally, a feasibility analysis of water-efficient energy portfolios is needed to facilitate reliable infrastructure growth which will be able to meet future demands since the most appropriate mix of primary energy sources and cooling technologies depends on both available resources and patterns of demand.

Appendices

Appendix A: Climate Change Analysis

Over the next century, anthropogenically-driven climate change will likely hold significant consequences for California's interdependent water and energy systems. Particularly in regions where water supplies are overallocated, understanding the possible effects of climate change and preparing for them is essential. Predictions of temperature and precipitation changes vary, depending on the general circulation model (GCM) and the greenhouse gas emissions scenario employed. While all models predict an increase in regional temperatures, they disagree on both the magnitude and direction of changes in regional precipitation. Two climate change scenarios, projected by the Parallel Climate Model (Washington, 2000) and the Hadley Centre Model, version 2 (Johns et al., 1997), bracket the range of possibilities for temperature and precipitation changes in California. The following sections present their potential impacts on the water and energy sectors.

California, by most projections, will experience moderate warming; it lies between the more substantial warming projected for high latitudes and the milder warming expected in subtropical latitudes. Similarly, due to its coastal location, it falls between the more significant warming likely over the North American continent and the mild warming predicted for the Northern Pacific Ocean (Dettinger et al., 2004). The Western U.S. may, however, be particularly sensitive to climate change; small changes in temperature may be accompanied by more dramatic changes in patterns of precipitation (Coquard et al., 2004). The Parallel Climate Model and the Hadley Centre Model realistically simulate California's historical climate, and are frequently employed by environmental scientists in California. The Parallel Climate Model (PCM) projects mild global warming and a small increase in global precipitation; the western United States, however, will likely experience decreased rates of precipitation. The Hadley Centre Model (HCM) predicts a more substantial temperature increase and an increase in both global and regional precipitation (Figure 70). This analysis presents a brief description of the models and a more comprehensive description of their projected impacts on water availability in California. In addition, we consider secondary impacts of climate change (for example, on electricity generation and energy demands) and outline potential mitigation tactics.

This analysis focuses on three hydrologic regions, each of which possesses important implications for water and energy supplies in California: the Central Valley (Sacramento and San Joaquin Rivers), the Colorado River Basin, and the Columbia River Basin. The Central Valley has an average annual runoff of approximately 33.6 million acre feet, or 48% of all of California's natural runoff (DWR, 1951). Two thirds of this originates in the Sacramento Valley, and supports California's urban areas and extensive agricultural sector. The Colorado River has historically supplied up to 5.3 million acre feet of water to Southern California. Even if limited to its legal annual allocation of 4.4 million acre feet, the Colorado River supplies half of Southern California's annual water use (DWR, 2005). In addition, Hoover Dam generated, on average, 4.8 billion kilowatt hours annually between 1996 and 2005 (U.S Bureau of Reclamation, 2006); Davis and Parker Dams generated an additional 1.5 – 2.5 billion kilowatt-hours (U.S Bureau of Reclamation, 2006) and (U.S Bureau of Reclamation, 2006). Similarly, the Columbia River Basin's massive hydroelectric generators deliver significant amounts of electricity to California during the summer months. The impact of climate change on these three basins, therefore, will likely have important consequences for California's water and energy resources.

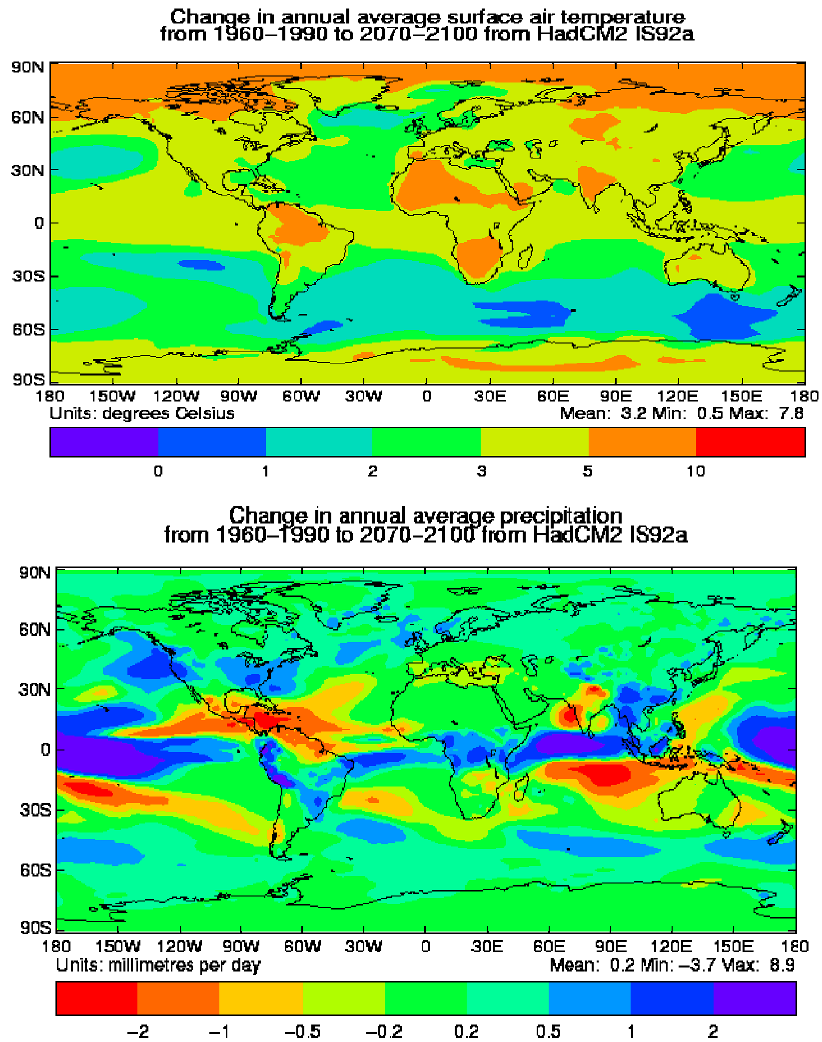

Figure 70. Projected changes in average annual surface air temperature and precipitation from the Hadley Centre Model 2, between the period 1960-1990 and 2070-2100 (Hadley Centre for Climate Prediction and Research, the Met Office).

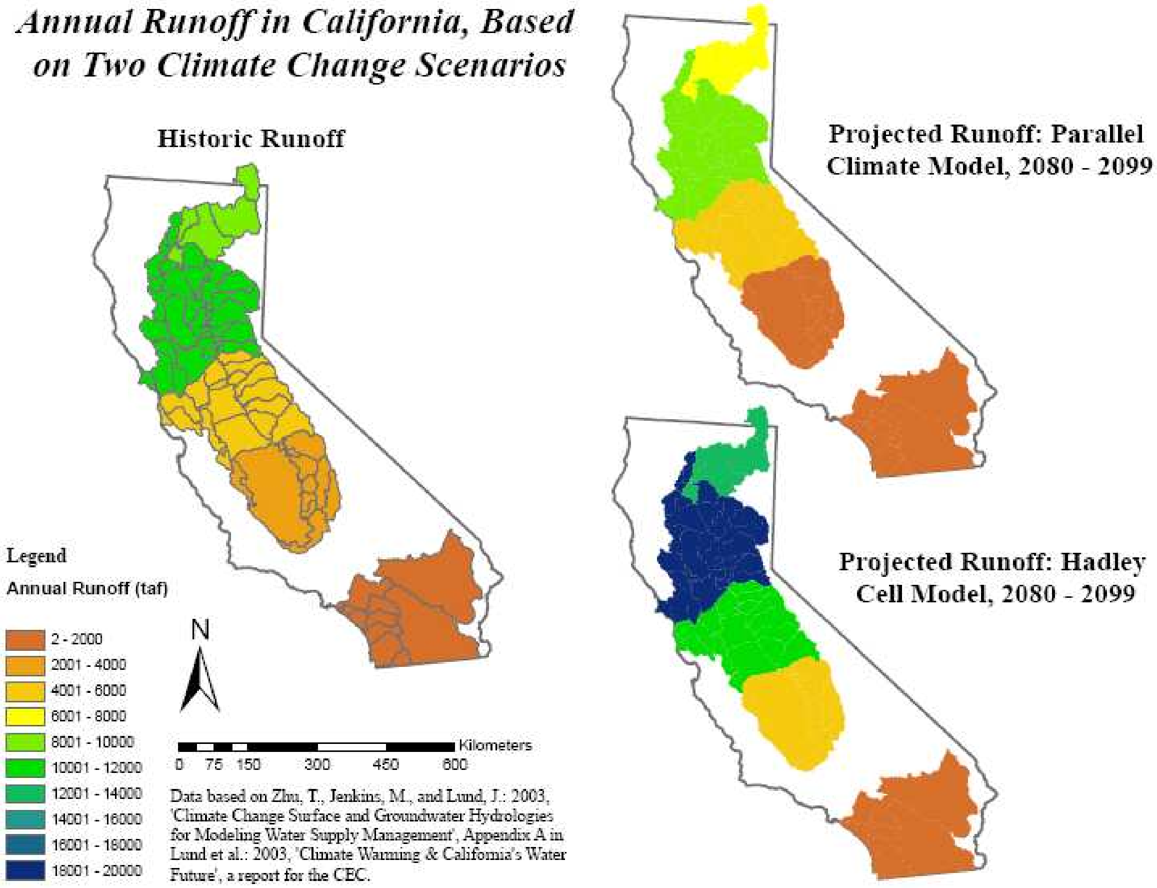

Figure 71. Projected impacts of two climate change scenarios on the water resources of California.

Climate Change Scenarios

Parallel Climate Model

The Parallel Climate Model (PCM), developed by the Department of Energy and the National Center for Atmospheric Research, couples atmosphere, ocean, sea-ice, and land-surface systems (for more details, see Washington et al. (2000) and Dai et al. (2004)). The PCM realistically represents historical climate fluctuations and ocean temperatures. Its higher resolution (compared to other models) contributes to a higher amplitude El Nino-La Nina cycle than seen in previous models and more substantial interannual variability (Zhu et al., 2004).

The following sections summarize the impacts of the PCM-simulated temperature and precipitation changes on several river basins in California, the Colorado River basin, and the Columbia River basin under "business as usual" (BAU) emissions of greenhouse gases (GHGs). The findings are based primarily on several peer-reviewed studies published in the journal *Climatic Change* (Christensen et al., 2004;

Dettinger et al., 2004; Lettenmaier et al., 2004; Payne et al., 2004; Stewart et al., 2004; and Vanrheenen et al., 2004) that use statistical and dynamic downscaling techniques to elicit regional changes from the global climate change model. These studies simulate regional climate for five periods:

1. A historic period, 1870 – 1999, which is used with observations to calibrate the model;
2. A "Control" period, from 1995 – 2048, in which GHG and aerosol concentrations are held at 1995 levels;
3. Future Period 1, 2010 – 2039, with GHG concentrations increasing under BAU projections;
4. Future Period 2, 2040 – 2069, with BAU projections; and
5. Future Period 3, 2070 – 2098, with BAU projections.

To simulate changes in surface runoff, baseflow, evapotranspiration, soil moisture, and snowpack, the analyses use the Variable Infiltration Capacity macroscale hydrology model developed by Liang et al. (1994 and 1996). Driven by time series data on temperature, precipitation, and wind patterns, this hydrology model creates continuous daily streamflows. In addition, each analysis uses a regional model to simulate management of the water resources, including water deliveries, flood control, hydroelectric generation, maintenance of environmental flows, and reservoir management. The three regional analyses use different hydrologic models: in the Sacramento-San Joaquin Basin, Vanrheenen et al. (2004) developed a model termed "Central Valley Model"; in the Columbia River basin, Payne et al. (2004) apply the Columbia River Simulation Model (described in Hamlet & Lettenmaier, 1999); and in the Colorado River basin, Christensen et al. (2004) apply a simplified version of the Colorado River Simulation System (U.S. Bureau of Reclamation, 1985).

Temperature

In the western United States, the majority of precipitation falls in the form of snow. Small changes in temperature can, therefore, have disproportionate effects on the timing of snowmelt and seasonal runoff. In addition, elevated temperatures can increase rates of evapotranspiration. In the western U.S., the Parallel Climate Model predicts an average annual temperature increase of approximately 2° C by the end of the 21st century, relative to the Control climate simulation. The Control simulation exhibits average temperatures 0.5° C warmer than the observed historical period.

The three hydrologic regions exhibit slightly different patterns and magnitudes of warming. In California, the Control simulation projects slightly warmer temperatures than those observed in the recent historic period; temperatures in Periods 1, 2, and 3 are projected to increase (relative to the Control simulation) by 0.5° C, 1.2° C, and 1.9° C, respectively. Additionally, in future periods, temperatures are projected to increase more significantly in the summer months (Vanrheenan et al., 2004). Simulated temperatures in the Colorado River basin show more substantial increases, with the Control climate 0.5° C warmer than historic observation, and Periods 1, 2, and 3 showing simulated increases of 1.0° C, 1.7° C, and 2.4° C, respectively. In the Colorado River basin, the model predicts more significant warming during winter and spring months (Christensen et al., 2004). The Control simulation for the Columbia River basin projects a slight warming over historic observations, and temperature increases (relative to the control simulation) of 0.5° C, 1.3° C, and 2.1° C for Periods 1, 2, and 3. The small warming projected during the first period (0.5° C) does not differ statistically from observed interannual variability. While warming is predicted for all months, modeled temperature increases are more substantial during the winter and summer seasons (Payne et al., 2004); (Figure 72).

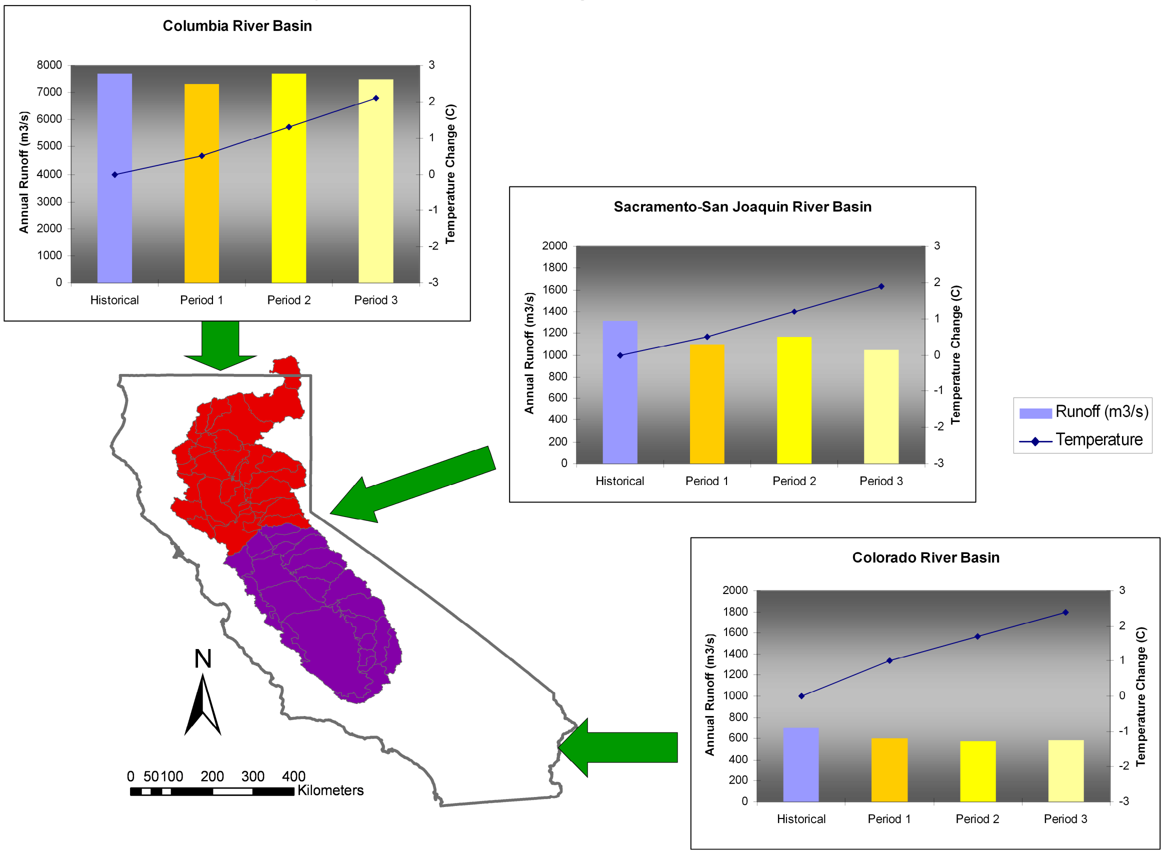

Figure 72. Change in temperature and annual runoff under climate change, as projected by the Parallel Climate Model. The three periods modeled under a "business as usual" emissions scenario are 2010-2039, 2040-2069, and 2070-2098. Note the differences in scale on the primary y-axes.

Annual Precipitation

Similar to temperature, projected changes in annual precipitation vary between the three major basins. On average, precipitation is expected to decrease in California for all periods, with runoff declines most severe in areas where snow is an important part of the water balance (the Sierra Nevada Mountains and the coastal mountains in the northwest). The model projects smaller decreases in the drier southeastern and northeastern areas of California. The Sacramento and San Joaquin Rivers drain the western slopes of the Sierra Nevada Mountains and supply a substantial portion of water used in the State of California; these important drainage basins are projected to see decreases in winter and spring precipitation on the order of 10 – 25% (approximately 10 – 35 mm/month) for all future periods (Vanrheenen et al., 2004).

In the Colorado River basin, the model predicts overall precipitation decreases of 3%, 6%, and 3% (12, 22, and 12 mm) in Periods 1,2, and 3, respectively. Regional variations, however, are present: the Rocky Mountain headwaters of the Colorado are projected to experience a 0 – 10% increase in precipitation, while northwestern Arizona is projected to see a 10 – 15% decrease in precipitation. Because the majority of precipitation (90%) in the Colorado River basin falls in the Upper Basin and runoff is dominated by snowmelt (70% of annual runoff originates as snowfall in the high Rocky Mountains), the effect of climate change on snowpack is of particular concern. With a basin-wide average annual precipitation of only 40 cm and a low runoff ratio (13%), small changes in precipitation and snowpack have a disproportionate effect on available water supplies (Christensen et al., 2004); (Figure 73).

In the Columbia River basin, the simulations project little change in the average annual precipitation, significant shifts in the seasonality of precipitation and runoff, and significant interannual variability. Winter precipitation, which dominates annual precipitation, is predicted to decline by 3% (approximately 30 mm) in Period 1, and increase by 5% (50 mm) and 1% (10 mm) in Periods 2 and 3, respectively (Payne et al., 2004).

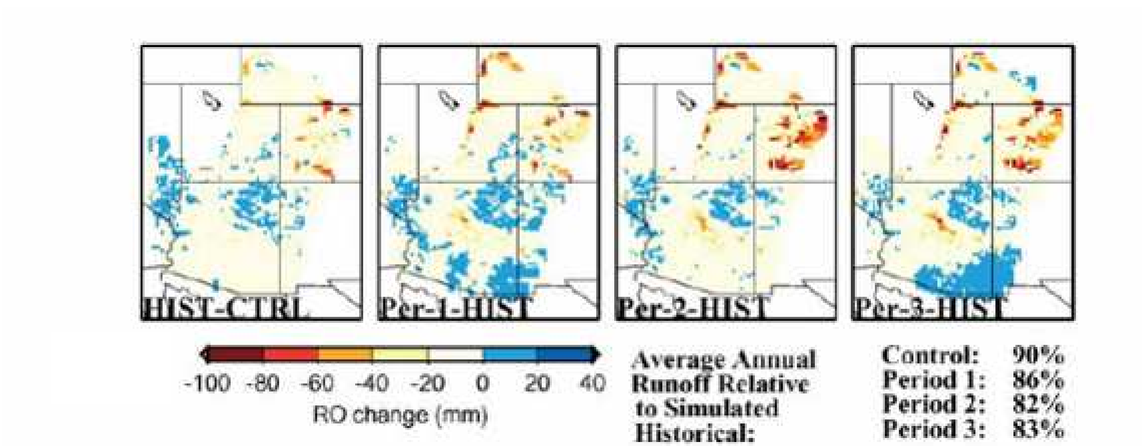

Figure 73. Change in runoff in the Colorado River Basin, relative to the observed historical runoff. Figures include the control simulation, and Period 1, 2, and 3 under "business as usual" emissions scenarios. Note the increase in runoff in Southern Arizona and the substantial decreases in runoff from the Rocky Mountain region (Christensen et al., 2004).

April 1 SWE

As described above, snowpack represents an important water reservoir; higher temperatures and an earlier spring runoff may have important implications for water resources management. In California, the melting snowpack is the source of 20% of the average annual runoff; in addition, this runoff provides 35% of the state's *useable* surface water (DWR, 2005). Snowpacks at higher elevations typically have less sensitivity to changes in temperature, while a temperature increase of a few degrees may induce considerable melting at lower elevations. The April 1 snow water equivalent (SWE) serves as a useful indication of changes in snow accumulation and the timing of snowmelt.

Elevation varies substantially across the Sierra Nevada Mountains; the high elevation mountains in the southern region drain into the San Joaquin River and have snowpacks that are projected to have little sensitivity to temperature changes. In this region, observations from the past half century indicate that several degrees of warming has resulted in only a 10 – 20% decrease in April 1 SWE. The Northern Sierra Nevada Mountains, however, have much higher spatial variability and, overall, lower elevations. Snowpack in this region, therefore, exhibits a more varied response to temperature increases (Howat and Tulaczyk, 2004). Vanrheenan et al. (2004), however, project April 1 SWE to decline by 26, 38, and 52% during future periods 1, 2, and 3 in the Sacramento-San Joaquin River basin, with the greatest proportional changes occurring in the Northern Sierra Nevada. In addition to the dramatic decreases seen in future period 3, significant decadal variability is projected.

April 1 SWE in the Colorado River basin is expected to decline in both the Control period and future periods 1, 2, and 3, by 14, 24, 29, and 30%, respectively (Christensen et al., 2004). In the Columbia River basin, Payne et al. (2004) project April 1 SWE declines of 22, 23, and 39%, relative to the historic (observed) SWE.

Changes in Runoff, Spatial, and Temporal Patterns
Changes in temperature and precipitation have implications for both the total volume of runoff and the timing of runoff. As described above, regional topography makes the water resources in some regions particularly susceptible to small changes in temperature.

In California, changes in the total volume of annual runoff are projected to be more severe in the Southern Sierra Nevada (San Joaquin drainage basin) than in the Northern Sierra Nevada (Sacramento drainage basin). In addition, the San Joaquin River model exhibits a stronger shift in seasonality, resulting in more severe streamflow reductions during late summer months (Vanrheenan et al., 2004). Increased variability in wintertime precipitation conditions (i.e. the proportion that falls as rain versus snow) is projected to contribute to more variable spring fractions of annual flow (Dettinger et al., 2004). These projections mimic patterns observed over the last century: from 1890 – 2002, precipitation decreased in the central and southern portions of California, while increasing slightly in Northern California; annual variability increased throughout the state (DWR, 2006). The total annual delta inflows are projected to decrease by 16% (210 m^3/s), 11% (145 m^3/s), and 20% (263

m^3/s) in Periods 1 – 3, with San Joaquin River inflows decreasing more substantially, by 33% (145 m^3/s), 29% (127 m^3/s), and 44% (193 m^3/s) for Periods 1 – 3. Modeled monthly inflows vary significantly between the Sacramento and San Joaquin Rivers: In the Sacramento River system, average monthly inflows during the summer and fall months are predicted to *increase* in periods 2 and 3, while modeled average monthly inflows decreased during all periods in the San Joaquin River system (Vanrheenan et al., 2004).

Three drainage basins, the Merced, Carson, and American, represent the variation between the southern and northern Sierra Nevada. In the lower-elevation American River basin, wintertime rainfall and snowmelt dominates runoff (approximately two thirds of annual runoff), with springtime snowmelt comprising the remainder. In the other two basins, with higher average elevation, springtime snowmelt dominates runoff. Relative to historical simulations of springtime flows, the April-July fractions of annual streamflow are projected to shrink by 14% (112 m^3/s) in the Merced, 10% in the Carson, and 7% in the American over the next century. In addition, the total volume of April – July runoff is diminished by 16% (113 m^3/s) in the Merced, 5% (63 m^3/s) in the Carson, and 29% (261 m^3/s) in the American (Dettinger et al., 2004).

In the Colorado River basin, runoff is projected to decrease 10% (70 m^3/s) in the Control simulation, and 14% (98 m^3/s), 18% (126 m^3/s), and 17% (119 m^3/s) in Periods 1, 2, and 3. These modest changes in streamflow, however, have a disproportionate impact on reservoir storage, which models predict will shrink by 36, 32, and 40% - the equivalent of 14, 13, and 16 km^3 – for Periods 1, 2, and 3. Because of the high storage to runoff ratio in the Colorado River basin (approximately 4:1), seasonal shifts in runoff do not have a significant impact on water resources management; however, this also implies that changes in reservoir management cannot effectively mitigate climate change (Christensen et al., 2004).

Average *annual* runoff for the Columbia River basin under the PCM scenario is projected to change little: -5% (390 m^3/s), 0%, and -3% (230 m^3/s) for Periods 1 – 3, respectively. The seasonality of runoff is predicted to shift, however: during periods 2 and 3, runoff is projected to increase in winter and spring, but decrease during summer months. Simulations of runoff in period 1 demonstrate diminished summer flows but do not suggest a shift in seasonality (Payne et al., 2004). Reduced mountain snow pack and a shift in spring runoff (approximately 1 month earlier in 2050) will likely be the most significant challenge in the Columbia River basin. In many places, reservoir capacity cannot handle the projected increases in runoff (Barnett et al., 2005), which has important implications for both the timing and amount of power generated in hydroelectric facilities.

Finally, increased temperatures are predicted to result in significantly earlier snow melt in mountainous regions in the Western U.S. The timing of snowmelt has much greater sensitivity to temperature increases than to changes in precipitation; Stewart et al. (2004) projects the temporal centroid of streamflow of annual runoff to occur 30 – 40+ days earlier in many parts of the West. This shift in timing changes much of the snowmelt runoff into a flood hazard, rather than a valuable natural resource, and in effect, lengthens the summer dry season by an additional month. To effectively counteract the impact of increased temperature on the timing of runoff, precipitation must increase significantly (by Stewart et al.'s estimate, in several large rivers in the Pacific Northwest, annual precipitation must increase by approximately 8 meters to counteract 1° C of springtime warming).

Changes in Variability and Reliability

For resource management, the *reliability* of water and energy supplies is as important as the total amount available. Balancing the need for flood control with instream flow requirements, hydroelectric power generation, reservoir storage, and deliveries to different end-use sectors becomes increasingly difficult under greater environmental variability. In the Sacramento-San Joaquin River system, climate anomalies (particularly wet or dry periods) are projected to become more extreme and inter-annual differences more variable in future periods. Simulations suggest that the reliability of meeting fish and environmental flow targets will decline with warming, while the reliability of flood control will increase (Vanrheenan et al., 2004).

In the Colorado River Basin, reservoir depletion results in several types of restrictions: Releases from Glen Canyon Dam (Lake Powell) to the lower basin states are not diminished until the lake is at its dead storage volume (at which point releases are impossible). This policy ignores the minimum power pool level. As the water level in Lake Mead drops, Level 1 and Level 2 restrictions are imposed: Level 1 shortages limit water deliveries to the Central Arizona Project and the Southern Nevada Water Authority; Level 2 shortages restrict water deliveries to all entities, proportionally. Using historical streamflows (1950 – 1999) and the quantity demanded in 2000, Christensen et al. (2004) project Level 1 shortages to occur in 60% of years during the simulated Control period, and Level 2 shortages in 28% of years during this period. In future periods 1, 2, and 3, Level 1 shortages are projected for 92, 89, and 100% of the years, respectively; Level 2 restrictions are projected to be employed in 77, 54, and 75% of years. These predictions assume that demand in the Upper Basin does not increase; with increasing withdrawals in the Upper Basin, the reliability of deliveries is projected to decrease by an additional 5 – 20%. Finally, at least once in each simulated future period, the total water system storage falls such that Lake Mead is below its inactive storage capacity and Lake Powell holds only its dead-pool storage capacity – i.e., the system fails entirely (Christensen et al., 2004).

The simulations of the Columbia River system exhibit less dramatic consequences. With the projected earlier runoff of snowmelt and current instream flow requirements, reservoir levels are predicted diminish substantially in autumn months, resulting in diminished sustainable firm power deliveries by approximately 10 – 20% (average annual generation is 144,540 GWh[21]. However, altering reservoir management and flood control policies may mitigate these decreases (Payne et al., 2004).

Hydroelectric Supplies

With earlier spring snowmelt and possible increased flood intensity, flood control may necessitate greater drawdown of reservoirs. By releasing stored water earlier in the spring, before California's peak power demand in late summer and early fall, hydroelectric generation is predicted to decrease. In the Central Valley system, hydropower production is expected to decrease by 10, 6, and 12% in Periods 1, 2, and 3 (Vanrheenan et al., 2004). Lund et al. (2003) estimates a more dramatic reduction of hydropower production – a 30% decrease in revenues (equivalent to $39 million annually) by 2100. Currently, hydropower represents, on average, approximately 15% of electricity consumed in California (approximately 11,000 GWh), but ranges between 9 and 30% (5,000 to 17,000 GWh), depending on hydrologic conditions (Franco and Fagundes, 2005); (Lund, 2003).

On the Colorado River, Glen Canyon and Hoover Dams are particularly sensitive to reservoir drawdown, whereas Davis and Parker Dams are run-of-the-river dams that continue to generate hydropower regardless of reservoir levels. Overall, the Colorado River system annual hydropower outputs are projected to decrease by 56, 45, and 53% (3700, 2600, and 3400 GWh), relative to simulated historical production (8100 GWh) (Christensen et al., 2004). As described above, Columbia River basin hydroelectric generation competes directly with instream fish flow requirements, and in absence of altered reservoir management, is predicted to decrease by 10 – 20% (Figure 73); (Payne et al., 2004).

Hadley Centre Model

Similar to the Parallel Climate Model, the Hadley Centre Model uses a coupled atmosphere and ocean model to project global climate change. In California, it simulates the seasonal and spatial variations in historical precipitation well (Kim et al., 2002), but under a "business as usual" scenario of greenhouse gas and aerosol emissions, projects a warmer, wetter future than that predicted by the Parallel Climate Model. In some regards, the Hadley Centre Model (HCM) represents a less dire scenario for California's water and energy resources because annually, more water is projected to be available, and more hydroelectric energy may be generated. However, the temperature and precipitation increases will still demand innovative, alternative management strategies, for numerous reasons. Even though average annual precipitation is predicted to increase relative to the historic, observed precipitation, the majority of additional precipitation will likely fall in the winter, creating new challenges for flood control and reservoir management. Increased temperatures are projected to lead to earlier snowmelt runoff, effectively extending

[21] Based on 16,500 MW for 365 days, 24 hours a day

the summer dry season. The following analysis focuses primarily on California, ignoring the other western hydrologic regions for three main reasons:

1. Greater availability of water and energy resources within the state implies that out of state supplies will be less essential and less relied-upon;
2. The increased water supplies dictates “in house” management strategies; and
3. A comprehensive assessment of the impacts of the Hadley Centre Model on the hydrologic resources of the Western United States has not been undertaken.

Finally, because California may more easily adapt its water and energy systems to the changes projected by the Hadley Centre Model (relative to the Parallel Climate Model), the impacts of the HCM are presented in less detail.

Temperature

The Hadley Centre Model projects an average global temperature increase of 3.2°C by the late 21st century, with California warming by 3 – 5°C ("Hadley centre model website"). In addition, the model predicts more significant warming during winter months.

Annual Precipitation, Runoff, and Available Water

By the middle of the 21st century, average annual precipitation over the Western United States is projected to increase by 2 – 6 mm (Kim et al., 2002). The largest projected increases occur in the Southwestern Region (including California), and winter precipitation increases more significantly than summer. During the winter, a greater percentage of precipitation is predicted to fall in the form of rain except at high elevations (above 2500 meters) (Kim et al., 2002).

Using CALVIN, an integrated economic-engineering model of California’s water system, Lund et al. (2003) project increases in runoff and available water supplies over three future periods: 2010 – 2039, 2050 – 2079, and 2080 – 2099. Runoff from the Sierra Nevada Mountains, which makes up 72% (1,103 m^3/s) of the annual inflow into California’s inter-tied water system, increases in simulations of these three periods by 36%, 46%, and 77% (approximately 400, 500, and 850 m^3/s), respectively, with the bulk of increased runoff occurring during winter months. Accounting for valley floor runoff contributions, increased evaporation from reservoirs, and groundwater recharge, the total projected increase in water inflows is slightly more. The annual *available* water supplies, however, assuming no changes to current reservoir storage or infrastructure, is only predicted to increase by 11%, 7%, and 12% (120, 80, and 130 m^3/s) during the three periods.

Changes in Runoff, Spatial, and Temporal Patterns

The Southern Sierra Nevada mountains, with higher average elevation, are projected to see a greater increase in runoff than the Northern Sierra Nevada. In future periods

1 and 2, simulated runoff decreases during the dry season, but *increases* slightly in future period 3 (Zhu et al., 2006).

With increased temperatures, snowpacks are projected to melt at an earlier date, and a greater proportion of winter precipitation will likely fall in the form of rain. As a result, the HCM predicts a dramatically higher likelihood of flooding at the end of the 21st century (Figure 74); (Lund et al., 2003). Finally, if snowpack melting and runoff occurs significantly earlier in the spring (by 30 – 40 days), as Stewart et al. (2004) found in modeling the temperature sensitivity of snow under the Parallel Climate Model, California may experience extended drought conditions in late summer months *regardless* of annual increases in precipitation.

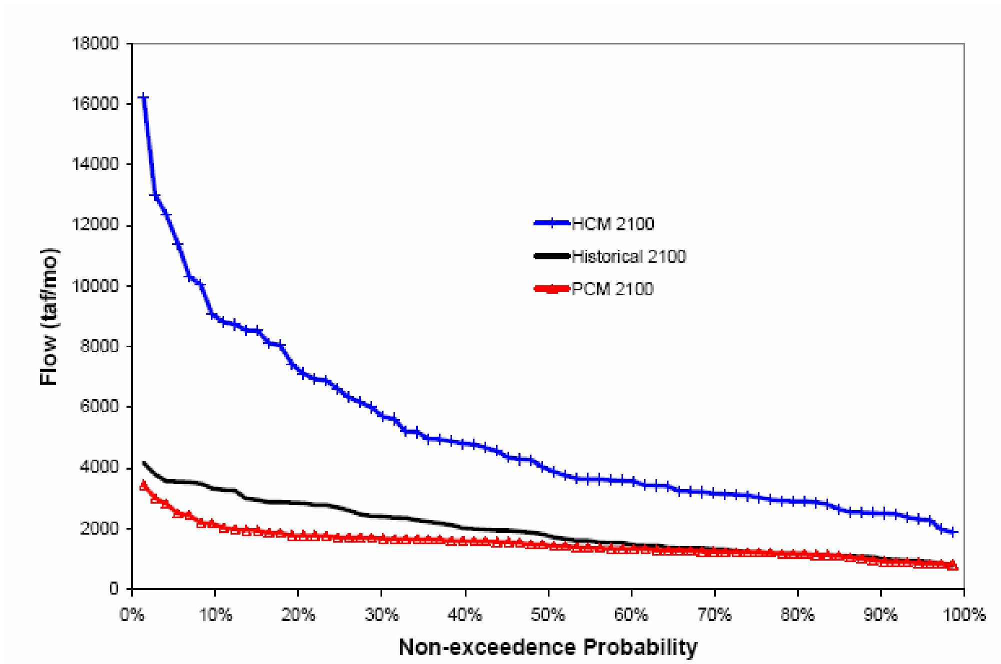

Figure 74. Likelihood of flood flows on the Sacramento River, above its confluence with the American River (Lund et al., 2003).

Hydroelectric Supplies

Provided that reservoir and dam operation can accommodate the increased flood peaks, hydropower production may increase significantly by the end of the 21st century. In fact, in the CALVIN modeling system, revenues generated from hydropower production are projected to be much higher, at $248 million annually, compared to the current revenues of $163 million (Lund et al., 2003).

Additional Implications

Energy Demand
In addition to its direct effects on water availability and hydroelectric generation, climate change may have secondary effects on both water and energy demand in California. Average daily temperatures show a direct relationship to energy use; on exceptionally cold days, customers use more electricity for indoor appliances and heating, and on higher temperature days, customers use more electricity cooling indoor areas (the lowest energy demand corresponds to an outside temperature of approximately 12° C, or 55° F) (Franco and Sanstad, 2006). In addition, an increase in summertime daily temperatures, when demand peaks, has important implications for supply management.

Predictions of future average and peak energy demand are formulated, based on an empirical relationship between annual energy demanded and average daily temperatures, and the relationship between peak energy demanded and maximum daily temperatures. Table 24 presents a comparison of the projected impact of climate warming under the Parallel Climate Model and the Hadley Centre Model for future periods, 2005 – 2034, 2035 – 2064, and 2065 – 2099. The Hadley Centre Model warming employs the A1Fi emissions scenario, while the Parallel Climate Model uses the A2 emissions scenario (both described in detail in the Intergovernmental Panel on Climate Change Special Report: Emissions Scenarios).

Table 24. Change in electricity demanded under future projections of climate change (Franco and Sandstad, 2006).

Model	Period	Annual Electricity Demand (% Increase)	Peak Electricity Demand (% Increase)
PCM A2	1	1.2	1.0
	2	2.4	2.2
	3	5.3	5.6
Hadley Centre Model (3) A1Fi	1	3.4	4.8
	2	9.0	10.9
	3	20.3	19.3

Several other factors are important to consider in electricity supply management. For example, in addition to overall changes, the variability of daily temperatures increases under the Hadley Centre Model projections; by the end of the 21st century, the standard deviation of simulated daily temperatures increases by more than 50%. In addition, the preceding analysis bases energy supply and demand on the current demographics of California, and ignores the trend of increasing development in the warmer interior areas of the state. Finally, while climate change may drive consumption, demographic trends, economic growth, changes in energy markets, and other policy decisions also affect demand; these changes should not be ignored in future planning (Franco and Sanstad, 2006).

Regardless, preparing for the impacts of climate change is essential. Several tactics may help mitigate its impact on California's energy system. Photovoltaics, for example, mimic the diurnal demand for electricity, and may effectively supplement energy supplies (Borenstein, 2005, as cited in Franco and Sanstad, 2006). Alternatively, demand may be reduced by reducing the heat island effect of urban areas or implementing conservation techniques.

Management Challenges and Mitigation Strategies

Sectors affected by changes in water availability
In California, certain sectors will likely bear a disproportionate share of the impacts of climate change. The CALVIN economic-engineering model projects that the Central Valley agricultural users will experience the greatest impacts of climate change. While the wetter HCM scenario predicts increased water availability, the drier PCM scenario projects water availability reduced by one third. Periods of drought, which become more likely under PCM projections, have a significant effect on the agricultural industry, so much so that with the climate changes predicted by the PCM, much of the Central Valley agricultural industry may disappear by the end of the 21st century. Regardless, in the year 2100, the agricultural sector is projected to continue using the most water in the state of California (Lund et al., 2003).

Urban users, with their higher willingness-to-pay, may employ other water source technologies, such as wastewater reuse and desalination, and are not projected to be dramatically affected by climate change. Additionally, in simulated comparisons with the agricultural sector, climate change has a relatively minor impact on patterns of urban demand. In urbanized Southern California, conveyance capacity is anticipated to be the limiting factor. For example, in the year 2100, models suggest that the Tehachapi pumping facility will pump at its maximum capacity for every month *regardless* of the climate change scenario (Lund et al., 2003).

Finally, meeting environmental flow requirements is projected to become prohibitively expensive in some regions of California. Under PCM projections for 2100, most minimum flow requirements will not be met, and in some places, will become completely infeasible. Most minimum flow requirements are projected to be met in the wetter HCM scenario. Under both scenarios, the cost of meeting flow requirements varies significantly between wet and dry years

Mitigation Strategies/Management Challenges
Several strategies may help mitigate the impact of water and energy shortages on the various sectors described above. These management strategies vary, depending on

the region and the climate change scenario employed, but several perform well under both circumstances.

In California, modifying patterns of water demand may help mitigate impacts on environmental targets, including instream flow requirements for fish passage and water quality standards. It cannot, however, mitigate the effects of diminished hydropower generation. Alternatively, the DWR's classification of the water year type (i.e. critically dry, dry, below normal, above normal, or wet) defines the amount of water required to flow into the delta. This classification hinges on runoff in the current year and in the prior year. By determining delta flow requirements, the water year classification also determines allocations to other water users. Adjusting this classification scheme may lead to more efficient water management, benefiting all sectors (Vanrheenen et al., 2004). Groundwater storage can effectively dampen fluctuations in interannual variability; groundwater management (both groundwater banking and conjunctive use), therefore, will likely be important for meeting future demand (Zhu et al., 2006). Finally, tapping "backstop" water source technologies such as wastewater reuse and desalination can diminish arid urban areas' need to import water.

As described above, the high storage to runoff ratio in the Colorado River basin implies that management tactics will do little to diminish possible future shortages (Christensen et al., 2004). Demand modification, increasing agricultural-urban exchanges, and interstate collaboration will be necessary to dampen the economic and environmental impacts of basin-wide drought.

The Columbia River basin, on the other hand, has numerous options for mitigating future changes in water supplies. Shifting firm power deliveries (to earlier in the year, from summer to late winter/early spring) may help mitigate the economic impacts of diminished hydroelectric generation (Payne et al., 2004). Alternatively, water system managers may not be able to accommodate both hydroelectric generation and environmental requirements for instream flows, and will be forced to choose between spring and autumn hydroelectric power generation and spring/summer releases for salmon runs (Barnett et al., 2005); the outcome of these management decisions will undoubtedly affect both the timing and quantity of power deliveries to California.

Appendix B: Spreadsheet Data

BIOENERGY	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Agriculture, Rapeseed	360	630	360	630	Data is originally all in terms of "water use efficiency". We use the same numbers for rates of withdrawal and consumption, assuming that all applied water (for irrigation) is evapo-transpired. Original study assumes that, for the lower numbers (more efficient systems) waste byproducts and harvest residues are used to generate electricity.	Berndes, 2002 [W,C/H,L]
Agriculture, Sugarcane	133	558	133	558		Berndes, 2002 [W,C/H,L]
Agriculture, Sugar Beet	256	677	256	677		Berndes, 2002 [W,C/H,L]
Agriculture, Corn	263	1250	263	1250		Berndes, 2002 [W,C/H,L]
Agriculture, Wheat	144	1260	144	1260		Berndes, 2002 [W,C/H,L]
Biomass-based steam plant	2.5198	2.5198	2.5198	2.5198	Assumes a 23% specified efficiency and a HHV at 20 Gj/Mg	USDOE/EPRI, 1997 and Berndes, 2001 [W,C/H,L]
Improved biomass-based steam plant	1.7999	1.7999	1.7999	1.7999	Assumes a 34% specified efficiency and a HHV of 20 GJ/Mg	USDOE/EPRI, 1997 and Berndes, 2001 [W,C/H,L]
Gasification-based, combined cycle generation	0.3600	0.3600	0.3600	0.3600	Includes boiler feed water requirements but NOT wet scrubbing. Steam from the steam cycle is injected into the gasifier Asumes a specified efficiency of 36% and a HHV of 20 GJ/Mg.	USDOE/EPRI, 1997 and Berndes, 2002 [W,C/H,L]
Quench feed water for wet scrubbing of syngas (exiting gasifier)	0.1080	3.2400			For methanol. Hydrogen values are much higher.	Katofsky, 1993 and Berndes, 2002 [W,C/H,L]

BIOGAS	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Simple Cycle	0.084	0.084	0.084	0.084	Assumes a 500 MW plant. Analysis assumes that water requirements for landfill gas facilities are comparable to those for conventional natural gas facilities. All data are taken from conventional natural gas facilities.	Maulbetsch 2006, EPRI, CATF et al. 2003
Combined cycle, wet cooling	0.871	0.871	0.681	0.681		
Combined cycle, dry cooling	0.151	0.151	0	0		
Combined cycle, once-thru cooling	9.084	75.7	0.379	0.379		
Steam turbine, once-thru cooling	75.7	189.3	1.136	1.136		
Steam turbine, wet cooling	1.136	3.028	0.908	2.422		
Steam turbine, dry cooling	0.151	0.151	0	0		
Steam turbine, pond cooling	1.136	2.271	1.136	1.817		
Mining, combined cycle conversion technology	0	0	0	0	Unlike traditional natural gas, we assume no processing water needs (because landfill gas facilities often produce additional water by drying the captured gas). The processing water needed to produce energy from conventional natural gas is used in the pumping process.	
Transportation, combined cycle conversion technology	0	0	0	0	We assume no transportation costs, as energy is typically produced on-site (with landfill gas generation).	
Other	0	0	0	0		
Inlet fogging (additional option)	0.473	1	0.473	1		Maulbetsch 2006

COAL	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Surface Mining	0.01	0.49	0.01	0.05	Choose consumption higher value if revegetating 6150 kWh/ton of coal mined	[CH] (Gleick 1994) [CL] Set to Match WL [WL]Calculation based on (Gleick 1994) and NMA conversion [WH] Coal Text Book
Underground Mining	0.45	0.45	0.03	0.21		[C](Gleick 1994) [WL]Calculation based on (Gleick 1994) and NMA conversion [WH] Coal Text Book
Coal Washing	0.01	0.02	0.00	0.00	80% of eastern and interior coal is washed	[W] (Gleick 1994) from (Chan et al. 2006)
Pulverized Slurry Line	0.03	0.90	0.03	0.90		[CH](Gleick 1994) from (Chan et al. 2006) [WL]Coal Textbook [WH]Set to match CH [CL]Set to match WL
Log Slurry Line	0.01	0.27	0.01	0.27	Saves up to 70% water of traditional slurry.	[W] & [C] (Liu 2002)
IGCC (Gasification)	0.18	0.24	0.09	0.13	500 MW plant	[W] & [C] (Klett 2005)
IGCC Makeup Water (ex. Cooling)	0.15	0.39				[W] & [C] (Klett 2005)
IGCC Process Losses			0.09	0.13		[W] & [C] (Klett 2005)
IGCC Flue Gas Water Losses			0.29	0.40		[W] & [C] (Klett 2005)
IGCC Wet Cooling	2.30	2.79	2.30	2.79		[W] & [C] (Klett 2005)
IGCC Pond Cooling	0.74	1.48	0.74	1.18		[W] & [C] (Klett 2005)
PC Combustion	0.14	0.16	0.00	0.00	600MW pulverized coal plant.	[W] (Ziemkiewicz) [C]Hypothesis bc I can't find numbers
PC Makeup Water (ex. Cooling)	0.01	0.02				

PC Process Losses			0.03	0.03		
PC Flue Gas Water Losses			0.36	0.41		
PC Flue Gas Desulfurization	0.24	0.40	0.24	0.40		
PC Wet Cooling	3.71	4.16	3.71	3.71	Numbers are thermoelectic averages	[CH] (Feeley et al. 2005) [CL] (EPRI 2002) [WH] (Feeley et al. 2005) [WL] (EPRI 2002)
PC Once-Through Cooling	75.70	189.25	1.14	1.14	600MW pulverized coal plant. Uses 35% less water when paired with an IGCC plant	[W] (Ziemkiewicz) [C]Hypothesis bc I can't find numbers
PC Pond Cooling	1.14	2.27	1.14	1.82	Numbers from EPRI are thermoelectric averages	[C]&[W] (EPRI 2002)
PC Hybrid Wet-Dry Cooling	0.38	3.63	0.36	3.33	Results in about 50% less water consumption than a conventional closed-loop wet cooling system Consumption is 20-80% of recirculating wet cooling Uses 35% less water when paired with an IGCC plant	[C] (EPRI 2002)
PC Direct Dry Cooling	0.09	0.23	0.09	0.21	Dry cooling cuts consumption by 95% (Compared to wet cooling) Uses 35% less water when paired with an IGCC plant	(Queensland Govt DOE)
PC Indirect Dry Cooling	0.09	0.23	0.09	0.21	Same as direct cooling Uses 35% less water when paired with an IGCC plant	N/A

GEOTHERMAL	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Injection from external sources, water dominated system	0	3.49	0	3.49	High number reflects the only external injection program of its kind, in the Geysers	[W, C]Sass and Priest 2002, Dept of Oil, Gas, and Geothermal Resources 2005
Injection from external sources, steam dominated system	0	3.49	0	3.49	High number reflects the only external injection program of its kind, in the Geysers	[W, C]Sass and Priest 2002, Dept of Oil, Gas, and Geothermal Resources 2005
Cooling, once through	0	54	0	0.246	WL, CL from Bagnore, Italy; WH from Nesjavellir, Iceland. CH from Salton Sea Unit 6. The Iceland plant disposes of wastewater into groundwater flowing to a lake; maybe that explains the high. I believe it's like a once-through cooling system. Gleick says up to 15 m3/MWh if you need external water. The Geysers requires no external water for cooling (Gleick 1994).	[WH]Hagedoorn 2006, [CH] Adams et al. 2005 [WL]/[CL]Hagedoorn 2006
Cooling, wet recirculating (cooling towers)	0	17.03	0	17.03		[WL]/[CL]Adams et al. 2005, [WH]/[CH]Charles et al. 2006
Cooling, dry	0	0	0	0	Kagel mentions no numbers here; I am assuming the water required is negligible. If fossil plants withdraw such little water for dry cooling, I am assuming that small amount can be easily met with geothermal fluid (which we aren't counting).	[WH]/[CH]Kagel et al. 2005, USDOE 2006 [WL]/[CL]Kagel et al. 2005, USDOE 2006
FOR CALIFORNIA CASE STUDY, MORE SPECIFIC NUMBERS:						
Cooling, Imperial Valley	7.7	14.1	7.7	14.1		
Cooling, other locations in California	0	0.019	0	0.019		

HYDROELECTRIC	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Evaporative Losses, <25 MW plant	208.8	208.8	0.18	14.4	Average water withdrawal statistics for that size facility.	Gleick 1992 [W,C/H,L]
Evaporative Losses, >25 MW plant	162	162.0	0.036	2.520		Gleick 1992 [W,C/H,L]

Hydroelectric Power Production Method					
	Withdrawal Water Requirement (m3/MWh)		Consumptive Water Requirement (m3/MWh)		
	Low	High	Low	High	
Reservoir and Dam, < 25 MW capacity - Dam Height < Gross Static Head	208.8	208.8	0.18	82.7	
Reservoir and Dam, < 25 MW capacity - Dam Height > Gross Static Head	208.8	208.8	1.94	209	
Reservoir and Dam, > 25 MW capacity - Dam Height < Gross Static Head	162.0	162.0	0.036	122	
Reservoir and Dam, > 25 MW capacity - Dam Height > Gross Static Head	162.0	162.0	3.6	162	
"Run of River" Facility	0	0	0	0	Assumes that "run of river" facilities do not impound water, increasing rates of evaporation
Facilities in aqueducts	0	0	0	0	Assumes that these facilities do not increase rates of evaporation above existing rates.

NATURAL GAS	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Assumptions	Source
Simple Cycle	0.084	0.084	0.084	0.084	Assumes a 500 MW plant	Maulbetsch 2006, EPRI, CATF et al. 2003
Combined cycle, wet cooling	0.871	0.871	0.681	0.681		
Combined cycle, dry cooling	0.151	0.151	0.000	0.000		
Combined cycle, once-thru cooling	9.084	75.700	0.379	0.379		
Steam turbine, once-thru cooling	75.700	189.251	1.136	1.136		
Steam turbine, wet cooling	1.136	3.028	0.908	2.422		
Steam turbine, dry cooling	0.151	0.151	0.000	0.000		
Steam turbine, pond cooling	1.136	2.271	1.136	1.817		
Inlet fogging (additional option)	0.473	0.606	0.473	0.606		Maulbetsch 2006
Mining, combined cycle conversion technology	0.036	0.036	0.036	0.036	Assumes a conversion efficiency of 60% for combined cycle plants	
Mining, Simple cycle conversion technology	0.060	0.060	0.060	0.060	Assumes a conversion efficiency of 36% (from thermal to electric Joules), source - Gleick (1994)	
Transportation, combined cycle conversion technology	0.018	0.018	0.018	0.018	Assumes a conversion efficiency of 60% for combined cycle plants	
Transportation, simple cycle conversion technology	0.030	0.030	0.030	0.030	Assumes a conversion efficiency of 36% (from thermal to electric Joules), source - Gleick (1994)	
Other (hotel load)	0.000	0.360	0.000	0.360	Gleick says 0.36, but I use 0 in other places to avoid mismatching sources.	

NUCLEAR		Withdrawal m^3/MWh		Consumption m^3/MWh			
Item		Low	High	Low	High	Notes/Assumptions	Sources
Surface Uranium Mining		0.2323	0.2323	0	0	only for surface mining	[W] & [C]: Gleick 1993
Underground Uranium Mining		0.0023	0.0023	0	0	only for underground mining	[W] & [C]: Gleick 1993
Processing		0.7548	0.9058	0.4522	0.5365	processing includes: milling, conversion, enrichment, fuel fabrication, fuel reprocessing	[W] & [C]: Gleick 1993
BWR	once-thru cooling	94.6253	227.101	0.3785	5.0350	for BWR assuming once-through cooling	[W]: EPRI 2002; [C/L]: Hoffman et al. 2004; [C/H] Pace University Environmental Law Center 1990;
BWR	natural draft wet cooling tower	3.0280	5.6775	1.5140	5.6775		[W/L]:EPRI 2002; [W/H]:Hoffman et al. 2004; [C/H]:EPRI 2002; [C/L]: Hoffman et al. 2004
BWR	closed cycle cooling pond, lake, or reservoir	2.7252	4.1635	2.7252	2.7252		[W] & [C]: EPRI 2002
PWR	once-thru cooling	94.6253	227.101	0.3785	1.5140		[W] EPRI 2002; [C/L]: Hoffman et al. 2004; [C/H]: EPRI 2002
PWR	natural draft wet cooling tower	3.02801	5.67752	1.5140	5.6775		[W/L]:EPRI 2002; [W/H]:Hoffman et al. 2004; [C/H]:EPRI 2002; [C/L]: Hoffman et al. 2004

	closed cycle cooling pond, lake, or reservoir	2.7252	4.16351	2.7252	3.2330		[W] EPRI 2002; [C/L]: EPRI 2002; [C/H]: Pace University Environmental Law Center 1990

OIL	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Oil Shale Mining - Direct Aboveground Retorting (AGR)	0.028	0.045	0.028	0.045	All calculations assume one barrel of crude oil (42 gallons) has an energy capacity of 1700 kWh. Assumes a 50,000 bbl/day facility. The cited reference describes all water used as "consumed water" and does not distinguish from "withdrawn water". The quality of the water may, indeed, mean that it is effectively consumed; however, there may be some opportunity for reclaiming water. We do not tackle that question. "Other" uses include water for disposal and revegetation, dust control during extraction, plant utilities, and on-site power needs.	Emerging Issues for Fossil Energy and Water, 2006 [W,C/H,L]
Oil Shale Mining - Indirect AGR	0.035	0.047	0.035	0.047		
Oil Shale Mining - Modified In-situ (MIS)/AGR	0.013	0.014	0.013	0.014		
Oil Shale Mining - Modified In-situ (MIS)	0.020	0.020	0.020	0.020		
Oil Shale Processing - Direct Aboveground Retorting (AGR)	0.088	0.111	0.088	0.111		
Oil Shale Processing - Indirect AGR	0.137	0.201	0.137	0.201		
Oil Shale Processing - Modified In-situ (MIS)/AGR	0.121	0.145	0.121	0.145		
Oil Shale Processing - Modified In-situ (MIS)	0.100	0.100	0.100	0.100		
Oil Shale (Other) - Direct Aboveground Retorting (AGR)	0.077	0.121	0.077	0.121		
Oil Shale (Other) - Indirect AGR	0.181	0.276	0.181	0.276		
Oil Shale (Other) - Modified In-situ (MIS)/AGR	0.072	0.094	0.072	0.094		
Oil Shale (Other) - Modified In-situ (MIS)	0.077	0.077	0.077	0.077		

Combined cycle, once-thru cooling	9.084	75.700	0.379	0.379	Analysis assumes that oil cooling is the same as natural gas cooling.	EPRI, CATF et al. 2003
Combined cycle, wet cooling	0.871	0.871	0.681	0.681		
Combined cycle, dry cooling	0.151	0.151	0.000	0.000		
Steam turbine, once-thru cooling	75.700	189.251	1.136	1.136		
Steam turbine, wet cooling	1.136	3.028	0.908	2.422		
Steam turbine, dry cooling	0.151	0.151	0.000	0.000		
Steam turbine, pond cooling	1.136	2.271	1.136	1.817		
Drilling	0.01	32.04	0.01	32.04		Gleick 1994

Refining	0.09	0.43	0.09	0.43		Gleick 1994
Other (hotel load)	0.25	0.25	0.25	0.25		Gleick 1994

SOLAR	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Parabolic Trough Plant - wet cooling	2.80	2.87	2.80	2.87	Withdrawn is equivilant to consumed when withdrawn numbers are not available.	Stoddard, et al.2006 [W,C/L]; The Last Straw [W,C/H]
Parabolic Dish-Engine - dry cooling	0	0	0	0	No cooling required.	Stoddard, et al.2006 [W,C/H,L]
Power Tower - wet cooling	2.40	2.80	2.40	2.80		Solar Paces 2007 [W,C/L]; Stoddard et al. 2006 [W,C/H]
PV - Distributed (Rooftop) Systems	0	0	0	0	No cooling required.	
PV - Large Centralized Plants	0	0	0	0	No cooling required.	The Last Straw; Stoddard et al. [W,C/H,L]
PV - Concentrating PV Systems	0	0	0	0	No cooling required.	
Parabolic Trough Plant washing	0.14	0.27	0.14	0.27	High number found by subtracting the cooling water amt from the cooling and process water amt listed for this technology in the Last Straw	Stoddard, et al.2006 [W,C/L], Direct Communication, Mike Roverson, Kramer Junction [W,C/L], Last Straw [W,C/H]
Parabolic Dish-Engine washing	0	0	0	0		Stoddard, et al.2006 [W,C/H,L]
Power Tower washing	0	0.14	0	0.14	Assumed to be roughly equal to washing needs of a Parabolic Trough plant as both have large mirror fields.	
PV - Distributed (Rooftop) Systems washing	0	0.11	0	0.11	Number for PV washing requirments used for both large plants and distributed gen (rooftop).	The Last Straw; AWEA Website 2006

PV - Large Centralized Plant washing	0	0.11	0	0.11	Number for PV washing requirments used for both large plants and distributed gen (rooftop).	AWEA Website 2006
PV - Concentrating PV Systems washing	0	0	0	0		Stoddard, et al.2006

WIND	Withdrawal m^3/MWh		Consumption m^3/MWh			
Item	Low	High	Low	High	Notes/Assumptions	Sources
Cleaning medium sized wind farms	0	0.00379	0	0.00379	If the wind turbines are never cleaned, then the withdrawal and consumption equals zero	[W/L]: van Dam; [W/H]: AWEA 2006; [C/L]: van Dam; [C/H]: AWEA 2006
Cleaning large sized wind farms	0	0.00247	0	0.00247	If the wind turbines are never cleaned, then the withdrawal and consumption equals zero Wind farms can operate at 30% of nameplate capacity If washed, turbines are washed 3 times/year Each turbine uses 40 gallons per washing	[W/L]: van Dam; [W/H]: J. Harris 2006; [C/L]: van Dam; [C/H]: J. Harris 2006

Appendix C: Calculations

Bioenergy
All calculations for producing bioenergy from dedicated energy crops are from Berndes (2001) and Berndes (2002). The only calculation is the conversion from Million grams per GJ to m^3/MWh:

$1\ Mg = 1\ m^3$
$1\ GJ = 0.2778\ MWh$

$$\frac{Mg}{GJ} \times \frac{1m^3}{Mg} \times \frac{1GJ}{0.2778\,MWh} \Rightarrow \frac{m^3}{MWh}$$

Berndes (2002) and Berndes (2001) note several figures for water use in typical power plant cooling facilities. Their analysis makes several assumptions about heat capacity and conversion efficiency (from thermal energy to electric energy). These assumptions are noted; we did not make any further assumptions or conversions. The calculation for converting their figures (in units of Mg/GJ) to m^3/MWh are as shown above.

Geothermal, Oil, Natural Gas
All figures of water used for geothermal electricity production are from these sources:

- Sass and Priest (2002)
- Dept of Oil, Gas, and Geothermal Resources (2005)
- Hagedoorn (2006)
- Adams et al. (2005)
- Charles et al. (2006)
- Kagel et al. (2005)
- USDOE (2006)

All figures of water used for electricity production from oil and natural gas plants are from these sources:

- Maulbetsch (2006)
- EPRI
- Baum et al. (2003)
- Gleick (1994)

All figures were converted into m^3/MWh figures using the conversion factors of Appendix D. If separate water volumes and watt-hour figures were given, they were converted and divided to form a m^3/MWh figure.

For geothermal calculations, if only a power figure (MW or kW figure) was given, it was assumed that geothermal plants operate at 90 percent capacity (Kagel et al., 2005). The power figure was then multiplied by 7884 hours (90 percent of the hours in one year) to form a MWh figure to be used in the denominator of the m^3/MWh figure.

Some of the figures from Gleick (1994) used MWh(t) in the denominator. In this case, it was assumed that simple cycle plants operate at 36 percent capacity (Bingham & Lewandowski, 2003); (Gleick, 1994), and that combined cycle plants operate at 60 percent capacity (Oman, 1996). The MWh(t) figures were multiplied by these percentages to be converted to MWh(e) figures, which are the standard MWh figures used in the denominators of our workbook.

Nuclear

Uranium Processing - Water Requirements (based on Gleick 1993 data)

	Withdrawn		Consumed	
	low	high	low	High
	m^3/10^12 J(th)		m^3/10^12 J(th)	
Uranium milling	8	10	8	10
Uranium conversion	4	4	1.2	1.2
Uranium enrichment: gaseous diffusion		13	10	15
Uranium enrichment: gas centrifuge	2			
Fuel fabrication	1	1		
Nuclear fuel reprocessing	50	50	20	20
Total processing	65	78	39.2	46.2

31% system efficiency of converting thermal energy to electrical energy

	Withdrawn		Consumed	
	low	high	low	High
Total Processing (m^3/10^12 J)	209.68	251.61	126.45	149.03
TOTAL PROCESSING (m^3/MWh)	**0.7548**	**0.9058**	**0.4522**	**0.5365**

Oil Shale

Table 1.

Total Water Use (barrels of water per barrel of oil)						
Direct AGR		Indirect AGR		MIS/AGR		MIS
Low	High	Low	High	Low	High	Average
2.3	2.7	4.2	5	2.4	2.5	2.1

Table 2.

	Percentage of Total Water Used						
	Direct AGR		Indirect AGR		MIS/AGR		MIS
Subprocesses	Low	High	Low	High	Low	High	Average
Mining and Handling	13	18	9	10	6	6	10
Power Generation	0	10	8	12	0	0	0
Retorting and Upgrading	41	44	35	43	54	62	51
Disposal and Revegetation	26	26	33	40	19	26	23
Municipal	10	12	5	7	13	14	16

Calculation: Multiply the total water used for each process by the percent of water used in each subprocess (Table 1 * Table 2 / 100 = Table 3).

Table 3.

	Use by component (barrel of water/barrel of oil)						
	Direct AGR		Indirect AGR		MIS/AGR		MIS
Subprocesses	Low	High	Low	High	Low	High	Average
Mining and Handling	0.299	0.486	0.378	0.5	0.144	0.15	0.21
Power Generation	0	0.27	0.336	0.6	0	0	0
Retorting and Upgrading	0.943	1.188	1.47	2.15	1.296	1.55	1.071
Disposal and Revegetation	0.598	0.702	1.386	2	0.456	0.65	0.483
Municipal	0.23	0.324	0.21	0.35	0.312	0.35	0.336

Calculation: Convert barrels of water/barrels of oil to m^3 water/kWh.
= Table 3 * 42 (gallons water/barrel water) *1/264.2 (m^3 water/gallons water) * 1/1700 (barrel of oil/kWh)

This calculation assumes that one barrel of crude oil (42 gallons) has an energy capacity of 1700 kWh.

Table 4.

Subprocesses	Water Use by component (m^3/kWh)						
	Direct AGR		**Indirect AGR**		**MIS/AGR**		**MIS**
	Low	High	Low	High	Low	High	Average
Mining and Handling	2.80E-05	4.54E-05	3.53E-05	4.68E-05	1.35E-05	1.4E-05	1.96E-05
Power Generation	0	2.52E-05	3.14E-05	5.61E-05	0	0	0
Retorting and Upgrading	8.82E-05	1.11E-04	1.37E-04	2.01E-04	1.21E-04	1.45E-04	1.00E-04
Disposal and Revegetation	5.59E-05	6.56E-05	1.30E-04	1.87E-04	4.26E-05	6.08E-05	4.52E-05
Municipal	2.15E-05	3.03E-05	1.96E-05	3.27E-05	2.92E-05	3.27E-05	3.14E-05

Final Calculation: to convert to m^3/MWh, multiply by 1000.

Note: These calculations are only for converting the oil shale to crude oil, *not* for further processing or generating electricity.

Wind Power

Assumptions:

1.) 30% generation of nameplate capacity
2.) 40 gallons per turbine per washing (J. Harris)
3.) 3 turbine washings per year (J. Harris)
4.) Sample 43.4MW plant in Palm Springs, CA is representative of wind farms

$$0.3 \times 43.4\ \text{MW} \times \frac{365.25\ \text{days}}{\text{year}} \times \frac{24\ \text{hr}}{1\ \text{day}} = \frac{114133.32\ \text{MWh}}{\text{year}}$$

$$62\ \text{turbines} \times \frac{40\ \text{gallon}}{1\ \text{turbine washing}} \times \frac{3\ \text{turbine washings}}{\text{year}} = \frac{7440\ \text{gallons}}{\text{year}}$$

$$\frac{7440\ \text{gallons}}{\text{year}} \times \frac{1\ \text{year}}{114133.32\ \text{MWh}} = \frac{0.06519\ \text{gallons}}{\text{MWh}} = \mathbf{\frac{0.000247\ m^3}{MWh}}$$

Appendix D: Conversions

Conversion of Units

Energy

1	kWh	=	3.60E+06	Joules
1	J	=	2.78E-07	kWh
1	GJ	=	277.8	kWh
1.00E+12	J	=	2.78E+05	kWh
1.00E+18	J	=	2.78E+11	kWh
5.80E+06	Btu	=	1 barrel of crude oil	
1.70E+03	kWh	=	1 barrel of crude oil	

Volume

1	m^3	=	1000	liters
1	m^3	=	264.2	gallons (U.S.)
1	m^3	=	35.31	ft^3
1234	m^3	=	1	acre-foot
1	km^3	=	1E+09	m^3
1	m^3	=	1	Mg (million grams)

Volume/Energy Unit Conversions

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} = \frac{0.001\ \text{m^3}}{\text{kWh}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} \times \frac{264.2\ \text{gal}}{1\ \text{m^3}} = 0.2642\ \frac{\text{gal}}{\text{kWh}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{264.2\ \text{gal}}{1\ \text{m^3}} = \frac{264.2\ \text{gal}}{\text{MWh}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} \times \frac{1000\ \text{liters}}{1\ \text{m^3}} = 1\ \frac{\text{liter}}{\text{kWh}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{35.31\ \text{ft^3}}{1\ \text{m^3}} \times \frac{1\ \text{hr}}{60\ \text{min}} \times \frac{1\ \text{min}}{60\ \text{sec}} = 0.0098\ \frac{\text{ft^3}}{\text{MWs}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{264.2\ \text{gal}}{1\ \text{m^3}} \times \frac{24\ \text{hours}}{1\ \text{day}} = 6340.8\ \frac{\text{gal}}{\text{MWd}}$$

$$\frac{1\ \text{m^3}}{\text{MWh}} \times \frac{1\ \text{ac-ft}}{1234\ \text{m^3}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} = 8.10\text{E-07}\ \frac{\text{ac-ft}}{\text{kWh}}$$

Appendix D: Conversions (continued)

Volume/Energy Conversions (Continued)

$$\frac{1\ \text{m}^3}{\text{MWh}} \times \frac{2.78\text{E-}07\ \text{kWh}}{1\ \text{J}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} = 2.78\text{E-}10\ \frac{\text{m}^3}{\text{J}}$$

$$\frac{1\ \text{m}^3}{\text{MWh}} \times \frac{1\ \text{Mgal}}{1\ \text{m}^3} \times \frac{2778\ \text{kWh}}{1\ \text{GJ}} \times \frac{1\ \text{MWh}}{1000\ \text{kWh}} = 2.778\ \frac{\text{Mgal}}{\text{GJ}}$$

$$\frac{1\ \text{m}^3}{1.0\text{E+}12\ \text{J}} \times \frac{1\ \text{J}}{2.78\text{E-}07\ \text{kWh}} \times \frac{1000\ \text{kWh}}{1\ \text{MWh}} = 3.60\text{E-}03\ \frac{\text{m}^3}{\text{MWh}}$$

$$\frac{1\ \text{km}^3}{1.0\text{E+}18\ \text{J}} \times \frac{1.00\text{E+}09\ \text{m}^3}{1\ \text{km}^3} \times \frac{1\ \text{J}}{2.78\text{E-}07\ \text{kWh}} \times \frac{1000\ \text{kWh}}{1\ \text{MWh}} = 3.5971\ \frac{\text{m}^3}{\text{MWh}}$$

Appendix E: Users' Guide for the Energy-Water Calculator

Introduction

The Energy-Water Calculator is an interactive web-based tool that provides an estimate of the water amount necessary to support a specific energy generation portfolio. Electricity generation portfolios, comprised of varying amounts of MW (megawatts) per energy technology, are entered as actual generation per facility (not nameplate capacity) over whatever timeframe the user desires (MW per hour, MW per year, etc.). An unlimited number of inputs for different facilities within a given portfolio or service area can be added, which appear on separate lines; once all generation amounts and facility details (such as cooling type) have been entered the user clicks the "Go" button on the last data line entered and the tool will calculate high and low estimates for the required amount of withdrawn and consumed water to run the user's portfolio.

The workbook that contains the data to support this tool (amount of water in m^3/MWh) is organized by primary energy source, specific conversion technology used, and the different steps in the generation process which require water. Each spreadsheet in the workbook totals across the different water input steps for each type of generation and displays in the farthest right hand column the amount of water required for each combination of primary energy type and specific conversion technology used. This "total" column displays both consumptive water use and total water withdrawal required. Additionally it gives a low and high estimate for each of these categories.

Step-by-Step Guide

This web tool is available at **http://fiesta.bren.ucsb.edu/~energywater/**.

To use this tool:

1. Enter the actual generation in MW (over whatever time frame you choose – daily, monthly, or yearly time frames for example) for the first facility in your service area or jurisdiction.
2. Select the fuel type. Choose from Bioenergy, Coal, Geothermal, Hydroelectric, Natural Gas, Nuclear Power, Oil, Solar, or Wind. The calculator's menus are responsive and will give you a different set of choices depending on what primary energy type you select.
3. Next, in the box to the right, select the type of power. For example, if solar power is specified you need to choose between Solar Thermal and Photovoltaic technologies.
4. Again, moving to the right, you need to specify the type of system for the type of primary energy previously selected. Continuing with the solar power

example, Solar Thermal generation facilities must be further classified as parabolic trough, dish-engine, or power tower systems.

5. Wrapping around and beginning again on the left, three more input boxes exist to further specify the type of generation technologies employed in the facility of interest to convert the selected primary energy source (or fuel) to electric energy.
6. Continue adding input lines and entering the actual generation and specific facility type or conversion technology for each generation facility in your portfolio.
7. When all electricity generation facilities in your portfolio have been entered, click the go button on the last line you have entered. The tool will then calculate the low and high estimates of water withdrawals required to generate the amount of energy specified in the manner specified by you and the high and low estimates of the amount of the withdrawn water that is consumed in the power generation process. This information can be found at the very top of the page; you may need to scroll back up to see this output.

For you convenience, the tool also calculated high and low estimates for water withdrawn and consumed for each facility you have entered. These estimates can be found between each line of input data. The tool also calculates the average withdrawal and consumption estimates for the whole portfolio and for each facility entered. It is assumed that you as the user will better know if a facility in your portfolio tends toward the higher or lower water use estimates based on the local conditions of a facility (for example, in very hot places, water losses due to evaporation from cooling towers may be greater than a similar facility in a cooler area may demonstrate.

Q&A

How do I clear the page and start again?

- **Refresh** the page in your browser to clear the page and start again OR click on **Reset All** at the top of the page.

How do I change a specific input line without clearing the whole page?

- Click on the **Reset button** at the end of each line.

How can I see the underlying spreadsheets that the tool is based on?

- click on the link provided in the navigation bar off the web tool's home page at **http://fiesta.bren.ucsb.edu/~energywater/.**

Can I get a copy of this workbook?

- Yes. Feel free to download it. You can then change or up date it and use it to best meet you energy-water planning needs!

Something isn't working. Who can I contact?

- please contact the individual listed on the Energy-Water Calculator homepage.

Other Information

The data workbook which forms the foundation for this calculator tool is available for advanced users convenience and background information. While the workbook cannot be altered, it is freely available for downloading and altering or updating. Both the workbook and a complete reference list will be linked from the URL listed above.

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