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The Impact of Traditional and Alternative Energy Production on Water Resources:

Assessment and Adaptation Studies

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ABSTRACT

Water, fuel, and energy issues are intricately related and cannot be addressed in isolation. With increasing population, increasing energy demand, continued migration towards and population growth within water stressed regions of the U.S., and with the continuing impacts of climate change on water availability, scarcity of freshwater will be an issue of paramount importance. Finding alternative water resources to replace freshwater demand for thermoelectric power generation and/or reducing water usage in cooling applications is inevitable and urgent. Biofuel production for transportation also has significant water requirements, especially at the cultivation stage. The assessment and adaptation studies described here investigate and integrate the current knowledge base of water usage in energy production industries. This report documents the research results on the generation of electricity and the emerging production of biofuels by assessing major trends in thermoelectric power generation and biofuels and investigating future water availability and water allocation for these energy production and energy transformation processes. Its primary focus is on coal-fired and natural gas-fired electric power plants, the production of corn-starch-based ethanol and cellulosic biofuels, the production of biodiesel, the impacts of all of these processes on water resources, as well as technologies available to adapt these processes to reduce their impact, particularly in water-stressed regions of the United States. The report includes detailed analyses and water resource adaptation strategies for sustainable energy production, including a case study focusing on the water-stressed southwestern U.S. using Las Vegas, Nevada as a specific example.

PREFACE

Water is essential to life. Uneven global distribution of population and water resources has resulted in more than 1.1 billion people world-wide lacking access to clean drinking water and 2.6 billion people living in regions with inadequate freshwater treatment. Today freshwater is being consumed at an alarming rate and is almost doubling every 20 years. Global climate change exacerbates this already stressed situation. Water availability is not only a problem for developing countries, but also one facing developed nations now saddled with an aging water infrastructure. Throughout history, civilizations have found innovative solutions to meet their water resource needs and responded to evolving social and environmental conditions. This spirit of adaptation continues to this date.

Today, one of the most complex challenges facing our nation revolves around the water-energy nexus. The linkages between water use, climate change and the production, transformation and use of energy require an interdisciplinary, holistic approach to future water management, both in quality and quantity. The energy sector is one of our nation's largest water users of water. Large quantities of water are withdrawn and consumed every year to provide electricity and liquid fuels and these amounts are expected to continue to grow unless steps are taken to establish more efficient and renewable methods of generation and production. Environmental conditions in the U.S. are becoming increasingly more important in making decisions about the location, size, and type of energy production necessary to supply the vast amounts of energy required to power our economy. Furthermore, the energy sector is in transition. The U.S. is transitioning towards less carbon-intensive electric power generation in order to reduce CO_2 emissions and their contribution to climate change. Biofuels are increasingly being used in the U.S. in response to policies to reduce petroleum imports. All of these factors also have important consequences with respect to water withdrawal and consumption, especially in water stressed regions.

This report presents a preliminary assessment of water used in two segments of energy production: electric power generation and the production of biofuels for transportation. It is structured to address science and engineering questions pertinent to adaptation and to support technical managers and other stakeholders facing the enormous complexity of climate adaptation. This objective is accomplished by structuring individual chapters around stand-alone, but interrelated, science and engineering subjects. After discussing the "big" picture of adaptation needs, the report provides in-depth analyses of water use and adaptation strategies and emerging technologies. As an initial first step, it is hoped that this effort marks a beginning of the long march toward the goal of sustainable infrastructure adaptation to changing climate and socioeconomic conditions.

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ABBREVIATION AND ACRONYMS

7Q10	Seven-day average of 10 year return flows
ABMet	Advanced biological metals (removal process)
ABRWTF	American bottoms regional wastewater treatment facility
ACC	Air-cooled condenser
AEO	Annual energy outlook
AFEX	Ammonia fiber expansion
Al	Aluminum
Al_2O_3	Aluminum oxide
A-O	Atmospheric-ocean
AMO	Atlantic multidecadal oscillation
ANL	Argonne National Laboratory
AO	Arctic oscillation
AOGCM	Atmospheric-ocean general circulation model
AR	Arkansas
As	Arsenic
B5	5% biodiesel blended with 95% petroleum diesel
B20	20% biodiesel blended with 80% petroleum diesel
BIT	Bituminous and anthracite coal
BFD	Block flow diagram
BOD	Biological oxygen demand
BTU	British thermal unit
ºC	Degrees Celsius
Ca	Calcium
CA	California
CA-MC	Cellular automata Markov chain
CAA	Clean Air Act
$CaCO_3$	Calcium carbonate
CAFE	Corporate average fuel economy
CAN	Central North America
CaO	Lime (calcium oxide)
$Ca(OH)_2$	Slaked lime (calcium hydroxide)
CapWa	Water capture
$CaSO_3$	Calcium sulfite
$CaSO_4 \bullet 2H_2O$	Gypsum
CCF	Recirculation cooling using freshwater
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCS	Recirculation cooling using saline water
Cd	Cadmium
CMD	Coal mine drainage
CMIP5	Coupled model intercomparison project phase 5
CMW	Concentrated municipal wastewater
Co	Cobalt
CO	Colorado or carbon monoxide

CO_2	Carbondioxide
CO_2+H_2	Syn gas
COD	Chemical oxygen demand
Cr	Chromium
CSP	Concentrated solar power
CT	Connecticut
Cu	Copper
CWA	Clean Water Act
CWTS	Constructed wetlands treatment system
DDGS	Dry distiller grains with solubles
DJF	Winter months (December, January, February)
DOE	Department of Energy
DS	Dissolved solids
E10	10% ethanol blended with 90% gasoline
E15	15% ethanol blended with 85% gasoline
E85	85% ethanol blended with 15% gasoline
EGS	Enhanced geothermal systems
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
ENA	Eastern North America
ENSO	El-Niño southern oscillation
EPRI	Electric Power Research Institute
EPS	Extracellular polymeric substances
ESP	Electrostatic precipitator
ESRI	Environmental Systems Research Institute
ºF	Degrees Fahrenheit
F_{BioD}	Percentage conversion from soy oil to biodiesel
F-T	Fisher-Troche (process)
FAME	Fatty acid methyl ester
Fe	Iron
FERC	Federal Energy Regulatory Commission
FFA	Free fatty acid
FGD	Flue gas desulfurization
FL	Florida
F_{soy}	Percentage oil content of soybeans
F_{use}	Percentage of soy oil produced used for biodiesel production
GA	Georgia
g	Gram
gal	Gallons
gal/gal	Gallons of water per gallon of (biofuel)
GAO	Government Accountability Office
GCM	General circulation model
GE	General Electric
GHG	Greenhouse gas
GJ	Giga joules
GTU	Gas Technology Institute

GW	Giga-watt
GWe	Giga-watt electrical
H	Hydrogen
H_2O	Water
H_2SO_4	Sulfuric acid
HERO	High efficiency reverse osmosis
Hg	Mercury
hr	Hour
HRSG	Heat recovery steam generator
IA	Iowa
ICS	Intentional created surplus
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
ITS	Ice thermal storage
JJA	Summer months (June, July, August)
K	Potassium
Kg	Kilogram
KJ	Kilojoules
KOH	Potassium hydroxide
KS	Kansas
kWh	Kilowatt-hours
L	Liter
LA	Louisiana
lb/hr	Pounds per hour
LCA	Life cycle assessment
LHV	Lower Heating value
LIG	Lignite coal
LMR	Lower Mississippi River or Little Miami River
LMRB	Lower Mississippi River Basin
LONE	Lower Mississippi – Ohio River Valley – New England Region
LVR	Lower Virgin River
LVRB	Lower Virgin River Basin
m^2	Square meter
m^3/sec	Cubic meters per second
m^3/hr	Cubic meters per hour
MA	Massachusetts
MAM	Spring months (March, April, May)
MASS2	Modular aquatic simulation system 2-dimensional
MCE	Multi-criterion evaluation
MCL	Maximum contaminant level
MD	Maryland
mg/L	Milligrams per liter
μg/L	Microgram per liter
MgO	Magnesium oxide
MGPY	Million gallons per year
Mgy	Million gallons per year

MIW	Mining impacted water
MJ	Megajoules
MMBtu/hr	One million BTUs
MMD	Multi-modal dataset
MMgpy	Million gallons per year
Mn	Manganese
MW	Megawatts
MWe	Megawatt electrical
MWh	Megawatt-hours
N_2	Nitrogen
N_{1j}	Normalized irrigation water used in soybean growth stage for each state (MGPY)
N_{2j}	Normalized water use during soybean oil processing stage for each state (MGPY)
N_{3j}	Normalized water use in the biodiesel production stage for each individual stage (MGPY)
N_{tot}	Normalized total water consumption for all stages for each individual state (MGPY)
Na	Sodium
NAO	North Atlantic Oscillation
$NaOCH_3$	Sodium methoxide
NaOH	Sodium hydroxide
NAP	National Academies Press
NBAA	National Business Aviation Association
NBB	National Biodiesel Board
NCERC	National Corn to Ethanol Research Center
NDPES	National Pollutant Discharge Elimination System
NE	Nebraska
NEMS	National Energy Modeling System
NERC	North American Electricity Reliability Council
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NH_3-N	Ammonia as nitrogen
NJ	New Jersey
NNE-SSW	North-Northeast – South-Southwest
NO	Nitrous oxide
NO_2-N	Nitrate as nitrogen
NO_3-N	Nitrite as nitrogen
NOAA	National Oceanic and Atmospheric Administration
NOPA	National Oilseed Processors Association
NOx	Generic term for all nitrous oxides
NRC	National Research Council
NREL	National Renewable Energy Laboratory
NV	Nevada
NY	New York
O_2	Oxygen

O&M	Operation and maintenance
OC/OTC	Once-through, with cooling ponds or canals
OF/OTF	Once-through, freshwater
OTS	Once-through, saline water
OH	Ohio
OK	Oklahoma
Ortho-P	Orthophosphate
OS	Once-through, saline water
Pb	Lead
PBR	Photobioreactor
PCA	Power controlling authorities
PCMDI	Program for Climate Model Diagnosis and Intercomparison
PDO	Pacific Decadal Oscillation
PNNL	Pacific Northwest National Laboratory
POTW	Publicly owned treatment works
ppb	Parts per billion
PRB	Powder River Basin
PSD	Prevention of significant deterioration
PV	Photovoltaic
R	Normalized precipitation rate of change (cm/month)
R&D	Research and development
RC	Recirculating, with cooling ponds or canals
RCM	Regional climate model
ReEDS	Regional Energy Deployment System
RF	Recirculating, with forced draft cooling towers
RFS	Renewable Fuel Standards
RFS2	Revised Renewable Fuel Standards
RI	Recirculating, with induced draft cooling towers
RIN	Renewable Identification Number
RN	Recirculating, with natural draft cooling towers
RTO	Regional Transmission Organization
SDWA	Safe Drinking Water Act
SiO_2	Silicon dioxide
SIUE	Southern Illinois University, Edwardsville
SNWA	Southwest Nevada Water Authority
SO_2	Sulfur dioxide
SO_3	Sulfite
SO_4	Sulfate
SON	Autumn months (September, October, November)
SOx	Generic term for sulfur oxides
SrO	Strontium oxide
SS	Suspended solids
SSCF	Simultaneous saccharification and co-fermentation
SST	Surface Sea Temperature
SUB	Sub-bituminous coal
TDS	Total dissolved solids

TiO_2	Titanium dioxide
TKN-N	Total Kjeldahl nitrogen as nitrogen
TMC	Transport membrane condenser
TMDL	Total Maximum Daily Load
TOC	Total organic carbon
TSS	Total suspended solids
TX	Texas
UIC	Underground injection control
UNESCO	United Nations Educational, Scientific and Cultural Organization
U.S.	United States
USB	United Soybean Board
USDA	U.S. Department of Agriculture
U.S. EPA	U.S. Environmental Protection Agency
USCCSP	U.S. Climate Change Science Program
USGS	United States Geological Survey
USHCN	U.S. Historical Climatological Network
VA	Virginia
V_T	Total volume of irrigation water for soybean cultivation in a state or region (acre-feet)
W_{1j}	Irrigation water used in soybean growth stage for each individual state (MGPY)
W_{2j}	Water use during soybean oil processing stage for each individual state (MGPY)
W_{3j}	Water use in the biodiesel production stage for each individual stage (MGPY)
W_{tot}	Total water consumption for all stages for each individual state (MGPY)
WA	Washington
WC	Waste coal
WCG	Waste coffee grounds
wESP	Wet electrostatic precipitators
WMO	World Meteorological Organization
WNA	Western North America
WY	Wyoming
Zn	Zinc

EXECUTIVE SUMMARY

Electricity and transportation are currently the two largest sources of energy demand in the United States (U.S.). According to the U.S. Energy Information Administration's Annual Energy Outlook 2014, coal was used to generate 37% of the total electricity, followed by natural gas, nuclear power and renewable energy at 30%, 19%, and 12%, respectively, in 2012. Each step in the production of fuel for energy, transportation, and electricity generation requires large amounts of water that is either withdrawn or consumed. Water consumption refers to the loss of water from a water source due to water evaporation, water use in processes or return to a different source. Water withdrawal refers to water that is taken from a particular water source without regard to the amount that is returned.

Thermoelectric generation is responsible for a significant portion of total water withdrawals in the U.S. According to the most recent data from the U.S. Geological Survey, thermoelectric power plants are responsible for approximately 40% of total freshwater withdrawals, approximately 50% of total water use, and approximately 4% of total freshwater consumption. This will stress water availability particularly in drought-prone regions of the U.S. such as in the Southwest. Biofuels from agriculture account for approximately 7% of transport fuel consumption. Agricultural irrigation for biofuel production accounts for approximately 4% of total freshwater consumption. Climate change models summarized within recent reports by the United Nations Intergovernmental Panel on Climate Change project 10% or more decreases in precipitation in southwest U.S., and changes in precipitation from snow to rain, resulting in a decrease in snow pack, and hence, seasonal stream flows. Simulations also project decreased precipitation and increased drought in Southeast U.S., and increased precipitation and flooding along the Great Lakes and Northeast U.S.

The availability of water for power generation and biomass production for biofuels will be affected by extraneous factors such as climate change, population growth and redistribution, domestic consumption, and land use. Furthermore, water availability also limits the potential of production water discharge from thermoelectric power plants into streams and rivers to prevent thermal pollution of the receiving water body. Climate change has been shown to cause precipitation variations in its intensity, frequency, seasonality, and amounts, leading to variations in surface water flow and groundwater levels, which in turn can affect energy production processes. Due to the uncertainty in climate change and the increasing demand for water for electricity and biofuels, there will be substantial competition for water in many water-stressed regions between energy, commercial, industrial and residential sectors.

Emission of greenhouse gases such as CO_2 through the combustion of coal and other fossil fuels is a leading contributor to global warming. Coal combustion is also a significant contributor to air emissions of NOx, SOx, fine particulate matter, mercury and other hazardous air pollutants. For coal to continue to drive electric power generation and economic expansion across the globe in an environmentally neutral manner, technology must continue to be developed in order to reduce coal plant emissions to near-zero levels. Natural-gas fired plants offer an alternative to using coal as a fuel source for thermoelectric generation while also providing advantages in terms of fuel costs, lower greenhouse gas emissions, potentially higher efficiency, and potentially lower volumes of water withdrawals. There is also greater accessibility and abundance of natural gas in the U.S. due to the use of hydraulic fracturing. The use of natural gas in electric power generation is expected to increase from 30% to approximately 63% of total electricity production in the U.S. by 2040.

Currently, a majority of the electricity in the U.S. is generated by combusting fossil fuels in a boiler to produce steam and using the kinetic energy of the steam to generate electricity with steam turbines. In addition to the water required to produce steam, other uses of water in power plants include the water required to condense steam after it passes through the steam turbine, water lost due to evaporation in cooling towers, water required for scrubbing flue gases to meet Clean Air Act (CAA) regulations, and water required to dispose fly ash, among others. Considering water usage is critically important in areas with significant levels of irrigation and thermoelectric power generation (especially the amount of water required to condense steam) and is especially important in areas effected by climate change. Various direct and indirect steps can be taken to minimize water use in thermoelectric power plants, including using advanced cooling technologies such as air or hybrid cooling, using supercritical or ultra-supercritical steam turbines, use of advanced power generation units such as a natural gas combined cycle (NGCC) turbine with heat recovery steam generators (HRSG), use of non-traditional sources for process and cooling waters, and use of advanced wastewater treatment technologies to treat process water and wastewater from flue gas desulfurization (FGD) units that can allow reuse of effluent in the energy generation process.

A summary of the amount of water withdrawn and the amount of water consumed during electricity generation using coal (with and without integrated gasification combined cycle (IGCC) and CO_2 capture) and natural gas (Rankine and NGCC), nuclear and concentrated solar (thermal), all with recirculating steam cooling systems are compared in Table ES1. Table ES1 also contains references to specific chapters of this report where additional details can be found regarding water use for thermoelectric generation. An interactive Adobe Flash™ based module has also been developed and validated to relate power plant emissions to power plant ratings and coal characteristics for current and future coal-fired electric generation technologies as well as provide estimates of water usage and price of electricity production.

Table ES1 Water-intensity on a withdrawal and consumptive basis for thermoelectric generation using different sources of energy and using recirculating cooling systems

System	Water withdrawals		Water consumption		Chapter
	gal/MWh*	10^{-4} m^3/MJ**	gal/MWh	10^{-4} m^3/MJ	
Coal	500-1200	5.3-12.6	201-1189	5.0-11.6	4 & 9
IGCC	161-605	1.7-6.4	34-449	0.4-4.7	9
Natural Gas (Rankine/steam turbine only)	950-1460	10.0-15.4	662-1170	7.0-12.3	5
NGCC	150-283	1.6-3.0	130-300	1.4-3.2	5
Nuclear	793-2589	8.3-27.2	581-898	6.1-9.4	9
Concentrated Solar Thermoelectric	740-1110	7.8-11.7	555-1902	5.8-20.0	9

Note: Please refer to the individual chapters for information on sources of water use data.
* English units of gallons per megawatt-hour
** SI units of cubic meter per mega-joule

According to the U.S. Energy Information Administration's Annual Energy Outlook 2014, petroleum-derived fossil fuels represented over 95% of all transportation energy consumed in the U.S. in 2012. Gasoline (63%), diesel fuel (22%) and jet fuel (15%) are the most widely used types of petroleum-based transportation fuels. Biofuels contributed only 4.5% of the total energy consumed for transportation in 2012, the majority of which (4.1% of the total transportation energy) is ethanol blended into gasoline. Dependence on non-renewable fuels, concern about global warming, and a push for greater energy independence led to adoption of the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007 (EISA) and the introduction of the Renewable Fuel Standards (RFS) in the U.S. These laws and regulations called for a reduction in annual petroleum consumption by at least 20%, an increase in the use of alternate fuels/biofuels such as ethanol and biodiesel by 10% by 2015, and a four-fold increase by 2022.

In 2012, ethanol constituted 94% of all biofuel produced in the U.S., and was produced primarily from corn. Other raw materials that can be used to produce ethanol include sugarcane, sorghum, beverage waste, cheese whey, cellulose and hemi-cellulose, corn stover, hardwood, and switch grass. Biodiesel, which in the U.S. is primarily made from soy oil, is another biofuel that is widely available. With technology improvements, low quality feedstocks, especially feedstocks from waste (trap grease from restaurants and sewer pipelines and other oil containing wastes) are expected to be increasingly used for biodiesel production and serve to provide waste reduction and renewable fuel production. Biodiesel can also be produced from algal lipids. Irrigation for biomass cultivation consumes the largest quantity of water in the production of biofuels. Water losses during cultivation also occur due to evaporation, evapotranspiration, and wind loss. Water is used for washing biomass to remove contaminants after harvest. In the production of ethanol, water is used for pretreatment, fermentation, and recovery processes, which may include the use of fresh, recycled/treated, or recycled/untreated/carried-over waters. Water is used to remove impurities during the processing of fatty-acid methyl esters that are used as biodiesel. Water is also used during cooling operations required for both ethanol and biodiesel production. The water used for processing biofuels is generally recycled, while the water used for cooking processes for ethanol production exits the plant as water vapor from cooling towers. Technology is available to build biofuel production plants capable of achieving zero discharge, if necessary, and using lower quality surface or gray waters is possible, which could play an important role in water-stressed regions.

In 2005, approximately 3% of the irrigation water used worldwide was used for the production of biofuels; by 2030, this proportion is projected to grow to approximately 30%. Additional technologies that can be used to minimize water usage include using pervaporation, which uses membrane separation to separate biofuels from water instead of steam distillation, membrane solvent extraction, which uses porous membranes to separate biofuel from the fermentation broth using an extracting solvent, or thermophilic yeasts, which minimizes the cooling required for the feed going into the fermentation unit. The amount of water consumed for producing ethanol and biodiesel from different fuel sources is listed in Table ES2. For comparison purposes, the amount of water consumed to produce gasoline and diesel from petroleum is also listed. Further information regarding water use in corn ethanol and cellulosic ethanol production can be found in Chapters 6 and 7, respectively, of this report. Further details regarding water use for biodiesel production can be found within Chapter 8 of this report.

Table ES2 Water intensities on a consumptive basis for producing different types of biofuels*

Fuel	Water used for Fuel Processing*	Water used for Crop Irrigation or Petroleum Extraction*
Gasoline	1 - 2.5	0
Ethanol (corn)	2.7 - 40 (13.4)[1]	15 - 934 (113)[1]
Ethanol (cellulose/switch grass +SRWC/corn stover)	12-17[2]	27 - 691 (28)[3]
Diesel Fuel Oil	1 - 2.5	0
Biodiesel (soy, current hydroxide TE)	0.3 - 0.5	1 - 1059 (62)[4]
Biodiesel (waste oil, acid-ester)	0.3	0
Biodiesel (algal, hydroxide TE)	1	40 - 1421 (554)[4]

Note: * - Water intensity in gal H_2O/gal fuel or m^3 H_2O/m^3 fuel

[1] Approximate average value based on King and Webber (see Chapter 6 of this report)

[2] See Chapter 7 of this report

[3] Approximate average value based on Tidewell et al.'s (2011) projections for 2030 (see Chapter 7)

[4] Approximate average value based on literature discussed in Chapter 8 of this report

Water, climate, electric generation and transportation fuel issues are closely interrelated and cannot be adequately addressed in isolation. Water stressed regions of the U.S. are expected to have continued population growth and energy demand. Additional stresses from climate change upon these regions is expected to result in freshwater scarcity becoming an issue of paramount importance. The majority of the water withdrawn and consumed by a thermoelectric generation is for used cooling steam. Finding alternative water resources to replace freshwater demand for thermoelectric cooling is both inevitable and urgent. Impaired waters and saline waters are potential alternatives to freshwater sources that could be used to meet future thermoelectric cooling needs. There is already some experience with the use of impaired water for thermoelectric cooling. Examples include the use treated municipal wastewater and the use of seawater in coastal areas.

One issue that has not been addressed in this report is the amount of energy required to transport and treat source water for power plant use as well as the energy required to treat wastewater from power plants. Additional research related to energy for water will be necessary, particularly for water-stressed regions of the U.S. Another topic that has not been addressed within this report and that is a potential area of future research is the use of waste biomass from secondary wastewater treatment processes to produce electricity (e.g., using microbial fuel cells), biofuels or methane gas, which can be used as a fuel source in wastewater treatment plants.

Laws and regulations put in place in response to climate change and the need to reduce U.S. dependence on foreign energy imports, e.g., RFS, RFS2 and EISA, mandate reductions in the use of petroleum-based fuels and increases in alternative fuels such as the biofuels ethanol and biodiesel. Biofuels also have significant water requirements, especially at the cultivation stage. Some of the same water-conserving techniques used by the energy industry such as recycling process water or using treated municipal wastewater can also be used in the biofuel industry. Additionally, more research is needed to assess the regional and local water impacts of different types of electricity generation and biofuel production, and to analyze the water impacts of electricity-sector choices. More studies of viable energy resources and the impacts of geographical limitations may be useful in adapting the use of water locally within the fuel and energy generation sectors.

1 Introduction

Timothy C. Keener [i]

Freshwater availability and future water demands have become major concerns in the U.S. when considering its historic economic growth and the ability to sustain its current quality of life. Past reports on water usage trends have shown that water demand is growing. Meanwhile, the capacity for surface water storage is becoming increasingly more limited and ground water is being depleted. Furthermore, population is rapidly increasing in water-stressed areas, especially in arid regions in the southwestern U.S. As will be shown in Chapter 4, the energy sector consumes massive amounts of water every year to provide electricity, and these amounts are expected to continue to grow unless steps are taken to utilize more efficient and renewable methods of generation and production. As described in Chapter 2, production of liquid fuels for transportation is also becoming increasingly water-intensive as the use of agriculturally-derived, renewable biofuels increases. Also, environmental conditions are increasingly becoming an important factor to consider while making decisions about the location, size and type of energy production methods necessary to supply the vast amounts of energy required to power our economy. As will be seen in Chapter 3, overall water demands nationally have changed little since the 1980s despite population growth on a national level. Water demands have changed within sectors and in different parts of the U.S. and often in places that are the most water stressed. The U.S. energy sector is in transition; biofuels use is increasing in the U.S. in response to policies that reduce transportation fuel imports. These factors also affect water use and consumption, especially in water-stressed regions. Finally, the U.S. has initiated a program to reduce greenhouse gas emissions from power plants and other sources in order to mitigate the impacts of climate change, making energy adaptation critical.

This report seeks to investigate and integrate the current knowledgebase of water usage in energy production industries, including the generation of electricity and the emerging production of biofuels. The report covers a discussion and explanation of the major areas of energy and biofuel production processes, including: 1) trends in energy production, future water availability and allocation for energy production, 2) the water resource impacts from coal-fired and natural gas-fired electric power plants, 3) the water resource impacts of production of corn-starch-based ethanol, biodiesel, biomass and cellulosic biofuel, and 4) water resource adaptation strategies for sustainable energy production using Las Vegas, Nevada as a case study.

While it is important to introduce the topics covered in this report, it is equally important to realize what this report does not address, as many areas of water usage in the energy sector were beyond the scope of this report or represent topics for future research. For instance, this report does not address in detail the substantial amounts of water consumption from the nuclear power industry, water consumed upstream of the energy production processes, such as water used in the mining of coal or the production of natural gas, the energy required to move the massive amounts of water used from one place to another since this is so site specific, energy required to desalinize the water that is used for producing steam or the energy required to reclaim water. The report does not directly address the impacts on water quality that the energy sector is

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responsible for, nor the ecological effects such water quality may create. Such studies are appropriate and necessary for future assessments of the overall impact of energy production on water and the environment.

Chapter 2 of this report discusses energy and energy production processes, which are an essential part of life in the U.S. today. This chapter briefly reviews the current coal- and natural gas-fired thermoelectric production methods (Rankine Cycle) and ethanol and biodiesel transportation fuel types, as well as their respective contributions to the total energy output in the U.S. and potential future energy production methods. The way that energy is generated, the sources that provide the energy and the contribution of each energy source to the total energy output are described. Future trends of each are discussed based on projections factoring in prior production, existing infrastructure, government regulations and available natural resources.

In Chapter 3, the impacts of climate change on water resources are discussed in the context of future energy and transportation biofuel production. The chapter provides an overview of attributes related to climate and population changes, and the degree of their impacts on water availability for future energy production. The impacts on energy production are multi-dimensional, affecting not only current energy production, but also future energy choices and overall makeup. To avoid redundancy with other recent reports (e.g., Tidwell et al., 2011; DOE, 2014), this chapter is only focused on the aspects of future water availability that could impact thermoelectric power production and biofuel production.

Chapter 4 discusses the water impacts from coal-fired thermoelectric power plants, including water required for capturing by-products such as flue gas, fly ash, and bottom ash. The term water consumption for these and other plants refers to the loss of water from the water source in a catchment area due to water evaporation, or return to another catchment area. The term water withdrawal refers to water that is removed from a water body. The main difference between water withdrawal, which is the traditional concept to measure water use, and water footprint is that the former does not consider the amount of water that is returned to the catchment area. Also, the water footprint concept includes the use of green and gray water in addition to direct and indirect use of water during the electricity production process.

Significant water volumes are required for the operation of thermoelectric plants as seen from the fact that in 2005, thermoelectric generation accounted for the largest percentage (41 percent) of all freshwater withdrawals in the U.S., with coal-fired power plants accounting for 67% of freshwater withdrawals among thermoelectric power plants. Depending upon the cooling and steam generation technology used, water withdrawal by the thermoelectric sector is expected to stay the same or decline slightly over the next 25 years. Nonetheless, water consumption is expected to increase from around 28 to nearly 50 percent on a national basis. It is projected that older power plants, which mainly use once-through cooling systems with high water withdrawal rates, are likely to be retired over the next 20 years. Facilities that have been built in the last two decades, and the ones projected to be built in the coming years, are most likely to employ wet recirculating cooling systems that have low withdrawal rates but high water consumption values. Other topics that are covered under this chapter include impacts of coal mining, wastewater treatment systems to treat flue gas desulfurization wastewater, potential to conserve and/or reuse water, and models to predict carbon dioxide generation and water withdrawal rates.

Chapter 5 addresses water usage from natural gas-fired thermoelectric power plants. Natural gas is the second largest fossil fuel used for electric power generation, accounting for 30% of total U.S. electricity production in 2012. However, this percentage is expected to increase as the emissions of carbon dioxide from coal thermoelectric plants are regulated to levels at or near those from natural gas thermoelectric plants. Due to the relatively low natural gas prices and capital costs, a natural gas plant is more competitive and an alternative choice for new generation capacity. According to EIA predictions in reference cases, natural gas power plants will account for 63% of electricity capacity additions from 2012 to 2040 (EIA, 2013).

Chapters 6, 7 and 8 discuss water consumption requirements for the production of biofuels, including corn-starch based ethanol production (Chapter 6), biomass and cellulosic production (Chapter 7) and biodiesel production (Chapter 8). The objective of the analysis contained in Chapter 6 is to systematically evaluate water usage impacts of the ethanol production process by studying existing ethanol plants. As concerns about global warming and dependence on fossil fuels grows, the search for renewable energy sources that reduce carbon dioxide emissions has become a priority. Although biofuels offer a diverse range of promising alternatives, ethanol constitutes 94% of all biofuels produced in the U.S. in 2012. At present, virtually all U.S. fuel ethanol is produced from the fermentation of corn in dry and wet milling plants, most of which are located in the Midwestern states (Wang, 2005). The methodologies applied within the analysis are mathematical modeling of the energy balance (including thermal energy and electricity) and the mass balance (including corn input, water usage, wastewater discharge, co-products and CO_2 emissions) with respect to the various process system boundaries.

Cellulosic ethanol production is discussed in Chapter 7. In this chapter, the water requirements for biomass harvesting and cellulosic ethanol production via a fermentation pathway are assessed on a volume-to-volume basis (i.e., gallons of water consumption per gallon of ethanol production) using data reported in the literature. The water requirements have been analyzed for a combination of three feedstocks (e.g., hardwood, corn stover and switch grass) and two pretreatment technologies (e.g., dilute acid and ammonia fiber expansion) under different water network configurations with an overall goal of zero wastewater discharge. The results indicate that the process water requirements are significantly dependent on the selection of pretreatment processes and feedstocks, while effective cooling tower design and operation of a cooling tower offers an opportunity for saving water.

Chapter 8 investigates water consumption from the processing of biodiesel. The production of biodiesel has become a globally mature industry with many diesel vehicles now capable of using higher percentages of biodiesel fuel, with many more in the design and production stages. In the U.S., a record high of 1.1 billion gallons of biodiesel were produced from 193 biodiesel manufacturers in 2012, compared to 28 million gallons in 2004. The chapter begins with a summary of the current status of the U.S. biodiesel industry, followed by an estimate of water consumption for the processing of lipids into biodiesel. Currently, soy oil is the primary source of lipids that are processed into biodiesel fuel in the U.S. The analysis of water consumption from biodiesel production processes began with a survey of relevant literature, and then determining characteristic allocation factors for each of the various stages' methods. Both state-level estimates and national averages of water consumption have been determined and compared with several relevant studies in detail. Water consumption patterns of water-stressed areas have also been summarized. The chapter concludes with a discussion of future biodiesel trends, including the use of new feedstocks and the use of new biodiesel production technologies since these changes can also affect water use. Water use from algal biodiesel is also briefly summarized.

In Chapter 9, an assessment of the impacts of electric power generation on water availability has been made for the water-stressed areas of Arizona, California, New Mexico, Nevada, Texas and Utah. Thermoelectric power plants in the southwest will most likely face significant challenges regarding water withdrawal and water consumption because they are located in an arid region. The impacts of the water withdrawals are exacerbated by increased population migration to the region and reduced regional precipitation. Water that is removed for cooling purposes in thermoelectric plants and not available for other uses is an especially important consideration for water-scarce regions, and is particularly relevant in future energy resource development adaptation strategies. Changes in energy regulations and policies as well as shifts in the electricity generation portfolio toward implementing innovative technologies, can therefore, be expected to have significant impacts on the management of local, regional and national water resources.

Finally, Chapter 10 provides a discussion about the future of a sustainable water-energy nexus, including an assessment of the vulnerability of such a future with a discussion of how adaptive engineering may be useful in overcoming obstacles. The chapter concludes with a discussion of current knowledge gaps, and future research and development issues that may need to be resolved to overcome these gaps.

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2 Trends in Energy Production

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2.1 Introduction

The total energy production in the U.S. in 2012 was 95 quadrillion BTUs (EIA, 2014a). Electricity generation and transportation are two of the largest sources of energy demand in the U.S, accounting for over half of the total energy production. This chapter discusses the current electricity production methods and transportation fuel types, their respective contributions to the total energy output in the U.S., and potential future energy production methods. The way that energy is generated, the sources that provide the energy, and the contribution of each energy source to the total energy output are described. Future trends of each are discussed based on projections factoring in prior production, existing infrastructure, government regulations and available natural resources.

2.2 Current Energy Production Methods

2.2.1 Electrical energy demand and production

In 2012, total electricity demand was 3,826 billion kilowatt-hours (kWh) (13 quadrillion BTUs) in the U.S. (EIA, 2014a). The largest consumption of electricity is for residential applications (36%) such as lighting, heating or cooling, home appliances and consumer electronics, while the commercial and industrial sectors consume 35% and 26%, respectively (EIA, 2014a).

Electricity demand fluctuates with respect to many factors. Weather conditions, prices and business cycles are the dominant factors that impact electric demand on a short-term basis. There has been a steady increase in demand for electricity over the last century, although this increase has slowed somewhat in the decades since 1950. The growth rate is predicted to be 0.8% per year through 2035, down from 9% per year in the 1950s and 2.5% per year in the 1990s, (EIA, 2014a).

Most of the electricity in the U.S. is generated by fossil fuel combustion using steam turbines. Fossil fuels such as coal, natural gas, and petroleum oil are burned in a boiler furnace to produce steam. The kinetic energy of the steam is converted to mechanical energy within a steam turbine to provide shaft-work to drive electrical generators.

Among fossil fuels, coal and natural gas have been the most common fuels used to generate electricity. Historic and projected electrical production and the contributions of each energy source are shown in Figure 2.1. Coal was used to generate nearly 37% of the 4 trillion kWh (1.3×10^{16} BTUs) of electricity used in the U.S. in 2012, followed by natural gas at 30%.

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By comparison, nuclear power and renewable energy provided 19% and 12% of the total energy output, respectively (EIA, 2014a).

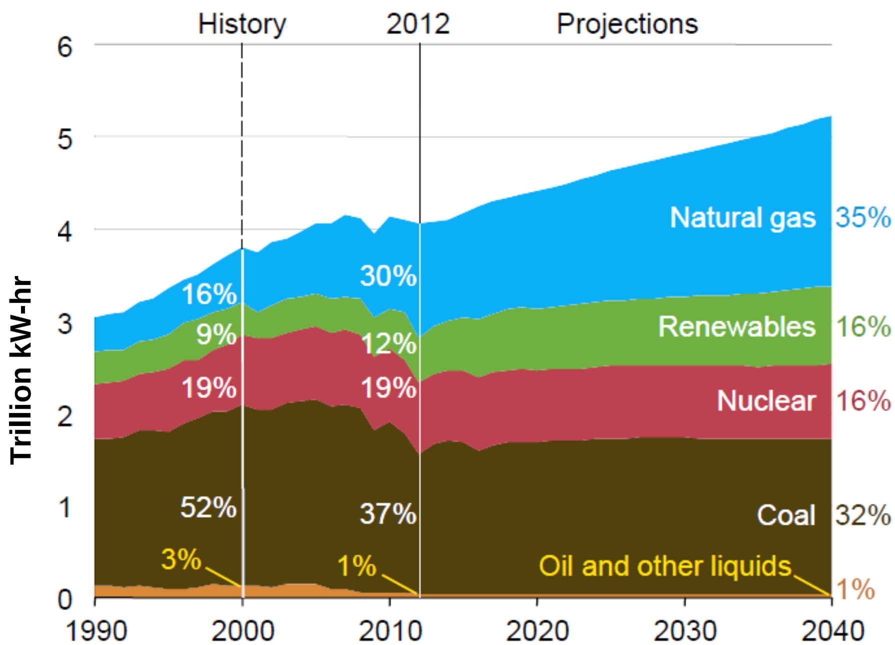

Figure 2.1 Electricity generation and energy source contributions. Adopted from EIA (2014b).

2.2.2 Transportation fuels

The majority of the transportation in the U.S. is done using motor vehicles utilizing liquid fuels. A total of 26.7 quadrillion BTUs of energy was used for transportation in 2012 (EIA, 2014a). Petroleum-derived fossil fuels represented over 95% of all transportation energy consumed in the U.S. in 2012. Gasoline (63%), diesel fuel (22%) and jet fuel (15%) are the most widely used types of transportation fuels (EIA, 2014a). These percentages also take into account blends of crude-oil-derived gasoline and diesel fuel with biofuels such as ethanol and biodiesel.[6]

Biofuels contribute only 1.2 quadrillion BTUs, or 4.5% of the total energy consumed for transportation, the majority of which (4.1% of the total transportation energy) is ethanol blended into gasoline. Jet fuel accounted for the majority of the approximately 15% remainder in transportation fuel consumption in 2012, with other transportation fuels such as natural gas, propane and hydrogen, or energy sources such as electricity for battery electric or plug-in hybrid vehicles, contributing less than 1%.

Overreliance on non-renewable fuels and a push for greater energy independence led to the introduction of the Renewable Fuel Standards (RFS), which was established in 2005 as part of the Energy Policy Act (EPAct), which was then amended in the 2007 Energy Independence

[6] Gasoline in the United States may be blended up to 10% with ethanol. The ASTM D975 specification for No. 2 diesel fuel oil includes blends of up to 5% biodiesel.

and Security Act (EISA). EPAct and then EISA were established to set up goals and requirements to secure energy independence for the U.S. (U.S. DOE, 2010). The act defines the goal of a reduction in annual petroleum consumption by at least 20%, and a 10% increase in renewable and alternative fuel use by 2015 from the 2005 baseline. The renewable and alternative fuel requirements have led to an increase in production of ethanol and biodiesel. U.S. production of biofuels approximately tripled in volume between 2005 and 2012 (EIA, 2014c; see Figure 2.2). Ethanol is the primary biofuel used in the U.S. today, and is primarily produced by the conversion of sugars from grain into alcohol (ethanol), which is then purified through distillation. The main source of ethanol is corn, but other sources include sorghum, barley, sugarcane and other agricultural feedstocks.

Almost all gasoline used in vehicles in the U.S. contains some percentage of ethanol, typically 10% by volume (E10). In 2010 and 2011, EPA granted two partial waivers that allow, but do not require, the use of E15 in model year 2001 and newer light-duty motor vehicles, subject to certain conditions (U.S. EPA, 2013a). Higher ethanol percentages can be used, but only if the vehicle has been designed to handle the higher concentration of ethanol, which can cause deterioration of fuel system components unless they are specifically designed for such use. The most common high concentration blend is E85 (85% ethanol blend), which is used in flex-fuel vehicles. E85 accounted for only 0.014 quadrillion BTUs of energy used for transportation in 2012, or 1.3% of all ethanol-blended gasoline. Biodiesel is the next most common biofuel. It is a mixture of fatty acid methyl esters (FAME) produced primarily from a trans-esterification reaction between triglycerides (oil) and methanol with alkali catalysts. Current biodiesel feedstocks in the U.S. are primarily from seed-crop oils (e.g., soy oil, rapeseed oil) and animal fats (e.g., tallow and lard). Biodiesel blends of 5% (B5) with petroleum diesel fuel are capable of being used in most modern diesel engines without modification and blends up to 20% (B20) can be used in several of the most recent engine manufacturer offerings, but biodiesel is not currently produced in large quantities. Biodiesel accounted for approximately 1,159 and 1,244 trillion BTUs (991 and 1,339 million gallons in 2012 and 2013, respectively) in 2012 and 2013, respectively, or 10% and 14% (114 Btu in 2012 and 175 Btu in 2013) of all the transportation energy produced from biofuels in 2012 and 2013, respectively (EIA, 2014d).

Along with the growth of biofuel production, there has been a rapid expansion of the feedstock market. However, due to an ongoing "food vs. fuel" debate (Canali and Aragrande, 2010; Cassman and Liska, 2007; Tilman et al., 2009), high feedstock costs (Haas, 2011) and concerns over sustainability that include water use (King and Webber, 2008, Dominguez-Faus et al., 2009} and land use (Rathmann et al., 2010, Achten et al., 2011), renewable fuel producers are also actively investigating alternative feedstocks. For example, Table 2.1 shows a summary of water consumption for gasoline, petroleum diesel, E85 from corn grain (starch) and corn stover (cellulose), and soybean biodiesel from the literature. The water consumption for producing the biofuels is significantly higher than for producing petroleum fuels, mostly due to irrigation requirements. The potential for new biofuel feedstocks is discussed further within Chapter 8 of this report.

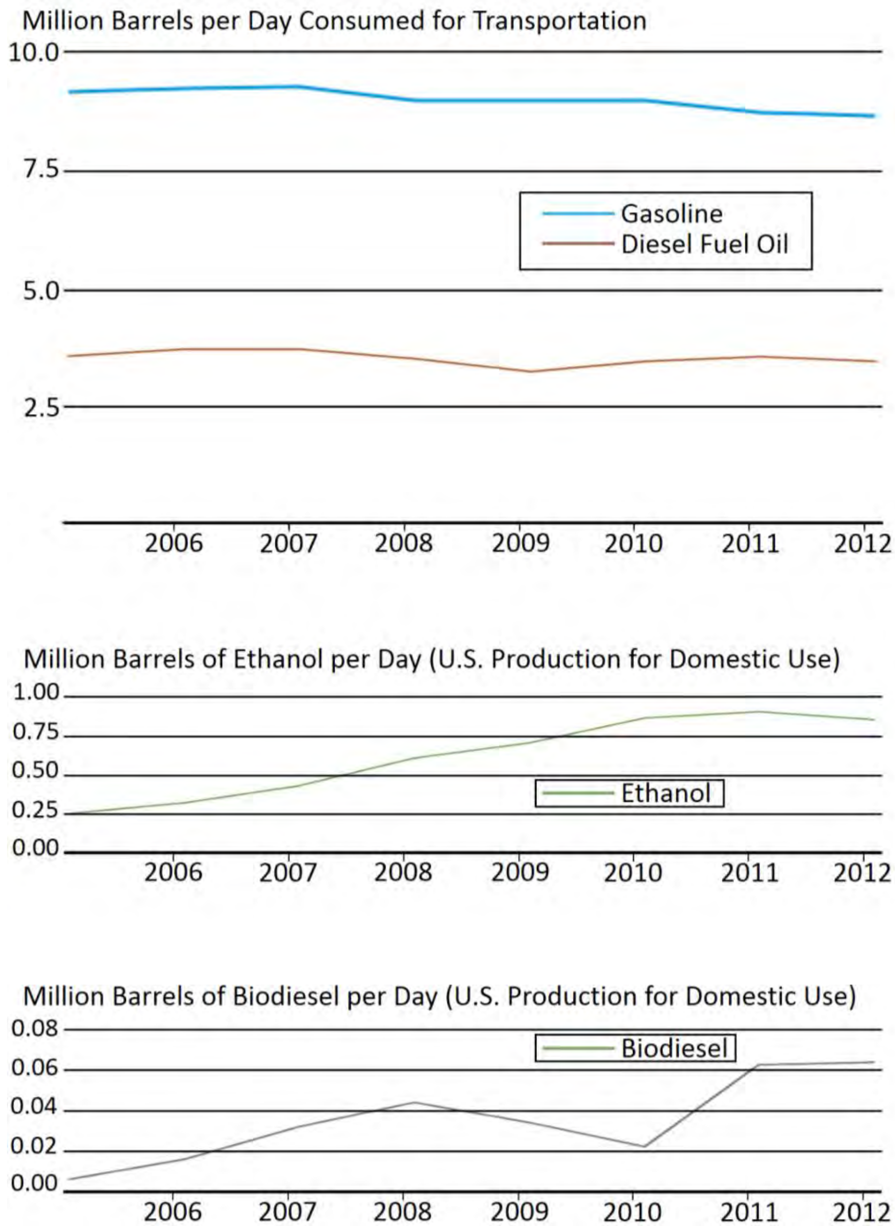

Figure 2.2 Comparison of the use of gasoline and diesel transportation fuels to domestic production of biofuels. Note the difference in scales for the charts of petroleum, ethanol and biodiesel fuels, respectively. Gasoline consumption is dominated by light-duty vehicle use and in 2012, ethanol accounted for ~10% of light-duty fuel consumed. Adopted from EIA (2014c).

Table 2.1 Fuels production water intensity

Transportation Fuel	Consumption (gal/gal)
Gasoline from Liquid Petroleum	1-2.5
Diesel from Liquid Petroleum	1-2.5
E85 from Irrigated Corn Grain	20-936
E85 from Non-Irrigated Corn Grain	2-5
E85 from Irrigated Corn Stover	39-695
E85 from Non-Irrigated Corn Stover	4
Biodiesel from Irrigated Soy	15-617
Biodiesel from Non-Irrigated Soy	0.3-0.5

Source: King and Webber (2008).

2.3 New Energy Technologies and Future Outlook

2.3.1 Trends in advanced coal technologies for power production

Because of the increasing problem of CO_2 and other greenhouse gas (GHG) emissions, the large fraction of electricity currently produced from fossil fuel power plants, Clean Air Act compliance requirements, and the predicted lack of alternative energy sources, there is a need to develop next-generation technologies that enable reliable, low-cost, low-carbon energy from fossil fuels, particularly coal. While natural gas is expected to displace some coal-fired electric generation capacity, it must be noted that coal-fired power plants offer benefits that include low cost and affordable power rates in many parts of the world. Advanced coal technology development efforts in the U.S., for example the U.S. DOE Clean Coal Research and Development Program, have focused on developing and demonstrating novel concepts of power generation, carbon capture, utilization, storage, and conversion technologies for existing facilities and new fossil-fueled power plants while increasing overall system efficiencies and reducing capital costs (U.S. DOE, 2014). In the near-term, advanced technologies that increase the efficiency of power generation for new plants, and technologies to capture carbon dioxide (CO_2) from new and existing industrial and power-producing plants, are being developed with the assistance of U.S. DOE funding (U.S. DOE, 2014). Carbon capture, however, consumes energy and reduces the overall efficiency of the plant. In the longer-term, there will be continued focus on increasing energy plant efficiencies, and reducing both the energy and capital costs of CO_2 capture and storage from new, advanced coal plants and existing plants (U.S. DOE, 2014). These strategies will ensure a diverse future energy portfolio for electric power generation.

One approach to making the capture of carbon dioxide in exhaust gas cost-effective is to combust the coal in oxygen-enriched air (by removing nitrogen) and recycle the exhaust gas to serve the role of the diluent. This is known as oxy-combustion. Such a configuration would result in a carbon dioxide concentrations of up to 95% [7], making it more feasible to capture CO_2 (Suriyawong et al., 2006; Wang et al. 2012). Other advantages include reduced volume of flue gas to exhaust, potential for increasing boiler thermal efficiency, elimination of thermal NO_X (due to removal of nitrogen from the air stream), decreasing the conversion ratio of fuel-N to exhaust NO_X (nitrogen in the fuel that is converted to NO_X during combustion), and increasing the reduction of NO_X to N_2 (removal of NO_X before exiting the plant).

A variant of the oxy-combustion currently being tested at the pilot-scale level is the chemical looping combustion process (Fan, 2011; Feeley, et al., 2007). Chemical looping splits combustion into separate oxidation and reduction reactions. A metal (e.g., iron, nickel, copper or manganese) oxide releases oxygen in a reducing atmosphere, which can then react with the fuel to provide energy. The metal is then recycled back to a zone where the metal oxide is regenerated in contact with air. The two sections used for the combustion process allow CO_2 to be concentrated, and when the water produced during combustion is removed, it is not diluted with the nitrogen from air. The advantage of this process is that no air separation units or external CO_2 separation equipment is needed (Feeley, et al., 2007).

2.3.2 The emerging role of natural gas in power generation

Electric power generation and the industrial sector are the two largest sectors of natural gas consumption in the U.S. (EIA, 2014e). Due to the increased use in these two sectors, natural gas consumption is predicted to grow by about 0.6 percent per year from 2011 to 2040. Natural gas accounted for 30% of total electricity generation in 2012. It is projected to increase to 35% in 2040 (Figure 2.1). Due to the domestic production of natural gas from shale deposits in North America, the price of natural gas is likely to remain under the levels observed in 2005-2008. Compared with coal-fired power plants, the relative low cost of natural gas makes the operation of existing natural gas-fired power plants increasingly competitive with coal-fired power plants (EIA, 2012). In addition, comparatively low capital costs make natural gas power plants an attractive alternative choice as future decisions are made to bring new electrical generation capacity online (EIA, 2014e).

2.3.3 Other alternative energy developments

Nuclear and renewable energy provided, respectively, 19% and 12% of the total electricity generation in the U.S. in 2012. Renewable energy sources include hydroelectric power, wind, biomass wood and waste, geothermal and solar. The largest share of renewable-generated electricity was from hydroelectric power. It generated 56% of the total electricity from renewable sources, followed by wind (28%), biomass wood (8%), biomass waste (4%), geothermal (3%) and solar (1%) (EIA, 2014f).

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[7] 95% CO_2 represents a theoretical limit. In practice, CO_2 concentrations are lower, primarily due to air-leakage.

In 2011, a total of 104 commercial nuclear power plants were in operation and generated 886 billion kWh (3.02 quadrillion BTUs) of electricity. This share is projected to increase until 2025, and to eventually reach 1000 billion kWh (3.41 quadrillion BTUs). After a projected decline in 2036, mainly due to plant retirements, newly built nuclear power plants are expected to bring nuclear capacity back up to 991 billion kWh (3.38 quadrillion BTUs) in 2040. However, the share of nuclear power in the U.S. energy profile is expected to decrease as the increases of generation capacity from renewable sources and natural gas outpace the growth of nuclear generation (EIA, 2014f).

The use of renewable energy in electricity generation depends on both the availability of resources and the generation capacity that is required by the applications. Nearly all current hydroelectric power plants were built in the mid-1970s. They were mostly built at dams operated by federal agencies. Most of the wood biomass is used as an energy source by lumber and paper mills to generate steam and electricity on-site for their own needs. As of 2012, there were 13 solar thermoelectric plants[8] that generated electricity by concentrating solar energy to heat fluids that power a steam turbine generator. Solar photovoltaic cells can be used on a relatively small scale for individual buildings or on a much larger scale as part of "solar farms" that provide electricity to specific industrial applications (e.g., Microsoft, Facebook, Amazon or Google data server farms) or directly to the electric grid. Solar energy generated at small-scale installations, such as on individual building roof-tops, generated 9.86 billion kWh of energy in the U.S. in 2013 (EIA, 2014a).

Government policies also affect the use of renewable energy for electricity generation. For example, state and regional programs and federal financial incentives have driven an increasing share of wind generation during the past decade. Wind and solar power generation are expected to lead the renewable energy category, increasing from 59 and 8 GW, respectively, in 2012 to 87 and 48 GW, respectively, in 2040 (EIA, 2014g). Other sources, such as biomass and geothermal, are expected to continue to increase, but at a much slower pace, while hydropower will remain almost constant over the entire period.

2.3.4 Regulatory impacts on future electric power generation

U.S. EPA has published a set of regulations under the Clean Air Act (CAA) for stationary source GHG mitigation. In 2010, the U.S. EPA issued the Greenhouse Gas Tailoring Rule to address GHG emissions from stationary sources under CAA permitting programs (U.S. EPA, 2010a). These regulations set thresholds for GHG emissions that define when permits under the New Source Review Prevention of Significant Deterioration (PSD) and title V Operating Permit programs are required for new and existing industrial facilities. This final rule "tailors" the requirements of these CAA permitting programs to limit what facilities will be required to obtain PSD and title V permits. Facilities responsible for nearly 70% of the national GHG emissions from stationary sources will be subject to permitting requirements under this rule. This includes the nation's largest stationary GHG emitters—electric power plants, refineries and cement

[8] There were eleven solar thermoelectric plants in CA, one each in FL and NV, and one in FL that provides supplemental steam for an existing oil and gas-fired power plant.

production facilities. Emissions from small farms, restaurants and all but the very largest commercial facilities are not covered under these regulations.

In September 2013, the U.S. EPA proposed a Carbon Pollution Standard for New Power Plants (U.S. EPA, 2013b). This program would establish new national limits on the amount of carbon pollution emitted by future electric power plants. The proposed standards would apply only to new fossil-fuel-fired electric utility generating units. EPA proposed CO_2 standards of performance for sources within the following subcategories:

- 1,000 lb CO_2/MWh for natural gas-fired stationary combustion turbines with a heat input rating to the turbine engine that is greater than 850 MMBtu/hr;
- 1,100 lb CO_2/MWh for natural gas-fired stationary combustion turbines with a heat input rating to the turbine engine that is less than or equal to 850 MMBtu/hr, and
- 1,100 lb CO_2/MWh for all other fossil fuel-fired boilers and IGCC units

The proposed standards would not apply to plants currently operating or to newly permitted plants that begin construction during the 12 months following adoption of the regulation. For existing power plants, EPA issued proposed Carbon Pollution Standards on June 2, 2014 (U.S. EPA, 2014a) that reduces power plant GHG emission for each state by 30% relative to 2005 by 2030.

Nearly all (95%) of the natural gas combined cycle (NGCC) units built since 2005 would meet the proposed GHG standards; so, it is expected that any new NGCC power plants would be able to meet the proposed standards without additional emission controls. New power plants that are designed to use coal or petroleum coke would need to incorporate technology such as carbon capture and sequestration to reduce CO_2 emissions sufficiently to meet the proposed standards.

The capture and injection of CO_2 produced by human activities for storage via long-term geologic sequestration is one of a portfolio of options that are expected to reduce CO_2 emissions to the atmosphere from large stationary sources of GHG emissions. Geologic sequestration that may occur from future carbon pollution stationary-source standards under the authority of the CAA must be performed in a manner that safeguards underground sources of drinking water, such as aquifers, as required by the Safe Drinking Water Act (SDWA). In December 2010, the U.S. EPA finalized “Federal Requirements under the Underground Injection Control for Carbon Dioxide Geologic Sequestration Wells” (U.S. EPA, 2010b) under the authority of the SDWA’s Underground Injection Control (UIC) Program. These requirements, also known as the Class VI rule, are designed to protect underground sources of drinking water from CO_2-injection related activities. The Class VI rule builds on existing UIC Program requirements, with extensively tailored requirements that address CO_2 injection for long-term storage to ensure that wells used for geologic sequestration are appropriately sited, constructed, tested, monitored, funded and closed. The rule also affords owners or operators injection depth flexibility to address injection in various geologic settings in the U.S. where geologic sequestration may occur, including very deep formations, and oil and gas fields that are transitioned for use as CO_2 storage sites.

2.3.5 Future biofuel usage

The “Annual Energy Outlook 2014” (AEO 2014) published by the Energy Information Administration (EIA, 2014a) shows the predicted total petroleum and other liquid fuel production from 2012 through 2040 (Figure 2.3). It should be noted that these predictions are based on available information at the time of its publication (April 2014) and may vary significantly from the actual future values. Market forces, technological advancement, and regulations all would have a significant impact on these predictions. The AEO 2014 report predicts flat production of biofuels over the next three decades, largely due to difficulties with increasing the use of ethanol. Ethanol production will remain relatively flat or decrease slightly through 2040 due to a decrease in gasoline usage, the limited availability of flex fuel vehicles capable of operation on ethanol blends above E15, the limited availability of retrofitted filling stations capable of dispensing higher ethanol blends The production of biodiesel is projected to be constant as well, based on the assumption that the required volume under RFS for biomass-based diesel will remain at 1.28 billion gallons. The outlook also indicates that biofuel consumption may fall short of the EISA2007 goal of 36 billion RFS credits (Figure 2.4). The major reason is the decrease in gasoline consumption due to the recently enacted Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy (CAFE) Standards (U.S. EPA, 2010c, 2012) and updated expectations for the sales of E85 compatible vehicles. For example, the data shows that the projection of E10 and E15 demand drops from 8.7 million barrels per day in 2012 to 7.9 million barrels per day in 2022 and 6.7 million barrels per day in 2040 (Figure 2.5).

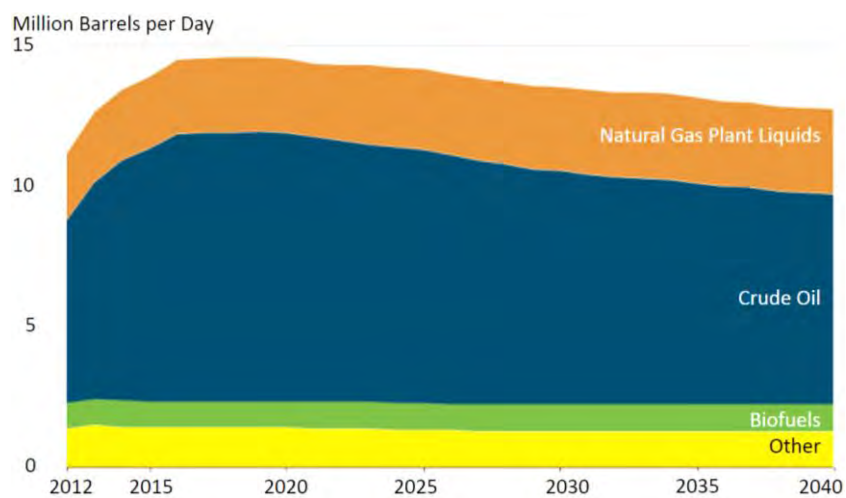

Figure 2.3 U.S. production of petroleum and other liquids by source, 2012-2040 (million barrels per day). Adopted from EIA (2014b).

The proposed standards in the 2014 RFS, which are still under consideration and subject to change before final approval, are structured to ensure continued growth of renewable fuels while recognizing the practical limits on ethanol blending known as the ethanol “blend wall” (U.S. EPA, 2013c). The blend wall refers to the difficulty in incorporating increasing amounts of ethanol into the transportation fuel supply at volumes exceeding those achieved by the sale of nearly all gasoline as E10. The proposed standards cover both ethanol and non-ethanol biofuels, and would establish a total annual volume of 15.21 billion gallons of renewable fuels (see Table 2.2). As shown in Figure 2.6, the proposed ethanol shares of the total gasoline pool (green line) for both 2013 and 2014 are almost constant at approximately 10% due to the reduction in gasoline consumption (blue line) in the U.S. This percentage is less than the amount anticipated when the U.S. Congress established the program in 2007.

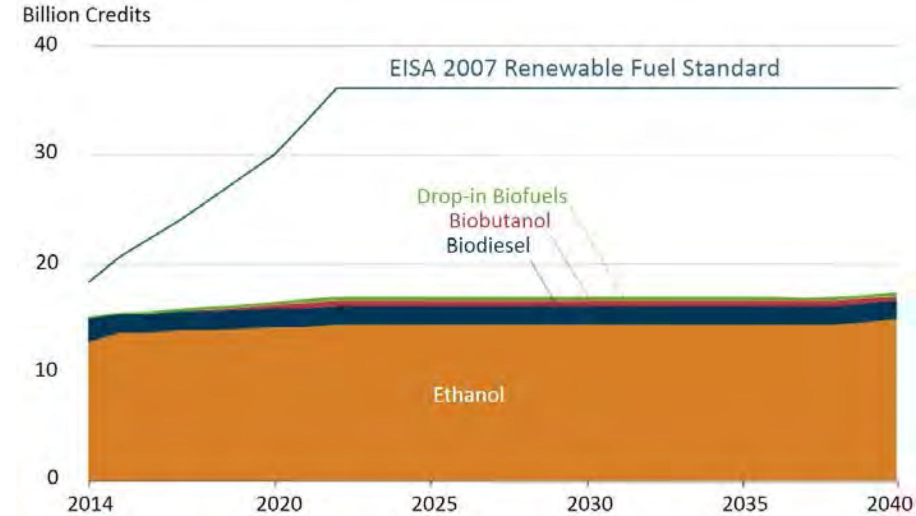

Figure 2.4 EISA 2007 RFS credits earned in selected years, 2012-2040. Adopted from EIA (2014b).

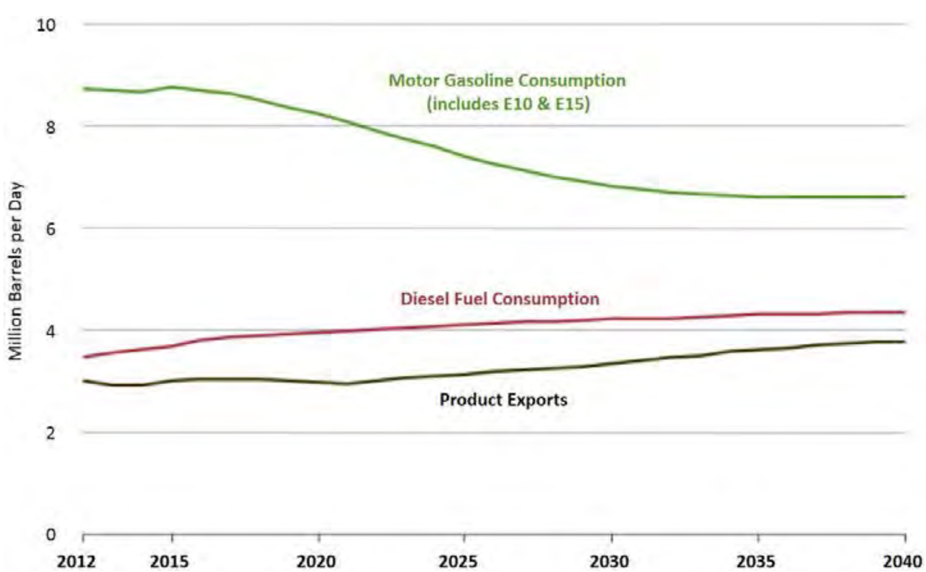

Figure 2.5 Projections of U.S. domestic gasoline and diesel fuel consumption through 2040. Exports of refined products are also shown. Adopted from EIA (2014b).

Table 2.2 Proposed volume for 2014 RFS

Category	Volume (% of All Fuels)
Cellulosic biofuel	17 million gallons (0.010 %)
Biomass-based diesel	1.28 billion gallons (1.16%)
Advanced biofuel	2.20 billion gallons (1.33%)
Renewable fuel	15.21 billion gallons (9.20%)

Source: U.S. EPA (2014c)

The daily supply of ethanol in the projected period (2012-2040) is in the range of 0.83 to 0.95 million barrels, with an annual growth rate of 0.5%. Both ethanol blending into gasoline at 15% or less and E85 consumption for energy use are also essentially flat with an annual growth rate of 0.6% throughout the projection period (2012-2040) as a result of declining gasoline consumption and limited penetration of flex-fuel vehicles capable of operation on fuel blends of up to 85% ethanol (EIA, 2014h). Flex-fuel vehicles are projected to represent only 11% of all new light-duty vehicles sales in 2040. The wholesale price of ethanol for transportation was projected to be near constant from 2012 to 2040, with an average price of $2.5 to 2.6/gal.

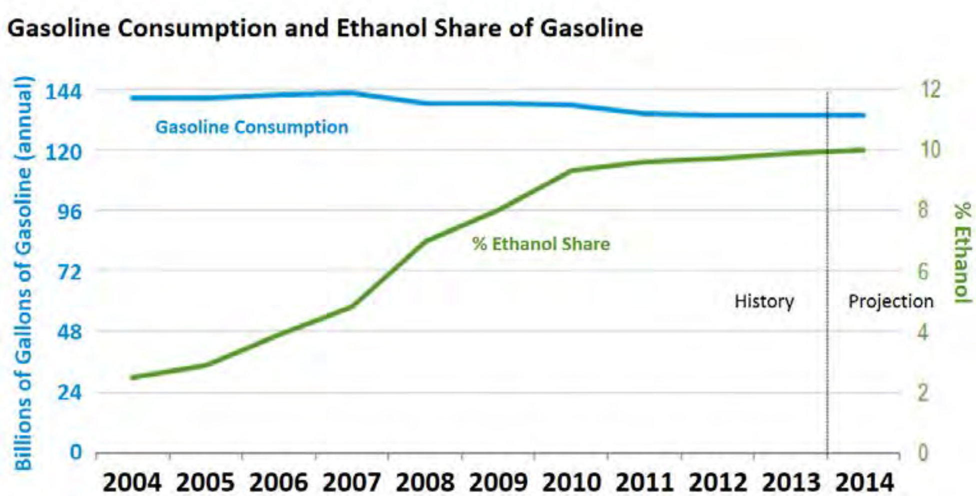

Figure 2.6 Gasoline consumption and percentage ethanol share of gasoline. Adopted from EIA (2014i).

As shown in Figure 2.7, consumption of E15 and E85 fuels is predicted to increase at the expense of E10, but total ethanol biofuel consumption is expected to decrease as a whole by 2040. Starting in 2020, E15 is expected to slowly penetrate the motor gasoline market, as blend wall issues are assumed to be resolved over time and, by 2040, will make up approximately 40%

of the total motor gasoline market. The increase in consumption of E15 is based on an assumption that consumers, refiners and vehicle manufacturers will transition to E15 from E10, choose E15 over E85 and other blends, and that infrastructure constraints will be resolved gradually over time (EIA, 2014h).

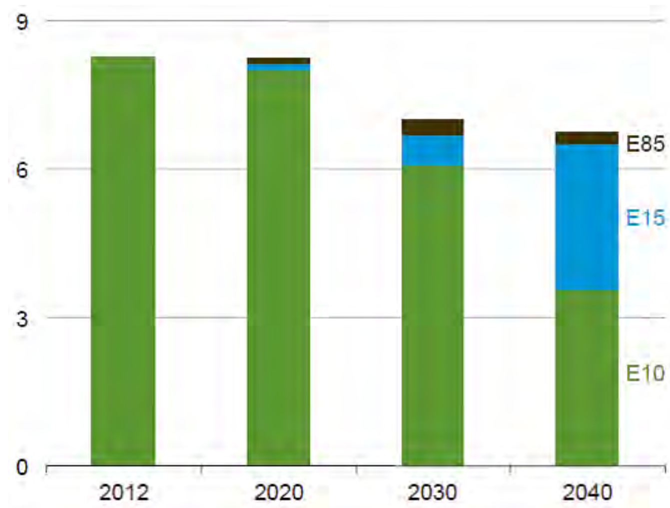

Figure 2.7 Consumption of biofuels in motor gasoline blends in the Reference case, 2012-2040 (million barrels per day). Adopted from EIA (2014b).

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3 Climate Change Impacts on Water Availability for Energy Production

Y. Jeffrey Yang[i]

3.1 Introduction

Climate change affects water availability. At the same time, population growth and redistribution affect the degree and spatial distribution of water demand. This further exacerbates the stress that climate change places upon water resources. Most of all, the Nation's regulatory programs, such as those impacting ecological stream flow and Section 305 of the Clean Water Act (CWA), are overriding considerations for sustainable water resource development, especially in water-stressed regions. The confluence of these factors can impact the relationship between water and energy and affect development of sustainable energy production in the future.

Climate is a statistical term that describes the mean and standard deviation of "weather" over a period of time - usually 30 years as defined by the World Meteorological Organization (WMO). This time frame is compatible with long-term planning for energy production, and therefore, the impact of climate change on water resources is a necessary element to consider during such planning. Two terms are pertinent to this discussion and require clear definitions given the similarity of their meanings: climate variability and climate change. Climate variability refers to temporal variation of the climate mean and other statistics due to internal variability of the climate system, or the external variability in external forcing. Climate change is defined as a statistically significant difference in the climate mean or variation over an extended period of time as a result of natural or man-made climate forcing. In other words, climate variability pertains to a hydroclimatic state (mean and variation) over a time period, whereas climate change is related to a significant change of this state. Both terms are relevant and should be distinguished for the analysis of impacts of water resources on energy and transportation fuel production.

Climate change affects the interaction among airshed and watershed processes, exerting impacts on water quantity and quality, air quality, and consequently influencing the ways in which energy production will adapt in the future. There are numerous publications in the literature that document the nature of potential impacts, specifically in watershed hydrology sectors such as stream flow, storm runoff, and water quality. Impacts on ambient air temperature and ecological conditions in wetlands and coastal regions have been documented in prior EPA and other assessment reports (USCCSP, 2008; U.S. EPA, 2009).

This chapter begins with a general assessment of hydroclimatic changes for which the historical precipitation records spanning approximately 100 years were analyzed and the results of climate change projections are summarized. Details of this historical precipitation analysis and climate model projections can be found in a companion EPA report (U.S. EPA, 2014a,b). Subsequently, a section of this chapter is devoted to describing population change and spatial shifts in the U.S. that have resulted in significant land use changes. The combined effects from climate change and land use changes affect surface water flow and water availability at

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watershed scales. Three examples are used to illustrate the projected future watershed river flow changes that should be considered for electric power production. They include the Colorado River basin and its Lower Virgin River tributary, the Mississippi River basin and the agricultural Little Miami River watershed. As shown in these examples, climate-induced hydrological changes appear to have significant potential to limit energy production in at least two ways: 1) stream flow decreases in the U.S. will have implications with respect to cooling water discharge from thermal electric power plants, and 2) shifting regional precipitation has an effect on domestic biomass production for transportation fuels. Details of thermoelectric power production and biofuel production processes are described along with quantification of their impacts on water resources in subsequent chapters of this report.

3.2 Climate change projections and water availability outlook

3.2.1 Climate systems controlling U.S. precipitation and water availability

Two major aspects of climate dynamics are affecting continental precipitation and water variability in the contiguous U.S. One is the manner in which ocean-origin climate systems are coupled to inter-annual, decadal and multi-decadal precipitation variability. These systems operate on both continental and global scales. The other is the manner in which regional and local factors are responding to planetary boundary feedbacks, including the effects of large topographic features and land use in North America. In the next 30 to 50 years, local climate forcing from topography, surface water bodies, and major categories of land use will remain relatively unchanged, given no significant and disruptive human-environment interactions. The interactions will continue into the future, and will superimpose onto the effects of large-scale climatic systems.

The resulting precipitation variations are shown through variables such as precipitation intensity, frequency, seasonality, and total amounts. These variables all affect water availability in surface water flow and groundwater levels, timing of snow melt, and are thus consequential to energy production processes. Precipitation variability can be analyzed mathematically by using wavelet patterns and analysis methods (Torrence, 1998; Keener, 2010) in order to reveal the spatiotemporal properties of the precipitation. Details of a precipitation variability wavelet analysis and analytical results will be presented in the following sections of this chapter. The major climate systems affecting continental precipitation are summarized in the following subsections.

3.2.1.1 Continent-Ocean interactions

The schematic in Figure 3.1 illustrates major climate systems and regional/local climate factors that influence synoptic-scale precipitation in the contiguous U.S. In a physiographic setting, the U.S. is bounded by the Pacific Ocean, the Atlantic Ocean, and the Gulf of Mexico. As such, synoptic precipitation is influenced by large-scale climatic systems, including the El-Niño Southern Oscillation (ENSO), Pacific Decadal Oscillation (PDO), North Atlantic Oscillation (NAO) and Atlantic Multidecadal Oscillation (AMO) systems (IPCC, 2007; Durkee et al., 2007; USCCSP, 2001). Arctic Oscillation (AO), Aleutian Low, surface albedo, and other

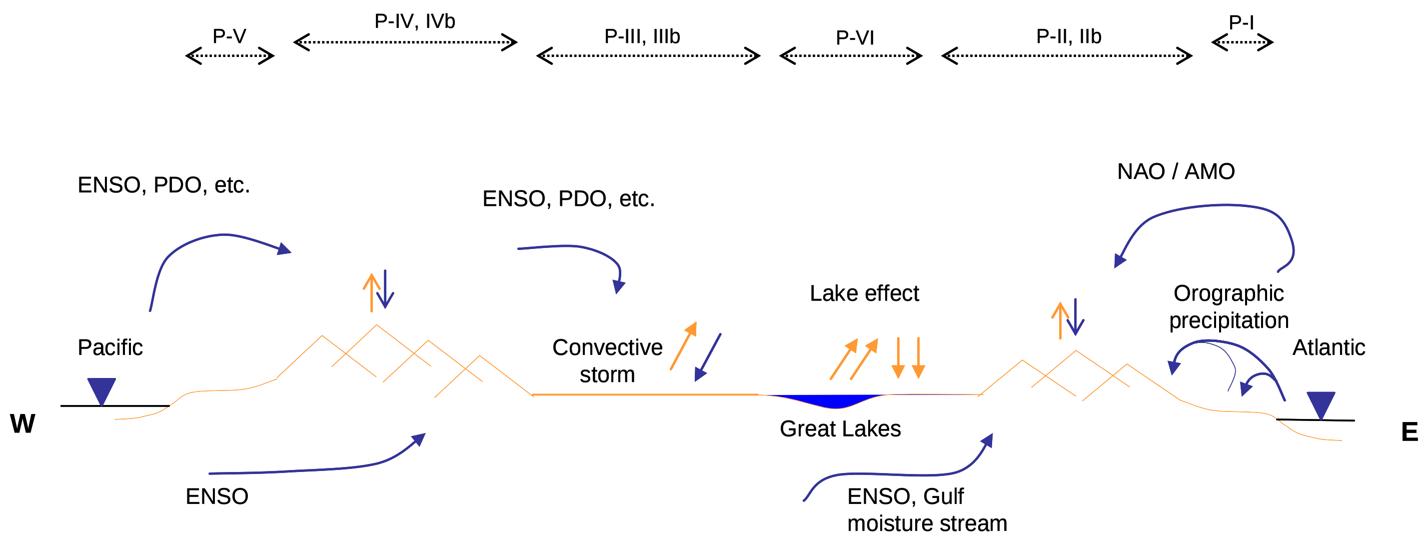

Figure 3.1. Schematic illustration of major climatic systems interacting with local climatic factors producing precipitation characteristics in each of the hydroclimatic provinces. Note: Ocean-originated synoptic climate systems are marked by blue arrow lines, while land and topography-related precipitation is marked by brown arrows.

climate variables further add complexity and variability in temporal and spatial precipitation distributions.

These climate systems operate in different regions of the U.S. (Figure 3.2) and produce periodic variations (e.g., 3-5 year cycle, multi-decadal) in precipitation intensity, water availability, and to some degree, drought occurrence and frequency. A series of climate studies using atmosphere-ocean (A-O) general circulation model (AOGCM) simulations investigated how these A-O interactions will change under future anthropogenic emissions scenarios (IPCC, 2007; IPCC, 2013). As shown in Figure 3.2, the average bias in mountainous western North America is >60% on an annual average basis and nearly 200% during the summer (JJA). The spread of the bias and probability curves are the smallest for the central North American region that has uniform topography and consistent precipitation wavelet spectra. DJF, MAM, JJA, SON are month abbreviations denoting the winter, spring, summer and autumn seasons, respectively.

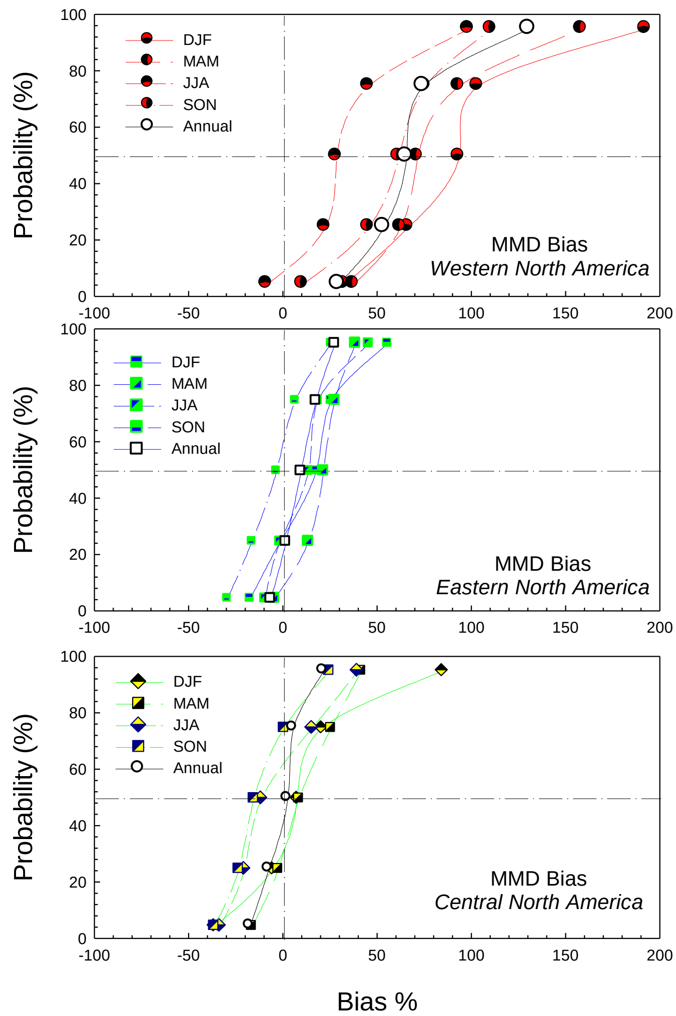

Figure 3.2 Multi-model dataset (MMD) bias compared to observed precipitation (Xie and Arkin, 1997; U.S. EPA, 2014a,b) in control runs (1980-1999) for three North America regions.

In the long term, elevated green-house-gas (GHG) levels are projected to intensify A-O interactions and produce greater impacts on climatic systems such as ENSO. For example, an enhanced ENSO system would further decrease water availability in an expanded area of the U.S. southwest, increase the frequency of high-intensity precipitation in U.S. northeast and Midwest, and reduce snow pack in U.S. northwest while consequently increasing drought prevalence in the region (IPCC, 2007; IPCC, 2013).

3.2.1.2 Regional and local factors

While synoptic precipitation variations respond to larger-scale climate dynamics or climate state (e.g., IPCC, 2007; Barsugli et al., 2009), many precipitation changes tangible to water resources are related to local and regional factors. Examples can be observed in convective precipitation in the Great Plains (Weaver and Nigam, 2007), dynamic uplifting and rain shadows in the interior of South Carolina (Konrad II, 1997; Changnon, 2006), and regional synoptic patterns of short-duration (e.g., 24 hours) precipitation due to orographic uplifting in the coastal region of the state of Washington (Wallis et al., 2007). Yang et al. (2008) showed a localized increase of high-intensity, 75% upper-percentile, 24-hour precipitation in the Lower Mississippi River Basin (LMRB), and attributed it to topographic influence. Details of these findings will be summarized in a companion EPA report (U.S. EPA 2014b).

The IPCC (2007) stated that AOGCM models are of value in representing the general features of future continental precipitation regimes. However, AOGCM projections have substantial uncertainty at local watershed scales. Examples include poor model performance with respect to high altitude orographic precipitation in the Appalachian Mountains (McKenney et al., 2006; Konrad II, 1997), convective precipitation in the Great Plains (Ruiz-Barradas and Nigam, 2005; Higgins et al., 1998), albedo effects of snow, forecast, aerosols, and other local factors (Roesch, 2006; Nijssen et al., 2003), and the timing and spatial distribution of climate systems related to sea surface temperature (SST) anomalies (IPCC, 2007 Chapter 8, and references therein). These difficulties are in part due to insufficient spatial resolution of the AOGCM model grids in fully representing the topographic forcing, high-altitude surface albedo of snow packs as well as other climate mechanisms such as soil moisture contribution, low-level clouds and aerosol radiative forcing.

To improve general circulation model (GCM) predictability, individual climate model runs can be combined into averages. The 21 AOGCM model ensemble, referred to as the multi-model dataset (MMD), hosted at the Program for Climate Model Diagnosis and Intercomparison (PCMDI) has been used to assess future changes in precipitation. The MMD still has significant uncertainties in projection, as shown by the model bias. The model bias is the percentage difference between the GCM calculated precipitation and the observed precipitation data of Xie and Arkin (Xie and Arkin, 1997) for western North America (WNA), eastern North America (ENA) and central North America (CAN). It reflects how GCM simulations are capable of representing the regional and local climate factors. In Figure 3.2, the bias distribution clearly shows that large model over-predictions of 28 to 93% in mean precipitation occur for all four seasons within the WNA model domain. This regional model limitation is also shown by the large spread of probability curves for all four seasons. The discrepancy can be much larger for daily or monthly precipitation at a single location than for the seasonal average over the entire

WNA model domain. Comparatively, the MMD outputs are best for the CAN model domain, with the average model mean bias ranging from 8% to 16%. Less robust are the model predictions with a bias of -4% to 21% in ENA (Figure 3.2), which encompass the Appalachian Mountains and the Northeast U.S. These results, as summarized by the IPCC (IPCC 2007), reflect model inadequacy for a full representation of ENSO, PDO and NAO periodicity and magnitude variations, as well as the Hudson Bay and Canadian Archipelago system, tropical cyclones and landfall precipitation connections to the Labrador-Arctic climatic system in northeastern U.S., snow albedo feedbacks and climatic variations in high-altitude mountain regions.

3.2.1.3 Generalized precipitation changes in regional scales

Given the magnitude of GCM model bias, there have been extensive efforts to improve the reliability of climate projections. Such efforts are important to hydrological applications, including water resource planning for energy and fuel production. Among several approaches for model improvement, dynamic climate downscaling in regional climate modeling (RCM) incorporates regional and local climate factors in climate simulations. However, because of the computational intensity of dynamic RCM simulations, significant, widely applicable breakthroughs or improvements are unlikely to occur over the next 10 to 15 years (Barsugli, 2009).

Another technical approach for future climate projection is statistical downscaling. The GCM output of a future climate state is converted to regional-scale conditions using a statistical converter to correct the GCM bias against known local precipitation records. The bias-corrected RCM results are often used for water resource planning (e.g., large scale applications in the U.S. northwest and California). Statistical analysis of long-duration historical records often allows one to define specific regional and local climate factors that control precipitation variability. The results can further help define statistical downscaling and help predict precipitation and hydrological changes over the next 30 years. One such investigation has been carried out at the EPA for the contiguous U.S., as described below in Section 3.2.2.

There are several generalized trends found in projected precipitation changes due to climate change that can be recognized from the investigations conducted so far. A summary review of climate model simulations can be found within IPCC reports (IPCC 2007, 2013). Below are notable features in the model outputs related to precipitation changes in the U.S.:

- Large degrees of precipitation decreases over 10% are projected for the U.S. southwest, including Arizona, New Mexico, western Texas, Nebraska and Nevada. Snow precipitation will likely change to rainfall, resulting in large decreases in snow pack and consequently stream flow and seasonal variation. The decrease in the flow of the Colorado River, which started in the last century, will continue and intensify in future decades according to work by Woodhouse et al. (Woodhouse, 2006) using tree ring data.
- Continued precipitation decreases and intensified droughts are projected for Florida, Georgia and the neighboring states further north along the Atlantic sea board.
- By contrast, precipitation in the form of increased downpours and flash floods are very likely in the U.S. northeast. Similar trends are likely in the Great Lakes region and the Ohio River valley.

- Changes in seasonal precipitation and forms of precipitation in the U.S. north plains will likely continue. The changes will likely impact the hydrology and pollutant transport of the Mississippi River system (e.g., Scavia, 2003; Jager, 2014). This trend is already evident within Lower Mississippi River hydrological studies (Yang, 2008) that are detailed in the accompanying National Assessment of Water Infrastructure Adaptation report (U.S. EPA, 2014a).

3.2.2 Observed climate changes and their impacts on water availability

3.2.2.1 Changes in historical precipitation

A detailed analysis of historical precipitation records was conducted for 1,207 monitoring stations within the U.S. historical climatological network (USHCN) over the entire contiguous U.S. The investigation was based on a total dataset of 129,288 station-years, or an average record length of 107 years per station. The long time-scales of the datasets were necessary to ensure that historical records were long enough to capture climate variation and climate change. Such datasets can be then used for statistical downscaling and analysis of long-range variation trends.

The historical precipitation frequency, intensity, spatial distributions and their variations through time have been examined by using linear regressions and frequency-domain de-noise operations[10] (Torrence, 1998; Keener, 2010). The frequency and variation pattern analysis led to the delineation of six hydroclimatic areas across the U.S. (Figure 3.3): Florida and the Southeast, the Lower Mississippi – Ohio River valley – New England region (LONE), the Great Plains and Midwest, the Basin-and-Range region, the West Coast and the Great Lakes provinces. In addition to the spectrum analysis, linear regression of the monthly average precipitation against time yielded a rate of change for each station. The obtained slope, α, was further normalized by the precipitation in 1950 at the same location. The normalized precipitation change rate, R (cm/month), was then calculated, and was used to compare the precipitation changes for all stations of various hydroclimatic settings.

Overall, historical precipitation increased slightly to 0.083% per year over the entire contiguous U.S., or 0.079% per year relative to 1950. The change varies by over one order of magnitude among parts of the country. Specifically, each hydroclimatic province has unique precipitation variability and unique long-term changes:

- Province One is located in Florida and the Southeastern U.S. This province has strong decadal and multi-decadal precipitation variability. Its long-term precipitation changes are the smallest among all of the analyzed regions, with a markedly slight historical precipitation decrease of -0.004% per year relative to 1950.
- Province Two consists of two sub-regions: P-II and P-IIb (Figure 3.3). P-IIb covers the lower portion of the LMRB. Precipitation has increased there over the past several decades

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[10] The frequency-domain de-noise operation is a type of wavelet spectrum method for identification of underlying trends in noisy datasets. It is based on frequency variations in datasets to reduce unimportant noise levels. See references cited for more details.

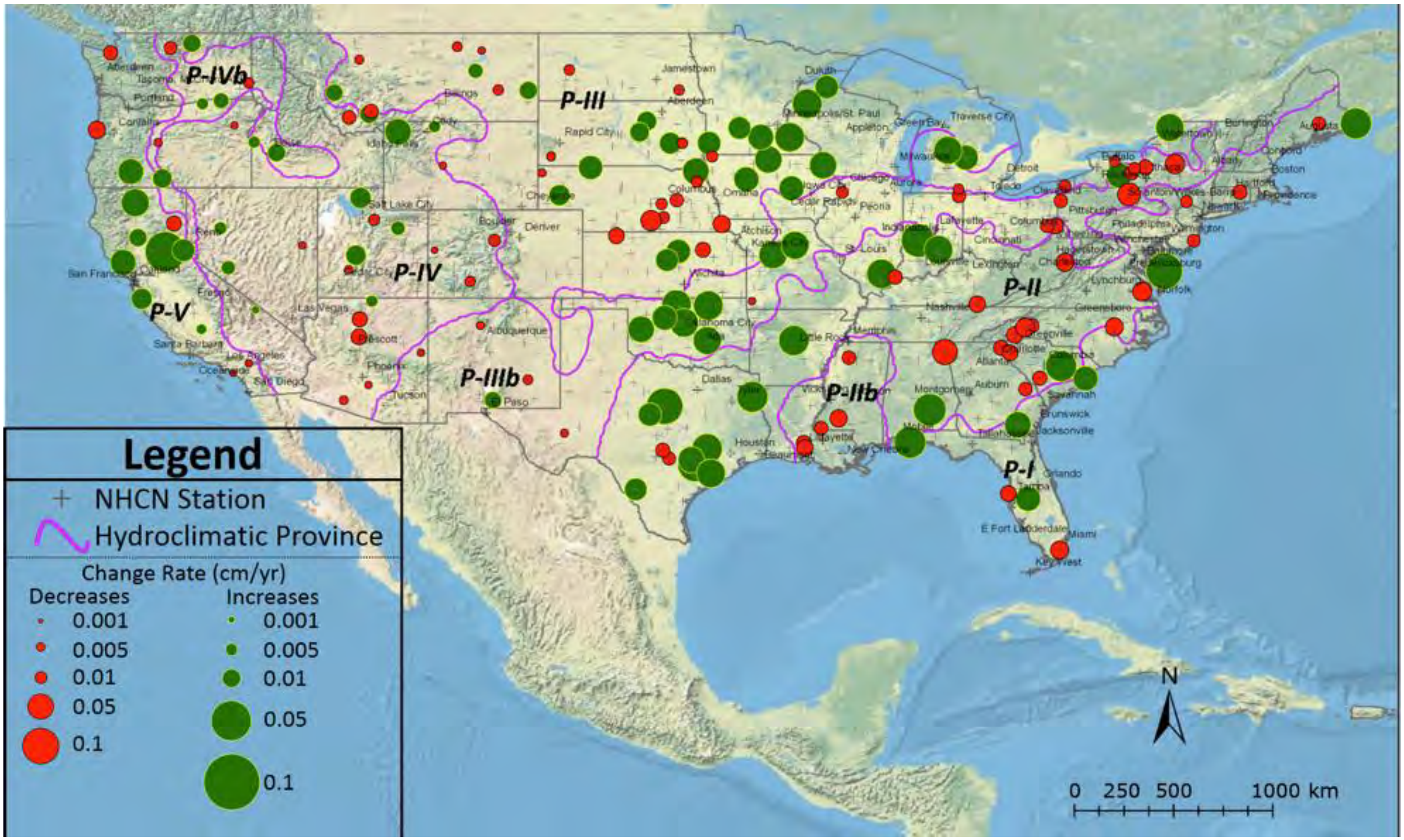

Figure 3.3. Hydroclimatic provinces and extreme precipitation changes in the contiguous U.S. Adopted from U.S. EPA (2014a,b). Note that the spatially consistent large precipitation increases in the 90% percentile are congregated in the Mississippi River valley and northern California Central Basin. Precipitation decreases are primarily in the Great Plains, Basin and Range region, U.S. southwest, the Appalachian mountain area and Florida. All analysis was based upon long-duration climate records.

at an overall rate of 0.121% per year for 90% of the stations. The rest of the P-II region covers much of the U.S. east of the Mississippi River, including the LONE region.

- Precipitation in this area is enhanced by moisture movement from the Gulf of Mexico, and the intensity of precipitation will likely increase as temperatures warm in the future.
- Province Three is a large region that includes the Great Pains and the Midwest (Figure 3.3). Historical precipitation shows characteristics of the ENSO-enhanced three to five year periodic variations with PDO-related decadal variation. In addition to the ENSO and PDO related variability, several regions within Province Three show long-term precipitation increases, possibly as a result of convective precipitation and moisture movement from the Gulf of Mexico. On the contrary, a large region in Province Three centered at the Iowa-Nebraska region has had a persistent decrease in precipitation. Similarly large precipitation decreases have been recorded for the southwest U.S. in the transition zone known as P-IIIb.
- Province Four covers the basins and range region of the U.S. that includes most of the noncoastal western U.S., the Rocky Mountains and adjacent areas (Figure 3.3). Precipitation in the region is affected by PDO teleconnection and topographic forcing, creating local variability. Historically, precipitation has increased in local water bodies such as the Great Salt Lake and along moisture channels such as the Snake River Valley. Other parts of the province have experienced a steady decline in precipitation and persistent drought conditions.

  Woodhouse et al. (2006) conducted a detailed study of the historical river flow in the Colorado River using a tree ring based paleohydrological reconstruction method. The results indicated that river flow decreased by 75% following a preceding peak flow; river flow is currently following a flow-decreasing trajectory.
- Province Five consists of the U.S. west coast region (Figure 3.3), and is distinguished by a persistent decrease in precipitation in the south and an increase in the U.S. northwest in recent decades. Precipitation variability is marked by strong 12 to 15 year cycles, while high-intensity precipitation is consistent with the ENSO cycles of the three to five year time interval. The frequency and intensity of ENSO-related downpours have shown a steady increase in recent years.
- Province Six covers the Great Lakes region, which has the largest rates of precipitation increase since 1950. The rate of long-term increase is 0.13±0.183 $\%yr^{-1}$ ($\bar{m} \pm 1\sigma$), and the trimmed mean is 0.126 $\%yr^{-1}$. Like P-IIb, the province is adjacent to large water bodies.

3.2.2.2 Extreme precipitation changes

As shown in Figure 3.4A, many stations have reported extremely large rates of precipitation decrease and increase. This subset of changes found from within datasets of over a 100-year period is significant as they reflect the underlying causes with respect to climate factors. Furthermore, those within the 90% and 10% population percentile represent the extremely high and the extremely low precipitation within each hydroclimatic province, respectively. The extreme precipitation areas delineated from all datasets are shown in Figure 3.3.

California and U.S. Southwest - Synoptic-scale precipitation extremes can be identified in several large areas in P-IV and P-V (Figure 3.4A). Extreme precipitation in the 90th percentile increased in areas of the Central Basin, northern California, Oregon and the Sierra Nevada. To the southeast, a large rate of precipitation decrease is identified within the 10th percentile distribution of the data. This area, vulnerable to drought occurrence, includes southern California, most of Arizona, western and northern New Mexico, part of Nevada and Utah. In

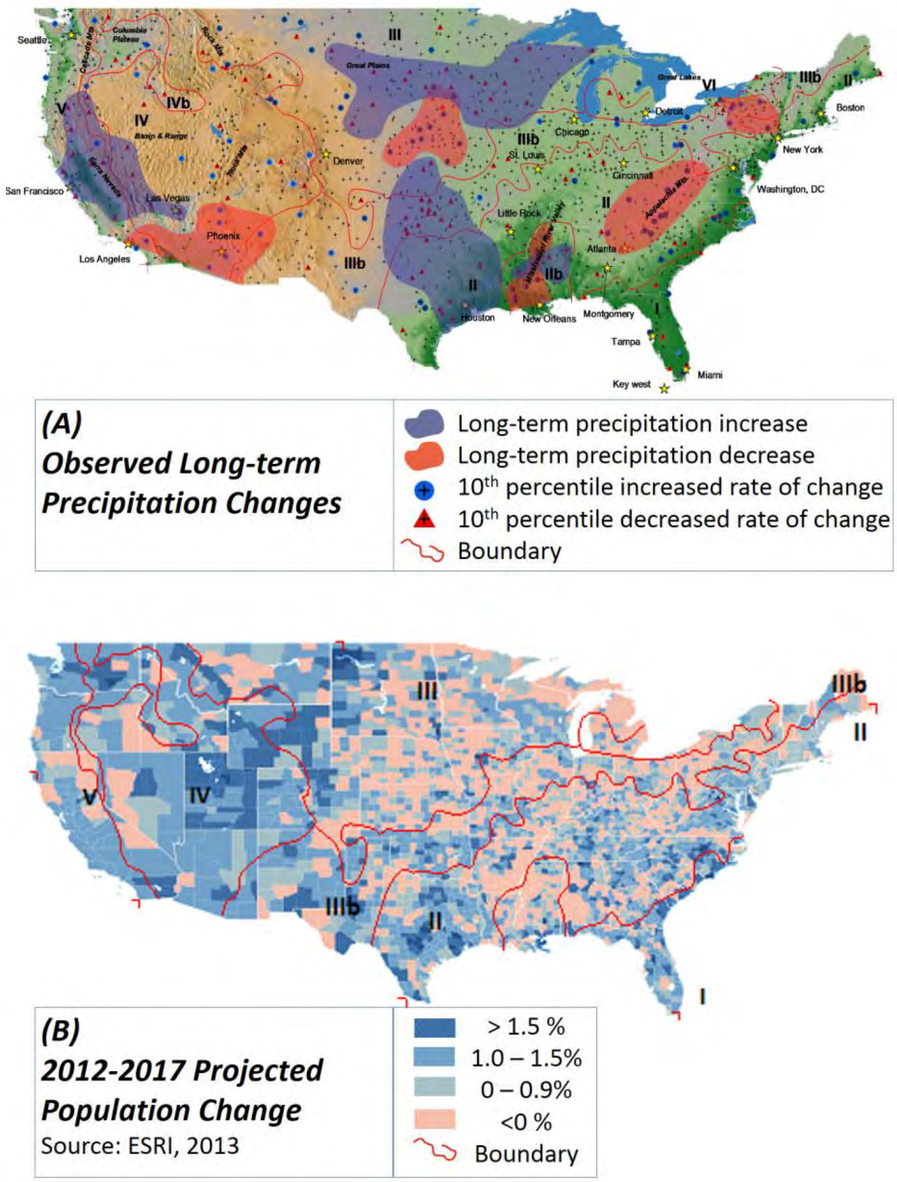

Figure 3.4 Spatial distributions of long-term precipitation changes and population change in the contiguous U.S. (A). Areas of long-term precipitation decrease (red) and increase (blue) delineated from spatial aggregation of changes in Figure 3.3. Detailed information on hydroclimatic provinces is available in a separate EPA report (U.S. EPA, 2014a); (B). The ISRI population data was for 2009-2014 on a county scale. Red lines mark the boundaries of hydroclimatic provinces.

addition, high altitudes stations in the mountain ranges such as the Wasatch Range also fall into the 10th percentile displaying a high rate of precipitation decrease.

Great Plains and Gulf Coast - In P-III and P-II, a large-scale distribution of extreme rates of precipitation change is observed in Texas, Oklahoma, the Great Plains and the Midwest. In Figure 3.4A, the 90th percentile for a high rate of precipitation increase is found in areas extending from the Texas Gulf coast near Houston, and north-northwestward into Oklahoma and central Kansas. The area's northern extension is limited to immediately south of an elevated topography in the Smoky Hills and by the Smoky Hill River. Further to the north, another area of the 90th percentile precipitation increase extends from Lake Superior westward into southern Wisconsin, northern Iowa, South Dakota and northwestern Nebraska (Figure 3.4A). Between the two areas are the stations, mostly in Nebraska, that display high rates of precipitation decrease in the 10th percentile. This area encompasses northern Kansas and eastern Nebraska along the Platte River in Omaha and the surrounding vicinity.

Eastern U.S. of P-II and P-III - The eastern U.S., including the Northeast, only contains climatic stations of regional distribution marked with large rates of precipitation decrease in the 10th percentile (Figure 3.4A). One prominent case is centered within the Appalachian Mountains in the Blue Ridge region of South Carolina and North Carolina, extending to the Appalachian foothills of Tennessee, Kentucky and northern Georgia. To the north in New York, northeastern Pennsylvania and New Jersey, a cluster of stations with the rate of precipitation decrease fall into the 10th percentile. This area includes the Catskill Mountains—a headwater region for water supply for the City of New York. At station NY306774 in Port Jervis (NY) south of the Catskill Mountains, for example, the normalized rate of precipitation change is -0.131% yr^{-1} over the past 120 years. In the Catskill region, Burns et al. conducted a detailed hydrological investigation using statistical analysis of air temperature, precipitation and stream flow measurements (Burns et al., 2007). Their data segment covers the period 1952-2005, for which the analysis clearly showed increased precipitation under a warming local climate.

Florida and Southeast Coast - In P-I, extreme monthly precipitation shows no spatial association. Most stations in either the 90th or 10th percentile range are scattered all over the province (Figure 3.4A). This absence of geographic association over a large area is consistent with the relatively homogeneous topographic terrain of the province (See Figure 3.3), which is affected by climate systems that originate from the Atlantic Ocean and the Gulf of Mexico.

3.2.3 Changes in river flows and river basin hydrology

3.2.3.1 General understanding of river flow changes and water availability

Climate model ensembles such as MMD provide general trends in precipitation changes and their spatial distribution. These results are in agreement with statistical analyses of historical, long-duration hydroclimatic records, while the latter provides more specific information on the regional and local characteristics with quantifiable uncertainties for water resource planning. Overall, likely future changes follow a general trend that regions with drier climates will experience more intensified drought, while the spatial distribution will likely expand and the intensities of precipitation events will likely increase. More specific climate model projections are available from the CMIP5 project[11], and is compiled by the National Oceanic and Atmospheric Administration (NOAA) from sources both within NOAA and from other U.S. Federal agencies[12]. Furthermore, the long-duration hydroclimatic data described in Section 3.2.2 can be used for climate model verification, and in some cases may be useful for local climate model downscaling. More information on model projections and how the information can be used for climate change adaptation planning and design can be found in the accompanying EPA reports on water infrastructure adaptation (U.S. EPA, 2014a,b).

Changes in regional precipitation, and to a lesser extent changes in regional temperatures, occur as a result of climate change. These changes, in turn, lead to changes in regional hydrological cycles, such as stream and river flows and the levels within water reservoirs, and therefore changes in water availability. Resulting changes in water availability can limit the choice of energy and fuel production because of constraints on 1) direct water usage for energy production such as evaporative cooling in thermoelectric power generation, and 2) water requirements for biomass growth within bioenergy production processes such as the production of ethanol and biodiesel transportation fuels. The later sections of this report specifically describe these water-energy relations. With respect to hydrological responses to future climate and precipitation changes, there exists a wealth of literature that includes quantitative analysis in watershed and river basin scales. Examples of the studies conducted by EPA are described in subsections below. General trends are:

- *Colorado River and its river basin in the U.S. southwest* - As precipitation is expected to decrease substantially, a large decrease in river flow is very likely. The hydrological modeling based on the A1B emission scenario (IPCC, 2007) and projected land use changes in the Lower Virgin River Basin (LVRB) shows a likely 35% river flow decrease by 2050. The Lower Virgin River is a large tributary of the Lower Colorado River that provides water inflow into Lake Mead. Because LVRB has similar land use and physiographical properties to the Colorado River basin, projected river flow changes in LVRB are likely indicative of general trends in river flow and, generally, in water availability in the basin.

  This water-poor region will likely experience increasing competition for water allocation to meet environmental requirements for minimum ecological stream flow, often quantified on a basis of a seven day average of 10 year return flows (7Q10). Water withdrawal for municipal usage and agricultural irrigation are among the largest water withdrawals in the U.S. The land use and population changes in the Colorado River basin and the U.S. southwest will further limit water availability for meeting energy production needs. These land use and population changes will be described in further detail in section 3.3.

- *Great Plains and the U.S. northwest* - These large geophysical provinces host several river basins with concentrated power and energy biomass production. These include the Snake River – Columbia River basin and the upper Mississippi river basin. Significant future changes include the seasonality and timing of river flows due to the change of precipitation forms (e.g., snow versus rain), the timing of snow melt during the spring season, and the increased intensity of rainfall precipitation. All these factors can affect water availability.

[11] http://cmip-pcmdi.llnl.gov/cmip5/data_portal.html
[12] www.climate.gov

- *Ohio River basin and lower Mississippi river basin* - River flows in these two river basins are likely to remain stable or increase. The precipitation in the Lower Mississippi River (LMR) region has increased in the past 60 years, leading to an increase of river flows in major LMR tributaries such as the Yazoo river basin in Mississippi, Alabama, Texas and Oklahoma.
- *River systems in Florida and U.S. southeast coastal region* - The river systems of the Florida Peninsula, those in the Atlantic coast of Georgia and South Carolina, and those along the Florida Gold coast are likely to experience declines in base flow. Water availability in the region is likely to decrease as this hydroclimatic province is the only one showing a consistent, decades-long decrease in precipitation.

3.2.3.2 Examples: Stream flow change in Lower Virgin River

The Lower Virgin River (LVR) watershed region has a typical semi-arid climate in the U.S. west. The river flows into Lake Mead at the confluence of the Colorado River. Lake Mead is the second largest human-made freshwater reservoir in the U.S., and is an indispensable source of freshwater supply for millions of people in the American southwest. The lake provides 90% of the freshwater supply for the Las Vegas metropolitan area. Overall, precipitation in the LVR watershed varied with no clear trend for the past 50 years. Water discharge from the LVR watershed and the main stem of the Colorado River has decreased downstream into Lake Mead. The decrease accelerated after 1999, resulting in large decreases in the water volume of Lake Mead (Figure 3.5). The amount of water in Lake Mead in 2010 reached its lowest level since 1940. The largest drop in water volume occurred from 1998 to 2010 (from 30.79 to 13.27 km^3).

Future river flows have been examined by an integrated hydrological simulation that combines land use modeling and climate change for the LVR watershed under future emission storyline IPCC B1 (IPCC, 2007). In this quantitative study, land cover variation of the river basin in 2030 and 2050 are projected using a cellular-automata Markov Chain (CA-MC) land use model. A cell-based hydrological model in high spatial resolutions (Chen et al., 2014) is used to project river flows using future precipitation and land use as input parameters. Model-simulation results clearly suggest large and differential changes in river discharge in the future. There will be different watershed hydrologic responses between summer dry seasons and winter wet seasons, and among the climate and land cover change scenarios. Under the IPCC B1 emission scenario, future temperatures will increase both in summer and in winter. The projected precipitation will increase in summer but decrease in winter. When only future climate change is considered, the projected total discharge of the LVR for the three winter months (December, January and February) would be 6.74 m^3/sec in 2029-2030, and 5.98 m^3/sec in 2049-2050. This represents a decrease of 64.82% and 68.79%, respectively, from the 2009-2010 levels. In summer, except for the month of August, the projected discharge will increase, and the rate of increase will decline in the two decades from 2030-2050 when compared to the preceding two decades.

When the combined effects of climate and land cover changes are considered together, the amount of river discharge will decrease in the winter. The largest decrease may occur in January 2050 by as much as 75.4% (Chen et al., 2014). The river will most likely be drier in winter, and the problem of water shortage will likely be aggravated in the region.

The model projections are consistent with the paleoclimatological investigation results. Woodhouse et al. reconstructed historical flow variation in the upper Colorado River at several locations, including one at Lees Ferry, Arizona, approximately 150 km east of the LVR watershed (Woodhouse, 2006). Their results showed large variability of yearly Colorado River flow in the last 50 years. In the latest cycle prior to 1970, the river flow decreased by 80.5% in approximately 40 years. This rate is comparable to a maximum of 75.4% reduction in LVR discharge that our cell-based model has simulated under climate change conditions of the next 40 years.

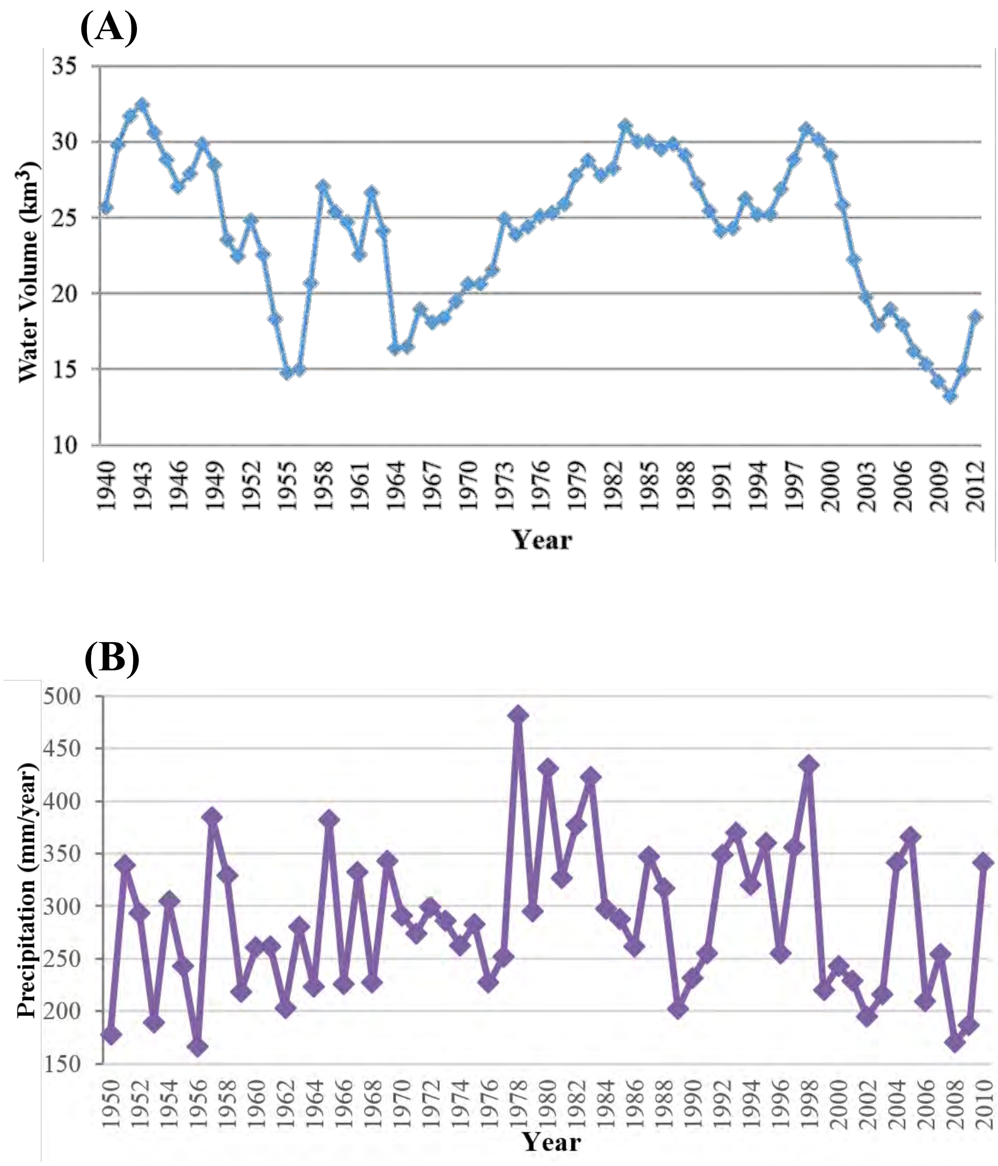

Figure 3.5 Temporal variations of (A) water volume in Lake Mead; (B) annual precipitation in the LVR basin.

3.2.3.3 Examples: Water quality changes in the Little Miami River basin

The Little Miami River (LMR), a major tributary of the Ohio River, originates southeast of Springfield in southwestern Ohio. It flows 169.78 km from Clark County through several steep-sloped, forested gorges to join the Ohio River at its confluence in Hamilton County, near the eastern edge of Cincinnati. Draining an area of 5840 km^2, the watershed covers Clark, Greene, Warren, Clermont and Hamilton Counties, as well as portions of Montgomery, Clinton, Brown, Highland and Madison Counties in Ohio (Tong et al. 2012). Agricultural farm lands and forests are the two largest land use types.

A hydrological simulation conducted by EPA (Tong et al., 2012) evaluated the future stream flow and water quality changes in the LMR through 2050. The simulation is based on land use projections in the region using the CA-MC land use model that also considers population growth as a driving force for urbanization and suburban sprawl. The population for year 2050 was estimated using a geometric growth model, and the population density for each census block group in the study area was calculated. These results were then incorporated into a suitability map for urban areas through the Multi-Criterion Evaluation (MCE) simulation module in GIS (Tong et al., 2012) to produce a population filter, a surrogate depicting the impacts of population growth on land use changes.

The simulation was focused on both changes in river flow and the concentrations of nutrients (e.g., phosphorus and nitrogen). In the LMR watershed, the calibrated model yielded projections for large changes in river flow and water quality for the analyzed precipitation scenarios. Notable conclusions from 2012 EPA/Tong et al. LMR study include):

- The combined climate and land use changes could significantly impact LMR flow. With no climate change, the flow is projected to increase from 23.3 to 41.7 m^3/s, or by 29.09%. In wet and dry seasons, the combined effect on river flow could be an increase of 16.22% to 43.83% and a decrease of 43.92% to 53.08%, respectively.
- Water quality will likely deteriorate in the future. Total phosphorus and total nitrogen could increase in all of the analyzed land use and climate change scenarios. Maximum changes in phosphorus and nitrogen are projected to be 11.99% and 7.22%, respectively.

3.2.3.4 Examples: Mississippi River flow and nutrient loading

The Lower Mississippi River basin (LMRB) covers an 181,600-km^2 area consisting of Louisiana, Mississippi, Arkansas, Missouri, Kentucky and Tennessee. The basin consists of nine sub-basins following its tributaries including the Atchafalaya River, the Arkansas River, the Ouachita River, the Red River, the Yazoo River and the Big Black River. The area, geographically known as the Mississippi Embayment (van Arsdale and Cox, 2007), is characteristic of the low-lying, NNE to SSW trending basin that traces the nearly 1600-km long Lower Mississippi River. The embayment topomorphology has a U-shaped cross-section and gentle slopes along the center of LMR valley. Because of the geophysical characteristics, the small longitudinal hydraulic gradient in the river has caused frequent channel migration, numerous oxbow lake formations and flood occurrences (Smith, 1997).

Comprehensive hydrological studies on precipitation and flood occurrences have shown the prevalence of local precipitation variability in the LMRB, and the synoptic ENSO-related hydroclimatic effects in the form of disruptive meteorological events, river flows and nutrient fluxes into the Gulf of Mexico. Wavelet-reconstructed river flow variations and the time-frequency spectrum[13] (Keener, 2010; Torrence, 1998) exhibit strong perennial flow variations with three to five year short-term, high-frequency periodicity, and two distinct periods of different variability characteristics in the records since 1930s. The three to five year periodicity in river flow is prevalent and characteristic of the ENSO variability reported previously for rivers in North America (George, 2006; Makkeasorn et al., 2008; Qian et al., 2007; Zhang and Schilling, 2006; Hereford et al., 2006).

The embayment along the LMR valley induces strong north and northeast moisture movement from the Gulf of Mexico. As a consequence, increased precipitation over the last several decades and frequent flooding events responding to disruptive meteorological events like hurricanes is likely. This long-term change is expected to intensify from the warm air mass convection driven by southwestern winds because of greater heat content in the atmosphere and stronger A-O interactions as a result of climate change.

Unlike the water stressed Basins-and-Range and Great Plains in the U.S. west, the LMRB is facing different climate change impacts that can potentially place constraints on power and energy biomass production. Water availability is very unlikely a problem, but water quality changes are likely a concern for future planning. High-intensity precipitation and flash floods are known as the leading cause for a high degree of surface water quality variations. Precipitation-induced areal floods (Lecce, 2000; Patterson, 1964) have been reported to be responsible for propagation of water-born biological contaminants (Furey et al., 2007; Muirhead et al., 2004; Few et al., 2004; Barry, 2002; Curriero et al., 2007; Dortch et al., 2008; Borchardt et al., 2004) and high levels of chemical contaminants and nutrients (Donner and Scavia, 2007; Aulenbach et al., 2007). Therefore, nutrient runoff from energy biomass production in agricultural cultivation is particularly problematic because surface water bodies will already be under stress with respect to water quality.

3.3 Implications With Respect to Energy Production

3.3.1 Climate considerations for thermal electric power generation

3.3.1.1 Water availability from mismatched spatial distribution

Water competition for power generation - Thermal electric power generation consumes a large quantity of water (See Chapter 4, and related sections). This water demand may not be met because of changes in precipitation and limited water availability due to climate change. The constraints are particularly acute in the hydroclimatic province P-IV and the southwestern portion of P-IIIb. Figure 3.6 shows the locations of existing coal-fired power plants in relation to the hydroclimatic provinces. It is reported that more thermoelectric power plants are being planned in the Great Plains and the Basins-and-Range region. There are ten existing coal-fired thermoelectric power plants located in the P-IV province along the Colorado River (Figure 3.6). These are all equipped with closed loop cooling systems, consuming water at a combined rate of 100.4 m^3/sec.

[13] The analysis combined both the frequency and time domains

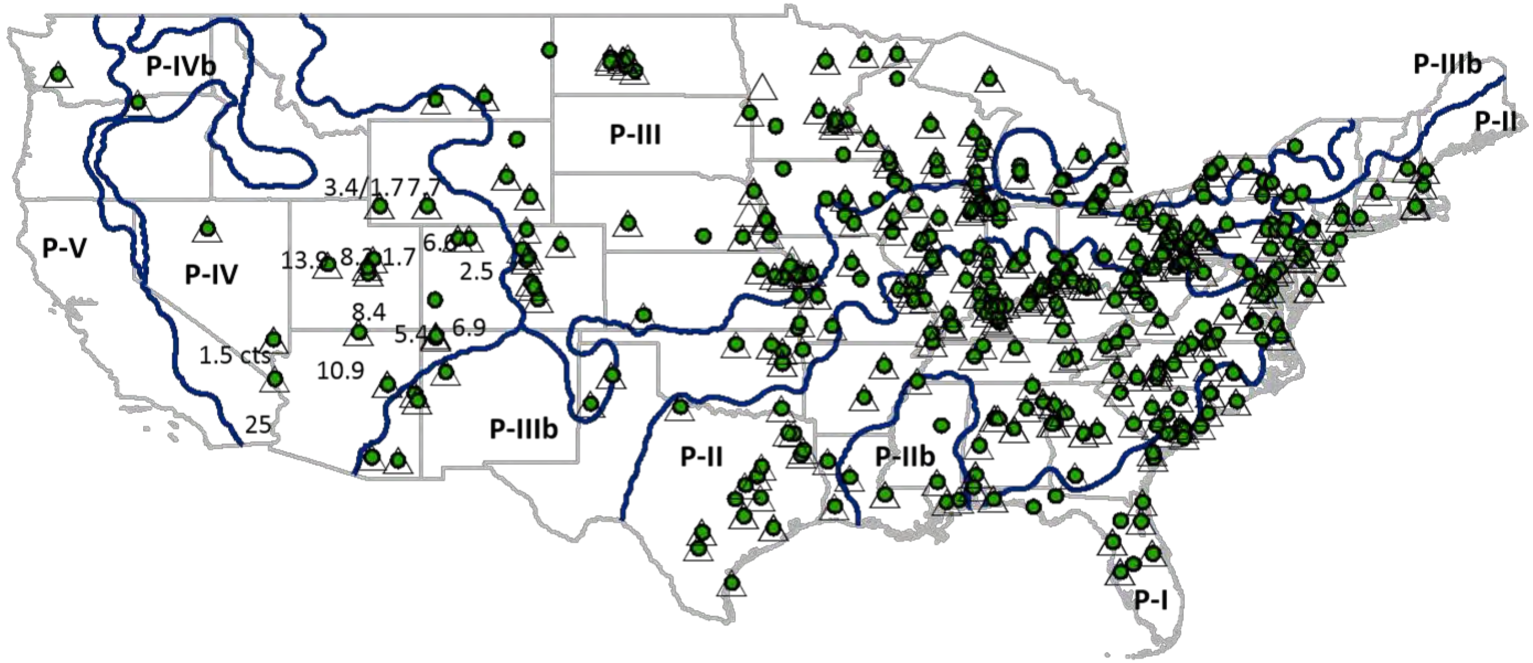

Figure 3.6 Locations of major coal-fired thermoelectric power plants superimposed upon a map of the hydroclimatic provinces of the U.S. Note: Water consumption rates (m^3/sec) are for plants in the Lower Colorado River basin. Data are from IEA 2005 and 2007 surveys (http://www.iea.org/etp/tracking/figures/power/).

The water consumption rate is remarkably large given the decreasing flow in the Colorado River. Water flow in Colorado River decreases along its course through the Basins and Ranges. Downstream at Topock, Arizona, the low river flow is, at most times, less than the water consumption from upstream power plants. Figure 3.7 shows historical river flow measurements from 1917 to 1982 (USGS, 2014). Maximum flows (Q_{max}) during the observation period were ~1000 m^3/sec, and reached nearly 5000 m^3/sec in the summer. On the other hand, the minimum flows (Q_{min}) during the period averaged 171.9 m^3/sec in spring, largely reflecting the snow-melt release of runoff from the river's source water region. In the fall and winter seasons, the average low flow was only 65 m^3/sec, smaller than the 100.4 m^3/sec water consumption rate for upstream power generation. It is clear from this comparison that the ten power plants' consumption amounts to a large fraction of river discharge during low flow conditions.

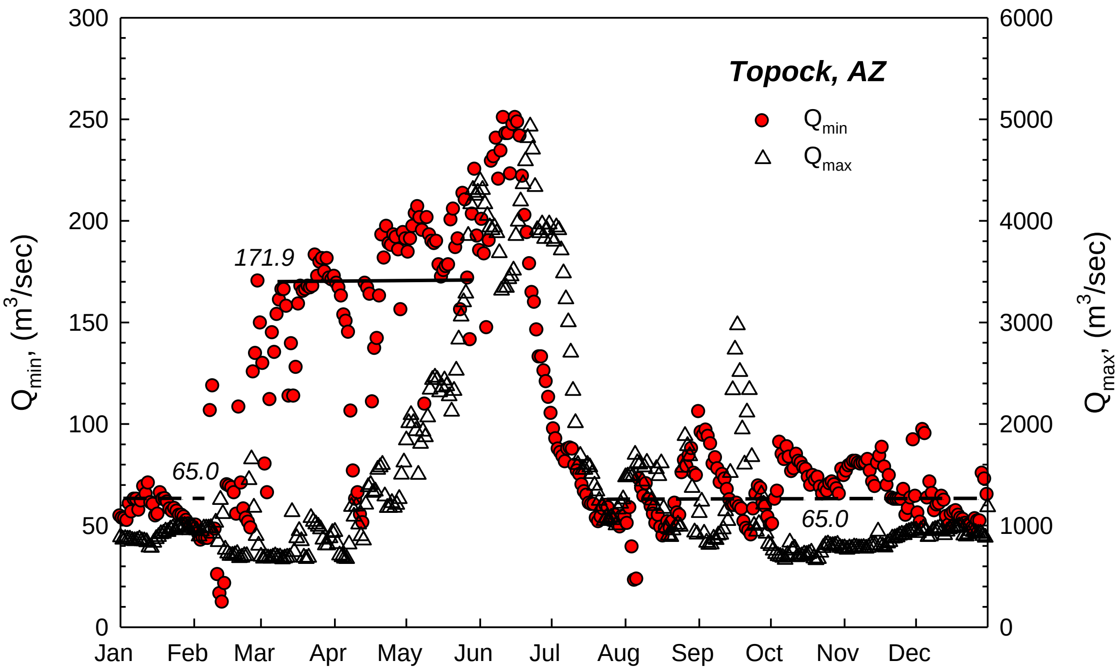

Figure 3.7 Annual flow variation of Colorado River recorded at USGS gage station 942400 at Topock, Arizona. The flow is average of records in a period from 1917 to 1982.

When taking into account climate change projections, the Colorado River flow is expected to decrease rapidly by 2050. Woodhouse et al. concluded from a tree-ring paleohydrological study that the river flow decreased by 80.5% in ~40 years of the latest cycle prior to 1970 (Woodhouse, 2006). Similarly, cell-based hydrological modeling incorporating climate change revealed a decrease of 75.4% in LVR discharge into the Colorado River over the next 40 years.

The strong competition from energy production implicates water availability as a pressing issue for future energy production planning. Similar analyses for other parts of the country are needed to assess the potential impacts of changing water availability on water usage and consumption in thermoelectric power plants. As shown in Figure 3.5, most coal-fired power plants are located in the water-rich Ohio River basin and Upper Mississippi River basin. Coal-fired power generation in other regions are also vulnerable to climate changes. These areas include Florida and the coastal region of Georgia in P-I (Figure 3.6).

In the western coast P-V and P-IVb hydroclimatic provinces, 2007 IEA data shows only two coal-fired power plants. The power plants in these regions have been converted to natural gas, and are therefore not shown in Figure 3.6. As discussed later in this report, natural gas power plants tend to have smaller water footprints than their coal-fired counterparts. Even with a small water footprint, however, water impacts on southern California cannot be neglected because of the expected persistent decrease in future precipitation in the region.

Competition for water - Additional stress on water availability comes from population changes and regulation-mandated minimum ecological stream flows. These two factors compete with water usage for thermoelectric power plants.

In the last five years (2009-2014), the U.S. population has witnessed spatial redistribution (Figure 3.4b). The largest population increase occurred in the water-poor regions of P-IV and P-V, with projected precipitation decreases in the future due to climate change. In Florida and further to the north in the metropolitan areas of Atlanta, Washington, D.C., and New York City, the population has also increased markedly. These are areas within the water poor P-I hydroclimatic province, or areas of extreme precipitation decrease.

In Figure 3.4b, it is clear that the changes in precipitation and population are mismatched with respect to water availability in the future. Several regions where precipitation has long decreased, and will likely continue to decrease, host the largest population growth. Such mismatch is particularly acute in the Lower Colorado River basin of the U.S. southwest, southern California and the central Appalachian regions from Atlanta to New York. Population growth in these regions can result in greater demands for both water and energy, and both can further stress the local water resources unless long-distance electric power transmission and water conveyance are available at the expense of further energy consumption.

Ecological flow is the other competing factor for water, and is placing constraints on thermoelectric power generation, particularly for water-poor regions under likely future climate scenarios. For example, large decreases in average stream flow were projected in the Lower Virgin River of the Colorado River basin, and also in the Little Miami River basin of the Ohio River valley (See Section 3.2.3). Similar reductions in river flows have also been projected for the U.S. northwest region. The decrease in snow pack at high altitudes has been found responsible for decreasing river base flows, and consequently, the river flows diverted for power generation year-round become vulnerable.

3.3.2 Carrying capacity for thermal pollution and nutrient loading

The most direct impacts of the present and future changes in water availability are made on the ability of power plants to discharge cooling water and other process water into surface water (e.g., rivers, streams and lakes) without violation of National Pollutant Discharge Elimination System (NPDES) under the CWA. Similarly, energy production operations, such as hydraulic fracturing for natural gas, may be constrained by reduced flow and assimilation capacity of receiving streams under future climatic conditions.

Under Section 305 of the CWA, EPA's NPDES and the Total Maximum Daily Load (TMDL) programs set up thresholds for thermal and nutrient loading into a segment of U.S. water. In streams and rivers, this threshold is based on 7Q10 stream flows close to the base flow of a river or stream. As described earlier in Section 3.2.3, there are many watersheds and waterways that will very likely experience a flow reduction, nutrient loading increase or both. The combination can make the water discharge from power and energy plants problematic in the future. Considering this likelihood, EPA is conducting research and rule-making analyses on the potential of incorporating climate change effects into water discharge programs.

3.3.3 Implications for energy biomass production

Energy biomass production for transportation biofuels has its own challenges with respect to the water-energy nexus that differ somewhat from the challenges of thermo-electric power generation. Cultivation of biomass crops is land- and water-dependent, while biofuel production tends to be located in geographic proximity to biomass production. Biomass crop cultivation is concentrated in the Great Plains and the Upper Mississippi River basin. This spatial association is a basic consideration in evaluating climate change effects on the sustainability of biofuels production.

Water usage in biomass cultivation has been investigated by EPA using MARKAL modeling (Dodder, 2011; Dodder, 2014). A separate study of the water needs within this report includes water demand from both biomass cultivation and bioenergy production. The largest water consumption rates for biofuel production are located in Nebraska, Kansas, Missouri, Arkansas and Mississippi. Similar but more detailed analyses and conclusions were reported by Sandia National Laboratory (Tidwell et al., 2011).

Compared to the precipitation changes in Figure 3.4A, the biomass cultivation areas in two Great Plains states (NE and KS) are located in a region of long-term precipitation decrease. In this region, the productive artesian Ogallala aquifer has long been used for agricultural irrigation (Sophocleous and Marriam, 2012; Tidwell et al., 2011). Precipitation in the aquifer recharging area in the Rocky Mountains (CO and WY) has been decreasing (See Figure 3.3). As a result, the groundwater level has experienced rapid decline. This water availability stress is likely to worsen in the future. Areal precipitation will very likely decrease, while water loss from crop irrigation will increase along with increased biomass production. For these likely future conditions, the water constraints on bioenergy production have not been investigated according to the data and information examined by this study.

3.3.4 Non-point source nutrients in biomass production

Crop irrigation methods common in the Great Plains and the U.S. Midwest are known to release nutrients, mainly nitrogen and phosphorus, into water and sediments by non-point source pollution (e.g., Cunha, 2014; Yang, 2008, and references therein). Increased biomass cultivation for biofuels production is expected to increase nutrients released from agricultural fields. Jager et al. demonstrated the linkage of energy crop production to river water quality deterioration within a major Lower Mississippi River tributary (Jager, 2014).

As described in preceding Section 3.2.3.4, the LMR flows and nutrient loadings varied in relation to different climate systems. It is known that nutrient loading from LMR contributes to severe nutrient enrichment and hypoxia in the Gulf of Mexico (Scavia, 2003). From this review and analysis, biomass cultivation for biofuels will further increase nutrient loads contributing not only to nutrient levels in the Mississippi River system, but hypoxia in the Gulf of Mexico.

3.4 Adaptation Potential and Conclusion

In this chapter, the impacts of climate change on water resources were discussed in the context of future energy and transportation fuel production. It provided a brief overview of attributes related to climate and population changes and the degree of their impacts on water availability for future energy production. It is noteworthy that the impacts on energy production are multi-dimensional and affect not only current energy production, but also future energy choices and overall makeup. A comprehensive investigation on the energy-water nexus can be found within recent Department of Energy reports (Tidwell, 2011; DOE, 2014).

The review and analysis described herein show that there are substantial, regional climate change impacts upon precipitation resulting in critical anticipated effects on water availability in the contiguous U.S. Thermoelectric power generation and biomass cultivation for biofuels will further stress water availability, particularly in specific regions. This effect is expressed in the form of water consumption from limited water resources and from competition between energy production, domestic consumption and ecological flow in rivers and streams. Furthermore, water availability also limits potential water discharge from power plants into streams and rivers. Thermal and nutrient pollution from production water discharge will likely be a concern with regards to CWA regulations and thus may potentially affect the sustainability of thermoelectric power and biofuels production.

It was found from this review and analysis that climate change effects on water availability are region and location specific. These effects are further amplified by changes in watershed hydrology and by population and land use changes. Therefore, adaptation requires consideration of local and regional conditions for conducting energy production planning and analysis.

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4 Water Impacts from Coal-Fired Electric Power Plants

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4.1 Introduction

Coal is the most commonly used fossil fuel for power generation, accounting for approximately 37% of the total electricity produced in the U.S. in 2012 (EIA, 2014a). The U.S. electric power sector consumed approximately 232 million short tons of coal in the first quarter of 2014 (EIA, 2014b). Coal consumption by the electricity power sector in the U.S. is projected to decrease from 45% in 2010 to approximately 35% in 2040, with a corresponding decrease in electricity generation from 317GW in 2010 to a projected capacity of 278GW in 2040, mainly because of the need to meet emission control requirements (EIA, 2014c).

Generating electricity in coal-fired electric power plants involves mining coal, cleaning or washing the coal to remove impurities, transporting the coal to the power plants and burning the coal in power plants to produce steam, which is then run through a steam turbine to generate electricity. Once energy from the steam is recovered, the steam is cooled and condensed back to water, while other waste products from the combustion process, including bottom ash, fly ash and flue gas, is prepared for disposal. In this chapter, water usage in each of these processes and their impact on water is briefly described.

4.2 Water Impacts from Coal Mining and Processing

The majority of the coal produced in the U.S. comes from Wyoming (41%), West Virginia (12%), Kentucky (10%) and Pennsylvania (5%). Coal is obtained through underground mining or through surface mining techniques such as open pit or open top, high wall or strip mining (NMA, 2012). Water is typically not used during coal mining operations. However, water may flow into mines from groundwater seepages, surface water intrusion or precipitation, which then dissolves organics or inorganics that are present in the mines, and results in water that is acidic and has elevated levels of total dissolved solids (TDS), iron, aluminum, sulfate and other dissolved metal ions (DOE, 2009). In addition, water that contains elevated TDS may also drain from active and inactive mines into surface water, ground water or other water bodies. Depending on the nature of the ore body and the geology of the mining site, water from active, inactive or abandoned coal mines, often referred to as coal mine drainage (CMD) or mining impacted water (MIW), often contains significant concentrations of metals (such as aluminum, arsenic, boron, cadmium, calcium, chromium, cobalt, copper, dysprosium, gadolinium, germanium, iron, lanthanum, lead, magnesium, manganese, nickel, potassium, scandium, silica, samarium, sodium, titanium, yttrium and zinc), oxyanions (such as chromate and arsenites) and salts (such as chloride, nitrates and sulfate) (U.S. EPA, 2013). This water, which can have TDS that can vary from very low (<200 mg/L TDS) to very high (>500,000 mg/L TDS), has to be

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treated to meet certain water quality standards (typically, 250 or 500 mg/L TDS) before it can be further treated or discharged into receiving water bodies such as rivers or streams.

Multiple treatment technologies, usually classified as active or passive, are available for the removal of TDS from CMD. Examples of passive treatment technologies, which typically use natural processes to treat contaminated water, include lagoons, aerobic and anaerobic wetlands, limestone ponds and drains, and diversion wells. Examples of active treatment technologies, which typically require continuous input of chemicals or energy to treat the water, include aeration tanks, neutralization ponds, evaporation, ion exchange, distillation, electrodialysis, filtration and adsorption. Many of these techniques often use energy and water, or impact water in some way (e.g., reverse osmosis typically purifies approximately 80% of the waste stream, while the remaining 20% is concentrated brine that has to be disposed). A discussion of these impacts is beyond the scope of this report.

Mined coal is typically cleaned or washed at the mining site or at some intermediate facility to remove impurities before being transported to power plants. Washing coal facilitates waste material removal from the mined coal, which, in addition to lowering transportation costs, can lower its ash content when combusted in power plants. Typically, coal is washed using density or gravity separation methods that may or may not use water. Once coal is separated, water is removed by passing the slurry through dewatering screens, filters, centrifuges or thickeners, and the recovered water (blackwater) is treated and reused. The amount of water required for cleaning coal depends on the type of coal, the amount of impurities that are present, and its intended use, among other factors. Currently, there is no information in the literature on the amounts of water used for density separation, or the amount of reusable water that is recovered from blackwater. However, the U.S. Department of Energy estimates that approximately 70 – 260 million gallons of water per day is used for coal mining, including the water used for washing coal and cooling drilling equipment (DOE, 2006). After washing, most coal is transported to power plants by truck, rail or barges. In a few cases, however, finely ground coal is transported via pipelines as a slurry, which involves the use of large amounts of water. Meldrum et al. estimates that transportation of coal via pipelines involves the use of hundreds of gallons of water per megawatt-hour (MWh) of electricity produced (Meldrum, 2013).

4.3 Water Impacts from Thermoelectric Power Systems

4.3.1 Steam turbines

The amount of water a thermoelectric power plant requires can be significant. Thermoelectric generation relies on the use of a fuel source to convert water into steam, which is then transferred to a turbine-generator where electricity is produced. The steam exhausted from the turbine is then passed to a condenser to remove the remaining heat, and the water is returned to the boiler (Miller, 2010). The condenser is usually a shell and tube heat exchanger through which cooling water runs to cool the steam passed in the shell. The cooling water is returned to a cooling distribution basin to eject the heat into the atmosphere. In cases where cooling water towers are used, the heat is transferred from the water in the tower by means of evaporation and convection mechanisms, and the water is sent back to the condenser in a continuous circuit (Kröger, 2004). Cooling water mass flow rate requirements can reach values ≥50 times the steam mass flow rates depending on the allowable temperature rise of the water (DOE, 2010).

Conversion of thermal to electrical energy relies on the use of the Rankine cycle. In the Rankine cycle, high pressure steam is produced in a boiler and a superheater is used to further increase the steam pressure. In the condenser of the turbine, the steam is condensed to create a vacuum pressure. The difference between the high pressure steam and the condensed steam creates the driving force for energy conversion. Essentially, the steam is sped up in the turbine due to the pressure difference between the superheater and the condenser (Mortensen, 2009; Prisyazhniuk, 2006; Perry et al., 1998). The low pressure achieved in the condenser is therefore critical to avoid increased backpressure, and thus, a decrease in process efficiency. The low pressures at the exit of the turbine are achieved by the use of cooling water (Mortensen, 2009). The process efficiency can be increased by increasing the steam pressure and temperature within the boiler, leading to plant operations under supercritical (>3200 psi, >1000 ºF) or ultra-supercritical (>3500 psi, > 1100 ºF) conditions. Increases in plant efficiency by increasing temperature and pressure can have a significant effect on water consumption, and it has been estimated that the water volume used by supercritical plants is about 13 percent less than that by subcritical plants (<2400 psi, <1000 ºF). The lower steam pressure in the subcritical plants translates into less energy transferred from the boiler to the turbine; therefore, a higher steam flow, and thus more cooling water, is required to generate the same amount of electricity (DOE, 2010).

4.3.2 Cooling tower operations

Cooling water is used to cool the steam and condense it back into water before it can be sent to the furnace to produce steam. The heat acquired by the cooling water is transferred to the atmosphere or a receiving water body through heat rejection systems such as cooling towers, which can be classified into two main types: wet and dry. In the U.S. electric power generation industry, wet-cooling systems are the most common type, and can be designed as once-through or recirculating systems; the former have higher water withdrawal and the latter have higher water consumption. Cooling systems can also be designed to either freshwater or saline water. Due to regulations regarding water discharge temperatures, once-through cooling systems are no longer being built, and closed-loop recirculating heat rejection systems are the most commonly used systems in the U.S. Among these, cooling ponds or lakes are typically associated with older plants, whereas wet cooling towers are more common in newer power plants. As of 2012, approximately 40% of coal plants in the U.S. used wet-recirculating cooling towers, while 53% used once-through cooling towers (UCS, 2014a). Smart and Aspinall (2009) estimate that a typical conventional coal-fired power plant withdraws between 20,000 – 50,000 gallons of water/MWh and 500 – 1,200 gallons of water/MWh for once-through and recirculating cooling systems, respectively. Their estimates for water consumed were between 100 – 317 gal/MWh and 480 – 1,100 gal/MWh for the two systems, respectively.

4.3.2.1 Wet cooling towers

Wet cooling towers are direct contact heat exchangers. Warm water comes into contact with relatively dry air, and energy is transferred by means of sensible heat loss to the air and latent heat loss with the evaporated water. The greater the water-air contact area and the longer the residence time, the greater the heat transfer (Stultz and Kitto, 1992). Depending on the mechanism of air flow in the tower, wet cooling towers can be subdivided into natural draft or induced draft depending on whether mechanical fans are used to move the air inside the tower (Miller, 2010).

Even though wet cooling towers are among the most energy-efficient and cost-effective technologies for rejecting waste heat, they also require high water volumes. Water is lost in cooling towers by means of drift, evaporation, and blowdown. Drift is a consequence of the tight contact between the air flow and the water flow which produces droplets or mist, creating a water loss that can range from 0.001% to 0.3% of tower flow rate, depending on the quality of drift reducers or mist eliminators (Sovocool, 2008; Aquaprox, 2009). Additionally, it has been estimated that 1% of the tower flow rate is evaporated for every 10°F drop in temperature (Sovocool 2008; Perry et al., 1998). Due to water evaporation, the concentration of TDS and other particulates increases and generates conditions that contribute to scaling, corrosion and biofouling. To maintain water quality, a fraction of the water is continuously removed from the circuit in the form of blowdown and make-up water is introduced to sustain the tower's flow rate (Sovocool, 2008; Aquaprox, 2009). A parameter known as cycles of concentration determines the amount of blowdown required for a specific cooling system. The cycles of concentration are the ratio of dissolved solids in the circulating water to that in the make-up water. An increase in the cycles of concentration causes a decrease in the volume of blowdown and make-up water; therefore, water savings can be associated with elevating this parameter (Sovocool, 2008; Aquaprox, 2009).

4.3.2.2 Dry cooling systems

Dry cooling systems eliminate evaporation losses due to the use of convective heat as the cooling mechanism, and can be classified as direct or indirect dry cooling systems. In direct dry cooling systems, also known as air-cooled steam condensers, the heat rejected from the steam is absorbed in the form of sensible heat gain in the ambient air (Stultz and Kitto, 1992). Indirect dry cooling systems operate with a conventional condenser that uses cooling water to condense the steam turbine exhaust; however, the heat is transferred from the cooling water to the ambient air through a closed, air-cooled heat exchanger. The dry-cooling towers operate on the basis of sensible heat transfer by the use of dry surface coil sections, where there is no direct contact between the air and water, thus eliminating evaporation (Hensley, 2009). Dry cooling systems typically result in significant water savings by eliminating water losses due to evaporation; however, these systems are not as efficient at rejecting heat, which lowers the process efficiency. In addition, the process efficiency is highly dependent on ambient air temperatures.

4.3.3 Bottom ash

Coal contains non-combustible residue, which at the end of the combustion cycle in a power plant's furnace, is collected in a water-filled hopper at the bottom of the furnace. Bottom ash typically consists of 20% of the unburned material. The remaining 80% of the unburned material is captured in particulate control devices as fly ash. The role of the water-filled hopper is to quench and store the hot ash. Crushers then crush the big particles into small pieces, after which the slurry is pumped into an ash disposal pond or it is dewatered and shipped for disposal. More modern systems adopt a continuous heavy duty chain conveyor belt that is submerged in water below the furnace. The bottom ash is quenched as it falls from the furnace, and the wet ash is removed continuously up a dewatering slope, after which the ash is discharged into a storage silo. In all cases, the water that comes into contact with bottom ash typically has the same characteristics of CMD, and has to be treated to remove TDS and heavy metals before it can be disposed or reused.

4.3.4 Flue gas desulfurization

After coal combustion in a furnace, exhaust gases and fly ash are released into a flue, after which the gas is treated prior to being released into the atmosphere via a smoke stack. In addition to fly ash, flue gas typically contains nitrogen from the air used for combustion, carbon dioxide, excess oxygen, water vapor, particulate matter, carbon monoxide, nitrous oxides, and sulfur oxides. Flue gas is typically treated with scrubbers and other chemical processes to remove the pollutants prior to discharge into the atmosphere.

Flue Gas Desulfurization (FGD) units are used to reduce SO_2 emissions, and are significant contributors to the wastewater discharge emanating from coal-fired power plants. Concerns have been raised about their use due to the volume of water required and the presence and quantity of pollutants in the generated wastewater. The use of pollution control equipment in power plants typically produce approximately 200,000 tons of FGD wastewater per year for a 500 MW power plant (UCS, 2014b). Generally, the pollutants present in FGD wastewater include chlorides, mercury, arsenic, boron, aluminum, copper, selenium, and other toxic metals and metalloids, as well as dissolved and suspended solids. Information on FGD technology, its wastewater composition, the most widely applied FGD wastewater treatment technologies, and several alternative technologies that might be of potential interest is presented in the Appendix to this chapter.

4.3.5 Particulate matter

Electrostatic precipitation technology has been widely used to control particulate matter in power plant operations. For a long time, dry electrostatic precipitators (ESPs), used as particulate control devices for industrial gas streams, offered removal efficiencies exceeding 99%, easy operation and reliability; however, the challenges for controlling air pollution in some industrial applications have surpassed the capabilities of these devices (Bayless et al. 2004; Khang et al., 2008). One of the issues associated with dry ESPs is that the charging mechanism limits the size of particles to a range of 0.1 to 2.0 μm, reducing the collection efficiency. This is due to the lower corona power exerted as a consequence of the resistivity of the ash layer accumulated in the collecting surfaces. Also, re-entrainment losses due to rapping[17] result in the non-desired emission of fine particles. Moreover, because aerosol formation does not occur due to high operation temperatures, the removal of acid aerosols is not achieved in dry precipitators (Bayless et al., 2004; Khang et al., 2008)

Wet precipitators (wESPs) have exhibited high collection efficiencies for fine particulates, due to the avoidance of back corona and re-entrainment losses. In wESPs, a water film flows down the walls of the collecting electrodes, where the high degree of adhesion between the water and the collected particles prevent re-entrainment from occurring. Back corona is prevented because flowing water constantly washes out the resistive ash. The collection of acid gases is also enhanced due to the lower operation temperatures that lead to acid condensation and acid aerosol formation (Bayless et al., 2004; Khang et al., 2008). Even though there are clear advantages for the use of wet precipitators, their use at large-scale coal-fired power plants is still under development. The high particulate loads in the flue gas potentially lead to the formation of dry spots in the collection surfaces, which reduces the collection efficiency.

[17] Rapping involves imparting a physical force into an ESP collector plate or discharge electrode in order to discharge deposits.

The transport and disposal of the particulate-saturated water flowing out of the ESPs creates a challenge as well. As a result, wet precipitation is generally recommended to be used downstream of other particulate collection devices (Bayless et al., 2004; Khang et al., 2008).

4.4 Water Reuse and Conservation Potential

Electricity demand is expected to increase throughout the U.S. Coal-fired power plants are expected to remain the single largest source among all sources of electricity production in the U.S. (EIA, 2013), though coal's share of electricity production is less than 50% of total electricity generated in the U.S. and continues to decline. Moreover, populations are projected to rapidly increase in many areas where freshwater availability is severely limited. Consequently, industries and government are searching for ways to reduce freshwater consumption at coal-fired power plants (DOE, 2010). Several approaches are under investigation in the U.S. and around the world to address challenging water demand issues (DOE, 2010). These approaches can be classified into direct or indirect, depending on whether their implementation's main purpose is to directly reduce freshwater consumption or to indirectly contribute to more sustainable water usage (DOE, 2010). A brief review of research projects in the U.S., and some of the solutions being implemented outside the U.S., are discussed below.

4.4.1 Advanced cooling technologies

In the U.S., the Department of Energy (DOE) through the National Energy Technology Laboratory (NETL) has been conducting research and development on new water-energy technologies in the following areas: advanced cooling technologies, water reuse and recovery, use of non-traditional sources for process and cooling water, and advanced water treatment and detection technologies (EIA, 2011).

Advanced cooling technologies include solutions designed to improve performance and reduce costs associated with wet, dry, and hybrid cooling systems (Carney et al., 2014). Developing technologies and strategies to minimize evaporative water losses and reduce the water blowdown requirements that result from these losses is of primary importance. For instance, some of the current research is considering the implementation of condensing modules within the cooling towers (Air2Air® by SPX Cooling Technologies, Inc.), and the application of filtration methods to prevent scaling and increase the cycles of concentration (Pulsed Electrical Fields and Pulse Spark Discharges for Advanced Cooling by Drexel University) (SPX Cooling Technologies, Inc., 2008; Carney et al., 2014).

Outside the NETL water-energy program, much effort has been put into the design of hybrid and dry cooling systems (Wurtz and Nagel, 2010; Schimmoller, 2007). Methods to reduce water consumption in coal-fired power plants include the installation of an ice thermal storage (ITS) system to cool the intake-air to gas turbines, (ITS Technology by University of Pittsburgh) and the use of an air cooled condenser (ACC)—a dry cooling technology (ACC by SPX Cooling Technologies, Inc.) (Mortensen, 2009).

The water reuse and recovery component of the NETL water-energy program focuses on the potential use of power plant cooling water and its associated waste heat. A study at Lehigh University proposes the use of the hot cooling water returned from the condenser to heat ambient air that will later be used to dry the coal. The evaporation losses in the cooling tower are minimized due to the reduction in temperature of the return cooling water. Also, by drying the coal prior to combustion, the plant heat rate is improved, and thus, the overall air emissions can be reduced (Carney et al., 2014). Other projects promoted by Great River Energy make use of the coal drying method to enhance the cycle efficiency through coal heat rate improvements, and as a consequence, cooling water requirements and emissions of CO_2, NOx, SO_2, Hg and particulate matter per unit of energy produced are reduced (DOE, 2010).

The last component of the NETL water-energy program deals with the potential use of non-traditional sources of process and cooling water. For instance, researchers at the University of Pittsburgh and Carnegie Mellon University are identifying a variety of impaired waters for cooling water make-up and assessing secondary treated municipal wastewater, passively treated coal mine drainage and ash pond effluent. Researchers from West Virginia University, in partnership with the Water Research Institute and the National Mine Reclamation Center, have focused on evaluating the technical and economic feasibility of using water from abandoned underground coal mines. EPRI has been evaluating the feasibility of using produced water to meet make-up cooling water requirements (EPRI, 2007). Furthermore, the Nalco Company, the Argonne National Laboratory, Clemson University, and GE Global Research are considering the development of water treatment technologies to facilitate the use of impaired waters in cooling towers (Carney et al., 2014; DOE, 2010).

Outside of the U.S., approaches for reducing freshwater consumption in coal-fired power plants range from fuel enhancement and plant efficiency improvements to the use of dry cooling systems, desalination, and the reuse and recycling of wastewater. Countries facing severe water shortages such as China, Australia, South Africa, and India are also the countries with the highest percentages of electricity generated by coal. In these countries, efficiency improvements and plant retrofits are used as an indirect method for reducing water consumption. The primary motivation for increasing plant efficiency in these countries is the need to reduce carbon emissions in response to climate change. In addition, increasing electricity demand in some highly populated countries such as China and India has exposed the need for larger and more efficient plants (DOE, 2010). Many countries have established policies encouraging or mandating direct and/or indirect water reduction. China's energy strategy plan specifies that in order to optimize production, they must promote the growth of large-scale and higher efficiency power plants and implement air-cooling technologies in water-stressed regions (DOE, 2010). Table 4.1 presents a summary of the water-saving and recovery approaches being implemented outside the U.S.

4.4.2 Power plant flue gas water capture

During the last few decades, many studies have focused on recovering usable water from alternative sources such as water from the flue gas emitted by coal-fired power plants. The water vapor in flue gas comes from moisture content of the fuel, water vapor formed by the oxidation of hydrogen in the fuel and moisture content in the combustion air (Levy et al. 2008, 2011). For instance, a typical 400 MWe power plant burning coal and equipped with a FGD system could release about 150 m^3/h of water vapor through the flue stack (Levy et al., 2008) into the atmosphere. Compression systems used for oxy-combustion require also require the removal of nearly all flue gas moisture. The recovery of flue water could be a valuable source for power plants located in regions facing water shortages. The captured water, depending on its quality and acidity level, could be used in boilers as feed water, cooling water, or FGD makeup water, among other options. A brief review of various water vapor capture technologies is presented in the Appendix to this chapter.

Table 4.1 Water-saving approaches in coal power plants outside the U.S. (Adopted from DOE, 2010)

Country	Share of Electricity Generated by Coal (%)	Water Scarcity Drivers	Reducing Water Consumption Approaches (Direct and Indirect)
China	80	Third driest country in the world.	Indirect: replacement/retrofit of small, inefficient plants. Increase supercritical and ultra-supercritical units, and exploration of Integrated Gasification Combination Cycle (IGCC) technology. Direct: use of dry cooling and desalination systems.
Australia	70	Many areas subjected to severe drought, and groundwater use is restricted.	Indirect: supercritical steam cycles, coal drying, turbine upgrades. Direct: dry cooling and on site water-recycling.
South Africa	85	Coal resources and power plants located in dry regions.	Indirect: supercritical technologies. Direct: air-cooled condensers, advanced control systems, and desalination. Water infrastructure development.
India	70	Water issues are not a driver for power plant improvements.	Indirect: efficiency improvements (supercritical steam parameters). Replacement of old plants. IGCC research and development. Direct: reuse and recycle of wastewater.

4.4.3 Wet electrostatic precipitators

The use of wet precipitation for air pollution control has been widely studied; however, its application for simultaneous flue gas water recovery and pollution control requires further exploration. Khang et al. have proposed a flue gas water recovery system based on an air-cooled condensing wESP to be implemented in coal-fired power plants equipped with FGD units (Khang et al., 2008). A preliminary analysis of a proposed wESP, which is air-cooled through fins attached to its external walls, is also provided in the Appendix to this chapter.

4.5 Trends in water withdrawal and water consumption in coal-fired power plants in the U.S.

Information on coal-fired power plants was obtained through the U.S DOE/NETL website (DOE, 2007). It includes data from the EIA-767 database, which contains information on coal power plant generation, average water withdrawal and consumption, cooling water source, type of cooling water system, type of boiler and type of FGD system. The data was organized by the type of cooling systems used and electricity generation size bins. Furthermore, the water-related information was arranged by types of cooling systems because water withdrawal volumes vary according to the type of system. Additional coal-fired power plant data was obtained from the 2010 EIA database (EIA, 2012). The DOE and EIA data were then cross-checked to verify the validity of data on individual power plants

Power plants selected for analysis included those with boilers that utilized coal as the main fuel source. Boilers were further sorted based on the different types of coal used: bituminous and anthracite (BIT), lignite coal (LIG), sub-bituminous coal (SUB) and waste coal (WC). The boiler data was then linked to the generator data and cooling systems of each coal-fired power plant. Only those systems with an annual electricity generation higher than 100 MW were considered. Because the cooling system information is reported in the database as monthly averages, annual averages were calculated to facilitate its management and the identification of water-related trends. The systems were also sorted as either a once-through or recirculating type of cooling system. The once-through systems were classified according to the EIA database as systems using cooling ponds, freshwater and/or saline water while recirculating systems were divided into units with cooling ponds, natural draft cooling towers or mechanical draft cooling towers (forced and induced). After sorting the data and eliminating those units with incomplete cooling water information, the number of cooling systems analyzed totaled 416 units, of which 198 corresponded to once-through systems and 218 were recirculating cooling systems.

The annual electricity generation for the U.S. coal-fired power plants generating 100 MW or more for recirculating and once-through systems is shown in Figure 4.1.

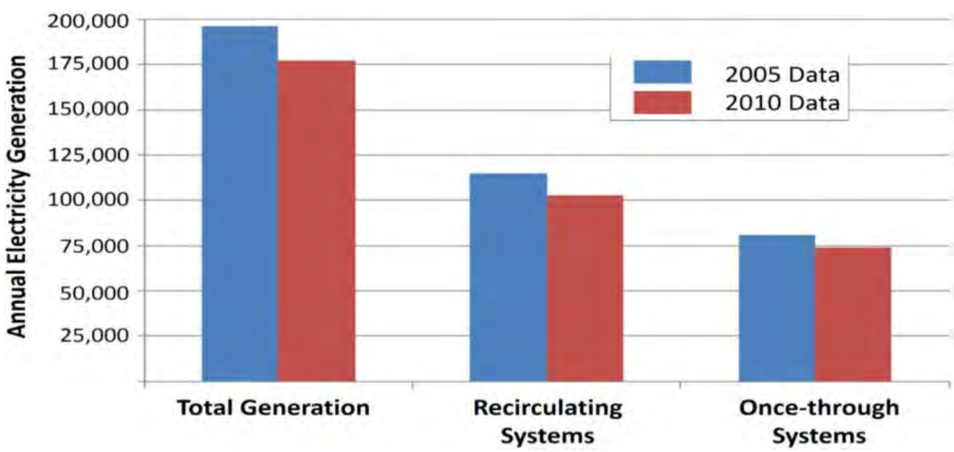

Figure 4.1 Annual electricity generation in coal plants (≥100 MW) in the U.S. Data from DOE (2007) and EIA (2012).

A 10 percent decrease in total annual electricity generation in coal-fired power plants occurred between 2005 and 2010 (Figure 4.1). In 2005, the annual electricity generation of the power plants included in the study was 196 GW, of which about 115 GW, or 58.6%, came from generators operating with recirculated cooling systems, and 80 GW (41.2%) used once-through cooling systems (Figure 4.1). In 2010, the total electricity generation was 177 GW, with 103 GW (58.2%) generated using recirculating cooling systems and 73 GW (41.6%) generated using once-through cooling systems. The increased use of recirculating cooling systems could be related to the implementation of more stringent regulations on water withdrawals and water discharges imposed by National Pollutant Discharge Elimination System (NPDES) permits[18]. According to the databases, only two coal power plants were operating with other types of cooling systems such as dry cooling systems that do not use water to cool steam. The coal plants are located in Wyoming and Illinois, and their combined electricity generation in 2010 was about 436 MW.

In the U.S., once-through cooling systems use either freshwater or saline water. Some power plants are equipped with cooling ponds through which the water is withdrawn from the source, utilized in the condenser and then sent to the ponds to lower the temperature of the water so that the thermal impacts on the source can be minimized during discharge. As seen in Figure 4.2, in 2010, 22 (16.7%) of the once-through cooling systems contained cooling ponds. The total number of freshwater once-through cooling systems (with or without installed cooling ponds) in 2010 was 176 units, comprising 92.1% of the total electricity generation from plants with installed once-through cooling systems (See Figure 4.2). The units using saline water once-through cooling systems represent only 7.9% of the total electricity generated in 2010. These units were mostly located on the East Coast (VA, MD, MA, CT, NJ, etc.) and at Florida's coal-fired power plants.

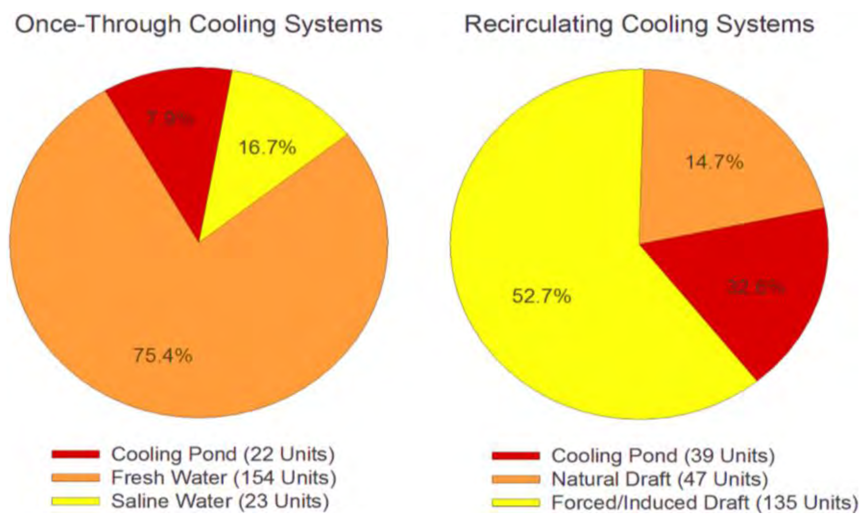

Figure 4.2 Percentage of electricity generated per cooling system type in 2010. Adopted from EIA (2012).

In addition to information regarding the use of cooling ponds, recirculating cooling systems in operation within coal power plants in the U.S. are also classified in the EIA databases according to their use of natural and mechanical draft (forced and induced) cooling towers. Most of the power plants operate mechanical draft cooling towers. In 2010, the amount of electricity generated by mechanical draft cooling towers was about 52.7% of the total electricity generated using recirculating cooling systems. Natural draft cooling accounted for about 47 units and approximately 39 units installed cooling ponds (Figure 4.2).

[18] More information on NPDES can be found at: http://cfpub.epa.gov/npdes/

4.6 Power Plant Carbon Models to Predict Water Withdrawal Rate

4.6.1 Description of models

An interactive Adobe Flash™ model has been developed to predict technology development trends of CO_2 capture in coal-fired power plants (Wang et al., 2014) and is schematically shown in Figure 4.3[19]. The model is designed to investigate and compare various methods of CO_2 sequestration. Inputs include power plant capacity (power generated, MW), coal parameters and CO_2 capture method. Outputs include necessary amounts of air for combustion (tons air/hour), CO_2 released per hour, ash produced per hour and cost of electricity per kWh. Water volumes (tons H_2O used per hour) are also calculated based on an empirical model.

Three different storage methods for CO_2 are shown schematically in Fig. 4.4, including enhanced oil recovery, depleted oil/gas reservoir and injection into saline aquifer, with costs of \$4.87, \$3.82 and \$2.93 per ton CO_2, respectively (Bock, 2003). The price point outputs will change as these unit costs vary with time. For all three storage methods, the Flash™ Model predicts that production of 500 MW of power utilizing conventional coal combustion without CO_2 capture would require 182 tons coal/hour, 1385.5 tons air/hour and 950 tons water/hour. Consequently, 27 tons ash/hour would be produced, while the amount of tons of CO_2 released/hour would depend on the storage method used for CO_2.

A Flash™ model was also developed for Integrated Gasification Combined Cycle (IGCC) power plants to predict carbon capture and water usage in the boiler and is schematically shown in Figure 4.5[20]. In a typical IGCC power plant, coal is burned with air and steam in a gasifier to form syngas ($CO+H_2$) at 2450°F and 615 psi. Bottom slag is also produced as a result and collected at the bottom of the gasifier. The syngas is sent to a particle capture device where fly ash is removed. The syngas, which is free of fine particles, then moves to the shift reactor where it is acted upon by steam and a catalyst to produce CO_2 and H_2. In the next step, sulfur is removed and collected for industrial purposes. In the CO_2 absorber, the CO_2 is separated by absorption. In the CO_2 desorber, the CO_2 is stripped off the absorbent, and the absorbent is regenerated for further use. Meanwhile, the H_2 that exits the CO_2 absorber is used to generate electricity in a gas turbine/steam turbine combined cycle. The input and output parameters are shown in Figure 4.5.

[19] An demonstration of this interactive model can be accessed at the following Internet URL: http://www.aerosols.wustl.edu/education/energy/CoalCO2/index.html

[20] An demonstration of this interactive model can be accessed at the following Internet URL: http://www.aerosols.wustl.edu/education/energy/IGCC/index.html

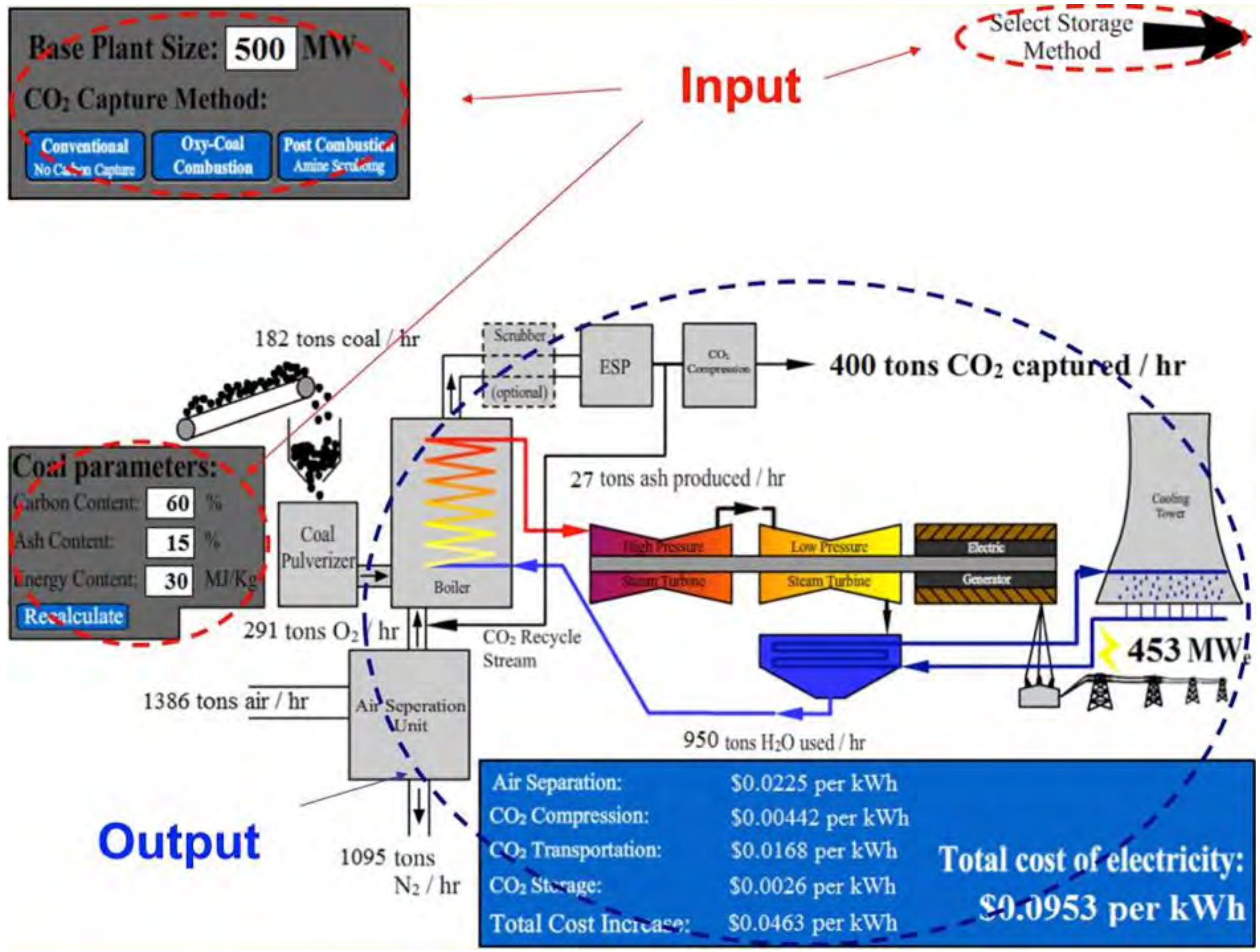

Figure 4.3 Schematic diagram of a coal fired power plant with/without CO_2 capture/sequestration. Adopted from Wang (2014).

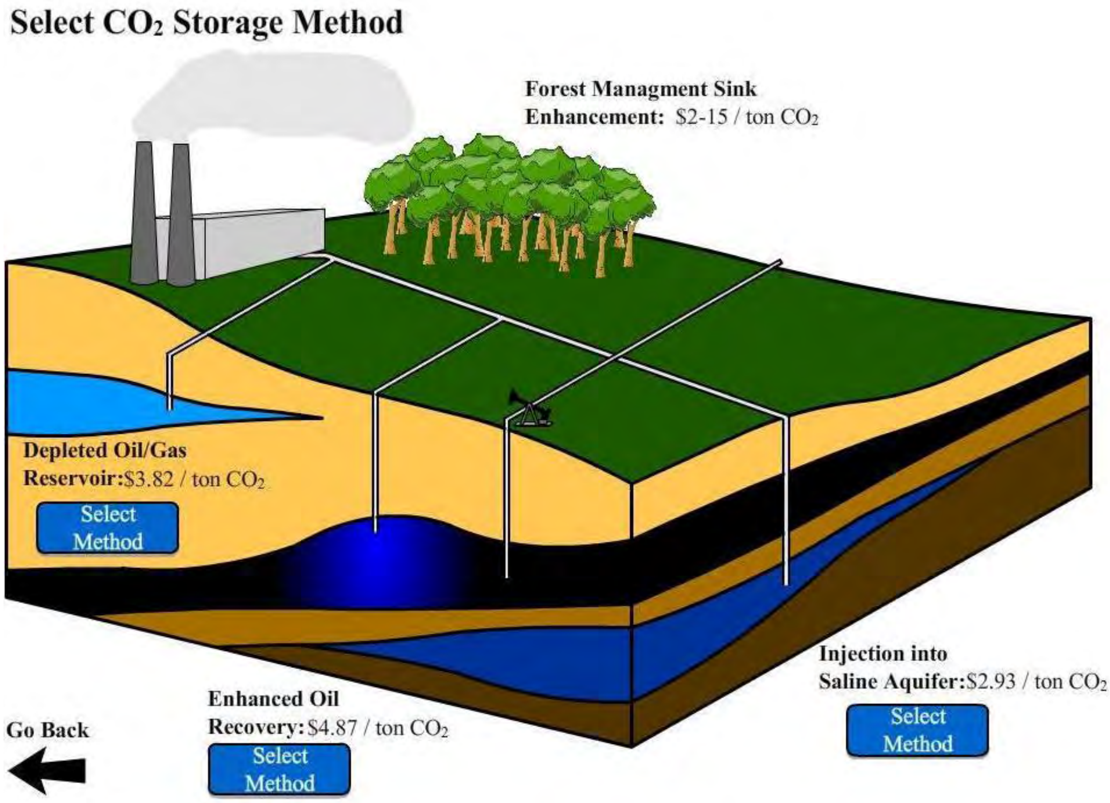

Figure 4.4 Flash™ model of different storage method. Adopted from Wang (2014).

Utilizing this model for a power plant producing 600 MW and CO_2 capture efficiency of 90%, using coal with 60% carbon content, 15% ash content, energy content of 30 KJ/Kg and 8% sulphur content, approximately 218 tons coal/hr, 349 tons O_2/hr and 1136 tons steam/hr is required. This produces 33 tons ash/hr, 17 tons sulphur/hr and 479 tons CO_2/hr, of which 90% is captured and stored. The total cost of electricity depends on which storage method is chosen. For example, if saline aquifer injection is chosen, the total cost of electricity will be $0.1081 per kWh.

4.6.2 Flash™ Module Calculation Comparison to EIA Data

The Flash™ model was validated by comparing the calculation results with EIA data (2010). The following equation, developed based on the classical energy balance principle, was used to calculate net power generation of coal-fired power plants:

$$\dot{M}_{coal-in}\left(\frac{kg}{hr}\right) = \frac{P\ (MW)}{Energy\ Content\ \left(\frac{MJ}{Kg}\right) \times 0.33} \times 3600\left(\frac{s}{hr}\right)$$

Here $\dot{M}_{coal-in}$ is the coal feeding rate (kg/hr), 0.33 is the typical thermal efficiency for this plant type, *P* and *Energy Content* are the plant size in MW and coal lower heating value (LHV) in MJ/Kg, respectively.

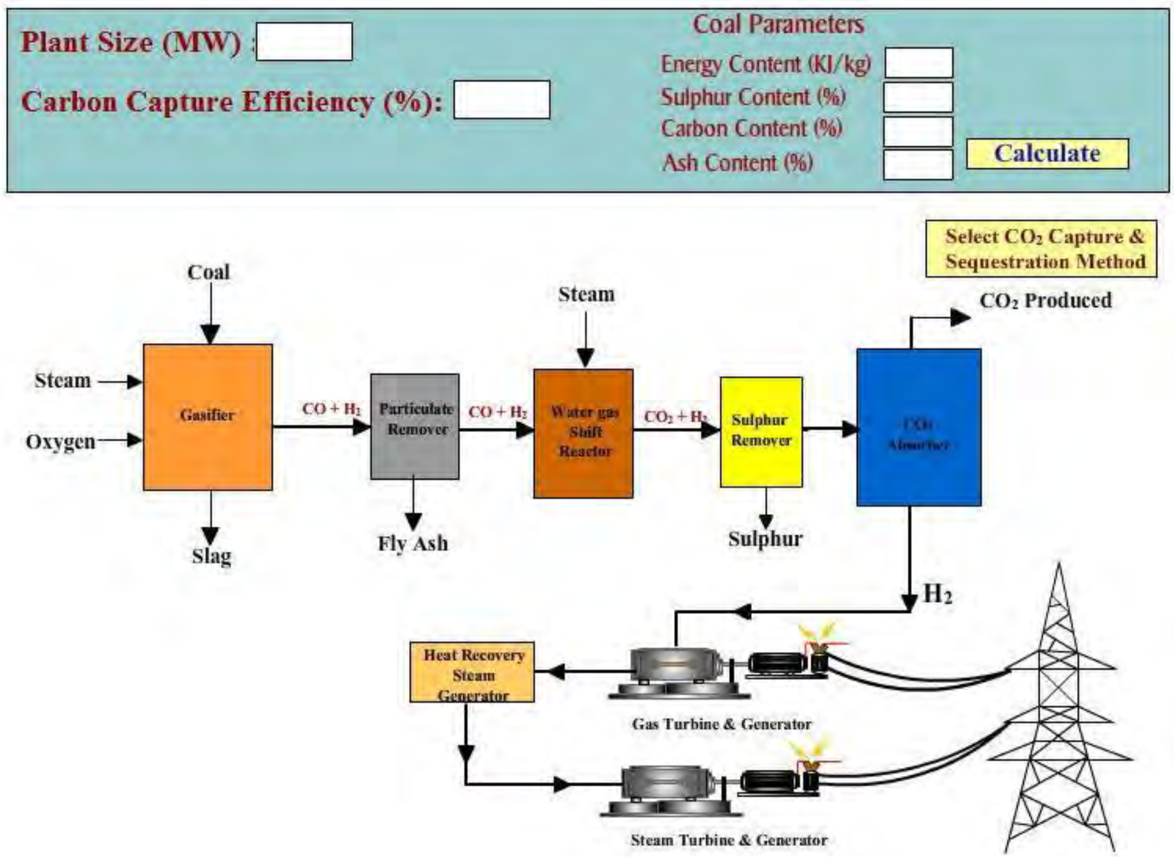

Figure 4.5 IGCC Flash™ Model. Adopted from Wang (2014).

Ten power plants across the country were selected for the validation, representing four major coal seams: Bituminous (low, medium and high volatile), Lignite (North Dakota and Texas) and Sub-Bituminous. The calculated annual fuel (coal) consumption rate (short tons/y) and the net power generation (MW) were compared with the corresponding EIA data (EIA, 2010). As shown in Table 4.2, the Flash™ model predictions agreed with the EIA data, with ≤10% error. The least error was achieved with power plants using Sub-Bituminous coal. Relatively large errors were found for the Texas power plants using Lignite coal, suggesting that modification of the Flash™ model is necessary depending on the coal type.

Water withdrawal rate values for specific power plants from the EIA database are reported in Table 4.2. The water use rate in a boiler based on the heating value and power rating of the facility (as calculated by the Flash™ model developed by Wang et al.) is also listed in Table 4.2 (Wang et al., 2014).

Table 4.2 Flash model validation for different types of coal seams*

Plant ID	Boiler #	Fuel Type	Lower Heating Value (KJ/Kg)	Total Fuel Consumption (Short tons/y, EIA data)	Total Fuel Consumption (Short tons/y, Calculated)	Error (%)	Annual Net Generation (MWh, EIA data))	Total MW (Converted from EIA data)	Total MW (Cal.)	Error (%)	Water Withdrawal Rate (tons/hr, converted from EIA data)	Boiler Water Use Rate (tons/hr, Calculated)
6019	1	Bituminous – High Volatile	26151	3980956	**3961873.15**	0.48	9700403	1107.35	**988.28**	10.75	716.55	2.096E+03
26	5	Bituminous – Low Volatile	33818	2306545	**2004924.90**	13.08	5638631	643.68	**740.48**	-15.04	182.47	1.218E+03
1378	3	Bituminous – Medium Volatile	30108	2599143	**2342358.04**	9.88	5864655	669.48	**742.88**	-10.96	NA	1.267E+03
2817	2	Lignite – North Dakota	14804	1831851	**2042946.99**	-11.52	2515030	287.10	**257.44**	10.33	1936.94	5.433E+02
6030	1	Lignite – North Dakota	14804	3835876	**3800084.62**	0.93	4678211	534.04	**539.07**	-0.94	NA	1.011E+03
6146	3	Lignite – Texas	14601	3685483	**5170338.90**	-40.29	6277820	716.65	**510.83**	28.72	NA	1.356E+03
6146	1	Lignite – Texas	14601	3655803	**4949412.36**	-35.39	6009568	686.02	**506.72**	26.14	28316.30	1.298E+03
6076	4	Sub Bituminous	19738	3668968	**3589536.55**	2.16	5891809	672.58	**687.46**	-2.21	132.52	1.273E+03
6257	4	Sub Bituminous	19738	3211671	**3321917.29**	-3.43	5302541	605.31	**601.78**	0.58	190.88	1.146E+03
6204	3	Sub Bituminous	19738	2757718	**2784781.99**	-0.98	4570897	521.79	**516.72**	0.97	87.16	9.875E+02

Note: *LHVs (energy content) are taken from DOE/NETL report: Detailed Coal Specifications, DOE-401/012111, January 2012.

4.7 Summary

This chapter provides a comprehensive overview of coal-fired electric power generation processes, and related water usage and wastewater generation. In the coal-based electric power plant, water withdrawal and water usage vary primarily depending on cooling technologies used to maintain the overall thermal system efficiency. There are two types of wet cooling systems, i.e., once-through cooling systems and recirculated cooling systems. In 2010, the total electricity generation was 177 GW, where 103 GW or 58.2 percent was generated at plants incorporating recirculating systems, and 73 GW or 41.6 percent was generated through the use of once-through cooling systems.

Based on the source of water withdrawal, once-through and recirculating cooling systems can be further identified as cooling ponds, freshwater, and saline water systems. For the once-through cooling systems, no significant differences were found among these three subcategories. Water withdrawal volumes range from 0.001 to 0.1m^3/MJ, based on data from 2010. The water withdrawal volume for once-through cooling systems is higher than that for the recirculating systems. The average water withdrawal rate for once-through cooling systems was 4.4E-02 ± 2.3E-02 m^3/MJ, and 4.2E-03 ± 1.0E-02 m^3/MJ for recirculating units in 2005. The water consumption, however, is expected to be higher in recirculating systems due to evaporation losses occurring in cooling towers. The water consumed in once-through cooling systems represented about one percent of the total water withdrawn, while for the recirculating systems, the water consumed was roughly 95 percent of the water withdrawn. The use of recirculating cooling systems is higher than that of once-through systems, which in the U.S. is related to the implementation of more stringent regulations on water withdrawals and water discharges imposed through the National Pollutant Discharge Elimination System (NPDES) permits.

One unique process in coal-fired power plants is the operation of Flue Gas Desulfurization (FGD) units. This air abatement process is commonly employed to reduce SO_2 emissions, a by-product of which is a significant contributor to the wastewater discharge emanating from coal-fired power plants. FGD designs include wet scrubbing, dry scrubbing, and dry sorbent injection. Wet scrubbing is being used in 85% of the FGD systems in the U.S., while dry scrubbing and dry sorbent injection represent only 12% and 3%, respectively, of total use in the U.S. For FGDs, wastewater generation, treatment, and disposal is the most pertinent issue impacting water use. Wet scrubbers require a constant purge flow to remove contaminants and maintain proper performance. This wastewater stream contains high concentrations of gypsum. Methods for treating FGD wastewater can be grouped into three categories: mechanical separation, chemical treatment or biological treatment.

An interactive module based on systems level modeling was developed using Adobe Flash™ to relate power plant emissions to power plant ratings and coal characteristics and water withdrawal for the different technologies. The model was validated by comparison with EIA power plant data reported by ten power plants. The program provides a comparison of three technologies, and also has baseline economic data on the resultant price of electricity. The module also reports water use rates in the boiler; however, actual water withdrawal rates, which are system specific, cannot be evaluated. Newer technologies such as supercritical oxy-coal with staged combustion that result in enhanced overall efficiencies were not evaluated in this work.

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4.9 Appendix

4.9.1 Flue gas desulfurization technology

4.9.1.1 The FGD process, types of systems, and wastewater generation

FGD is a process by which SO_2 gas, emitted during the burning of coal, is removed from the emissions of the plant. SO_2 is a major air pollutant, contributing to the acidification of rain, and is regulated by the EPA under the Clean Air Act (CAA). In FGD systems, flue gas comes into contact with (CaO) or limestone ($CaCO_3$) to form calcium sulfite ($CaSO_3$), which is usually converted into gypsum ($CaSO_4 \bullet 2H_2O$) by further processing, and accompanied by carbon dioxide (CO_2) release. The generated gypsum, along with the other flue gas components such as particulate matter, heavy metals, trace elements, and other harmful compounds, is captured and transferred into an absorbent slurry (liquid phase), while the CO_2 and other gases are released into the atmosphere.

Several FGD designs exist, the three most popular of which are wet scrubbing, dry scrubbing and dry sorbent injection. In the U.S., 85% of the FGD systems utilize wet scrubbing, while dry scrubbing and dry sorbent injection represent only 12% and 3% of the FGD systems, respectively (Higgins et al., 2009). Wet scrubbers are preferred in areas where the coal is high in sulfur content because they have a higher removal rate (>90%). Dry scrubbers, which only achieve ~80% removal, are used if the sulfur content is low (Heimbigner, 2007; Higgins et al., 2009). In a wet scrubber FGD system, particulate control devices such as an electrostatic precipitator are installed before the wet scrubber to remove most of the fly ash upstream of the scrubber. The flue gas enters the scrubber and is mixed with a spray of the treating solution, causing the SO_2 to solidify and stay in the solution. For dry scrubbers, this process is reversed. The dry or nearly dry treating chemicals are added into the flue gas, causing the SO_2 to form a solid dry particle. The flue gases then pass through the particulate control devices, removing the solid particles alongside the other particulates and ash. Wet scrubbers ultimately capture the SO_2 in an aqueous form while dry scrubbers capture it in a solid form.

Wet scrubbers require a constant purge flow of water to remove the contaminants and maintain proper performance. This wastewater stream contains high concentrations of gypsum, contaminants from the coal, lime or scrubbing solution and any pollutants introduced during processes that precede the scrubber. This wastewater has a variable pH range (4-9.6) and high concentrations of suspended and dissolved solids, heavy metals, trace elements, chlorides and other compounds (Higgins et al., 2009). Typically, the chloride concentration is one of the most important parameters in the wastewater because high chlorides can cause corrosion of the scrubber, water tanks, and gas pipes, and are the determining factor in how the scrubber is operated. The exact composition of the wastewater is difficult to predict, and is likely to change over time because of variations in coal and limestone sources. Plant design, plant operations, and scrubbing method will also affect the composition of the wastewater.

4.9.1.2 FGD wastewater composition and pollutants

TSS (total suspended solids) and TDS are major components of wastewater generated by coal-fired power plants. In a typical FGD system, solids usually consist of bottom or fly ash, other particulates, raw materials (e.g., limestone) and gypsum. Heavy metal and other trace element pollutants, including selenium, arsenic, mercury, antimony, beryllium and thallium, are present in potentially high quantities in power plant wastewater. Most of the pollutants originate from coal combustion, while aluminum compounds come primarily from the limestone used within the FGD. All of the listed pollutants are subject to ppb concentration standards due to their toxicity. Appendix Table 4.1 summarizes the national drinking water maximum contaminant level (MCL) standards compared with typical pollutant concentrations in the FGD wastewater along with potential health effects. The typical chloride limit for wastewater in many existing FGD systems is 12,000 mg/L to avoid metal corrosion. But, when corrosion-resistant metals are used, chloride concentrations as high as 35,000 mg/L are allowed. Chlorides also have disrupting effects on several wastewater treatment methods.

Appendix Table 4.1 Summary of pollutants included in FGD wastewater

Pollutant	Potential health effect(s)	National drinking water standards (MCLs) (μg/L)	Typical FGD wastewater (μg/L)
Aluminum	Nerve damage	50-200 (Secondary MCL)	87,478
Arsenic	Skin and circulatory system damage, risk of cancer	10	211
Boron	Stomach, liver and kidney damages	n/a	262,550
Copper	Gastrointestinal irritation, liver or kidney damage	1,300	2,153
Mercury	Kidney damage	2	56
Selenium	Hair and fingernail loss, numbness, circulatory problems	50	1,485
Chloride	Damage to respiratory system	250 mg/L (Secondary MCL)	14,592 mg/L
Total dissolved solids	N/A	500 mg/L (Secondary MCL)	31,025 mg/L

Note: Adopted from EPRI (2007a)

Nitrogen pollutants, including nitrites, nitrates and ammonia, are products of coal combustion processes. The fate of nitrogen compounds can vary depending on different upstream combustion temperatures. Most of the nitrates will be captured in a particulate-control device, but a significant portion will also be collected within the FGD. Nitrogen is a major component of other wastewater streams, particularly municipal wastewater, and each form has its own maximum allowable release standard. Depending on concentration, they can disrupt the treatment of other components as well.

Calcium and sulfates are other potential components of the wastewater. While not necessarily pollutants, they can be complicating factors during wastewater treatment. Calcium can lead to scale buildup, and sulfates can interfere with treatment processes (EPRI, 2007b).

4.9.1.3 Current FGD wastewater treatment systems

The combination of the described contaminants creates wastewater that requires careful handling. Generally, FGD wastewater is kept separated from other wastewater streams and treated independently. Methods for treating FGD wastewater can be grouped into three categories: mechanical separation, chemical treatment or biological treatment. Depending on the wastewater composition and plant needs, these processes can be combined or used in series to target different components of the wastewater with specialized processes.

- *Mechanical Separation*

Mechanical solid separation techniques such as a dedicated gravity settling basin, wetland, or dewatering system are the most widely used methods to separate suspended solids. The rich slurry containing suspended solids, after the FGD scrubber, will first pass through a mechanical separator to settle out some of the solids. The purged slurry then continues to flow into a hydrocyclone. This unit is designed as a retroflexed cone in order to settle out most of the gypsum. Meanwhile, the overflow from the hydrocyclone is introduced into downstream wastewater treatment units. After most of the gypsum and other solids are squeezed from the bottom of the hydrocyclone, a filtration process is used to dewater the gypsum, forming a solid gypsum cake.

<u>Evaporative Processes:</u> The evaporation method is a mechanical process currently used in many plants. It involves separating the water from the chemical residues in the wastewater via water evaporation, generating two products: distilled water and separated solids. The water can be captured and reused, or allowed to evaporate naturally in detention ponds. The separated solids are disposed of in a landfill or through further waste treatment. For example, ash ponds are used for the disposal of wet fly ash slurry. The ponds are constructed with low permeability clay layers and cut-off walls to prevent groundwater pollution. After evaporation, the solid fly ash is disposed. Advantages of the evaporation method include simplicity of the process, low concentrations of pollutants that meet discharge requirements, and zero discharge wastewater potential. This method is disadvantageous because of the large energy input required to heat the wastewater, separate it from the solids and then recapture it using condensers. Large detention ponds are required to use solar evaporation. Also, some of the contaminants can be volatile and may continue to be present in the distillate.

<u>Membrane Separation – HERO Process:</u> The HERO (high efficiency reverse osmosis) process is a membrane separation procedure that handles high silica content and treats cooling tower blowdown. The membrane is capable of operation at high pH (11.5), which is significant because silica is more soluble and the membrane fouling is reduced at high pH. Of particular interest is boron removal through HERO, because boron is not removed effectively by other technologies. Using the high pH capabilities of HERO, up to 99% of boron can be removed from a system (EPRI, 2007b). The disadvantages of the HERO process are the same as any membrane system: scaling and fouling remain major hurdles, and it requires pretreatment and possibly water softening.

- *Chemical Treatments*

Chemical treatment is used to precipitate calcium and magnesium ions as well as a portion of heavy metal and trace elemental pollutants via a hydroxide precipitation method (lime or sodium hydroxide). The post-treated water can be reused in the FGD plant. Additional chemical treatments such as iron co-precipitation and organic or inorganic sulfide precipitation can be employed to reduce the level of heavy metal pollutants.

Conventional chemical precipitation: lime precipitation for metal hydroxides: The most common chemical method for the removal of soluble metal ions from FGD wastewater is lime/hydroxide precipitation. In this process, metal ions are precipitated as metal hydroxides. Regulation of pH is a critical component of the precipitation. Since FGD wastewater can be acidic, the pH is often increased using alkaline chemicals like lime or sodium hydroxide. Because each metal has a unique solubility point, the rate at which they are removed from FGD wastewater varies from one plant to the next. Most heavy metal ions have lower solubility at higher pH. The lowest solubility for Cr is around 0.1 mg/L when pH is 7.4, Zn is 0.1 mg/L at pH 10 and Pb is 8 mg/L at pH 10. At pH 6, Cu has a solubility of 18 mg/L, but this number can go down to 0.05 mg/L if the pH is raised to 8. Ferric chloride and aluminum sulfate are usually added to accelerate heavy metal ion precipitation processes. Certain heavy metal ions such as copper, zinc and cadmium can form metallic complexes with ammonia. The complexes cause these heavy metals to stay soluble under high pH conditions. Adding soluble sulfide ions to the solution is the most widely used method to destroy the complexes, allowing the precipitation of the metallic ions and reducing the concentration of heavy metal ions to acceptable levels. Conventional lime precipitation can lower the concentration of heavy metal ions present in FGD wastewater. However, due to the lower threshold levels for the discharge of certain metal and elemental ions, additional enhanced chemical precipitations such as iron coprecipitation and inorganic metal sulfide precipitation may also be required.

Enhanced chemical precipitation: iron co-precipitation: In coal-fired power plants, the iron co-precipitation method is one the most promising technologies to lower heavy metals concentrations to ppb levels (EPRI, 2007b). It can effectively remove arsenic, selenium, cadmium, copper, silver, chromium and zinc; it is especially useful for arsenic and selenium removal. A ferric salt, typically ferric chloride or ferric sulfate, is added to the FGD wastewater stream, and reacts with water to form ferric hydroxide. Ferric hydroxide will quickly precipitate due to its low solubility. Ferric hydroxide has an amorphous structure that can absorb and bind the dissolved ions as well as suspended solids, and then eventually precipitate. Compared to hydroxide precipitation, iron co-precipitation removes a wider range of ions, resulting in overall lower final concentrations. However, since chloride and sulfate ions are introduced into the FGD wastewater, the iron co-precipitation treatment requires corrosive-resistant materials, and it will also increase the overall wastewater TDS concentration.

Enhanced chemical precipitation: Inorganic metal sulfide precipitation: Chemical precipitation using sulfide salts (sodium, ferrous or calcium sulfide) can achieve significantly lower metal concentrations in the treated water, often reducing residual metals 100- to 1000-fold, compared to hydroxide precipitation levels. Further advantages of sulfide precipitation are that, unlike hydroxides, metal sulfides are not amphoteric; hence, they do not resolubilize with changing pH, and residual metal sulfide sludge volumes are smaller. Sulfide precipitation effectively reduces most metals to very low levels, including copper and mercury. The disadvantage of using sulfide precipitation is the potential for forming hydrogen sulfide gas at low pH, and the effluent may have to be oxidized to reduce the dissolved sulfide residual after precipitation, depending on the type of sulfide salt used. While the sulfide process is suitable for the treatment of aluminum, copper and mercury, it is only marginally effective for arsenic and selenium (Merrill et al., 1987).

Enhanced chemical precipitation: Organosulfide precipitation with TMT 15: TMT 15 is a commercial organosulfide compound that is widely used in wastewater treatment in various industry areas, including combustion plants (like coal-powered plants), incineration plants, and the metal and mining industries. TMT 15 has two major applications: removing heavy metal ions (e.g., copper, lead, nickel, cadmium and silver) from wastewater, and reducing mercury emissions in wet FGD systems by using TMT 15 in the alkaline scrubber or incinerator scrubber. TMT 15 is a 15% aqueous solution of the trimercapto-s-triazine, tri-sodium salt developed to work similarly to sulfide precipitation, but without the drawbacks of using sulfides. The chemical is stable, can be stored safely, and produces a stable, non-toxic residual. It produces similar removal efficiencies to sulfide precipitation.

- *Biological treatment*

Biological treatment allows specific bacteria to attack and degrade pollutants via aerobic or anaerobic processes. A biological reactor in a coal-fired power plant can remove nitrogen, phosphorus, and some metals by precipitation. However, previous research shows that some compounds, including selenate, cannot be effectively treated. In general, biological treatment consists of nitrification and denitrification, but anaerobic processes can also be used. Ammonia and organic matter are converted to nitrate, biomass and CO_2 (gas) via nitrification, while nitrate and nitrite are converted to N_2 (gas) via denitrification. Nitrification is a strictly aerobic process while denitrification is an anoxic (no oxygen, but not yet anaerobic) process. Anaerobic processes can be used to produce methane, remove nitrogen and organic matter, and to capture metals, phosphorus, and other elements from the wastewater. The biomass absorbs the compounds through a variety of mechanisms, and they can then be captured by separating the biomass from the water. Any combination of these methods can be used, depending on the needs of the wastewater. Typically, biological treatments require some form of pre- or post-treatment to work effectively.

Compared with traditional chemical and physical wastewater treatment methods, biological methods are an effective means for the removal of elemental pollutants such as arsenic and selenium. Conventional biological treatments such as anaerobic biofilm reactor processes have shown an ability to remove heavy metals from FGD wastewater. A new process, called Advanced Biological Metals Removal Process (ABMet), developed by GE (Sonstegard and Pickett, 2009) has shown success in removing heavy metals, inorganic compounds and metalloids. A Constructed Wetlands Treatment System (CWTS, consisting of biological and physical adsorption processes) is another cost-effective and low-energy wastewater pollutant removal method.

ABMet Process: The ABMet process utilizes biofilms attached to activated carbon in an up-flow bioreactor to treat FGD wastewater. Within this reactor, a specialized mixture of microbes can reduce and precipitate most of the pollutants of concern from the solution or transform them into harmless formations. Metals, arsenic, selenium and nitrates can all be reduced to ppb levels using the process. For the microbes employed in this system, little attention is required. The reactor needs only a stream of nutrients, which can be fed automatically at a scheduled time. This can result in a highly effective, precisely controlled biological system.

Constructed Wetlands: Constructed wetlands simulate a natural wetland. They utilize the natural filtration and pollution removal capabilities of sediments and plants to remove nitrogen, phosphorus and trace elements from a wastewater as it permeates through the wetland. They are a low cost, low maintenance method for treating wastewater. However, they have been shown to provide little removal of some of the target species in FGD wastewater, particularly selenate (EPRI, 2007b). They also require a considerable footprint, depending on the wastewater flow rate, and will require a pretreatment step to reduce the solids content.

4.9.1.4 Alternative treatment systems

Single-use Sorption Media Processes: Two critical pollutants found in FGD wastewater are arsenic and selenium, which are required to be controlled at the ppb level. For this, metal-based adsorbents (granular ferric oxide or hydroxide and titanium oxide) have proved to be the most effective single-use sorption media. A case study examining the performances of these metal-based adsorbents was carried out by Anderson et al. (2003). The authors employed aluminum oxide, spinel and titanium dioxide as single-use sorption media to remove arsenic from groundwater. The results indicated that TiO_2 effectively converted As(III) to As(V), which is the easiest and most widely used way to remove arsenite. However, a major drawback of this method is that a complex nano-particle (TiO_2 in the form of nano-suspension) removal must be performed after the adsorption process. In the Anderson et al. study, a heterogeneous adsorbent, Al_2O_3/TiO_2, was employed instead of TiO_2. Thus, no separation process was required after adsorption. This heterogeneous adsorbent also contained a photocatalyst acting as an oxidizer, which can convert As(III) to As(V). The results of different experiments carried out by the authors indicate that the single-use sorption media along with photocatalytic adsorption could be an effective method for As removal without additional separation processes. Furthermore, mixed sorption metal media have demonstrated the capability to remove As more effectively than either pure TiO_2 or Al_2O_3.

Selective Ion Exchange: Selective ion exchange is widely employed in general wastewater treatment applications. However, only a few power plants have adopted this technology, likely because the ion exchange resins media can be easily plugged, especially by FGD wastewater with high concentrations of sulfate and dissolved solids. Similar to traditional ion exchange resins, selective resins can also be regenerated. Resins may contain different functional groups that can be used for selective ion exchange. Thus, specific ion exchange resins are being designed and tested for FGD wastewater treatments, such as removal of heavy metals and boron. Kabay conducted the first boron removal research at a power plant using a selective ion exchange method (Kabay and Yilmaz, 2004). Two resins called N-glucamine-type chelating resin Diaion CRB 02 and weak base resin WA 30 were packed into a stainless steel column. Wastewater was passed through the column, reducing the boron concentration from 20 mg/L to 0 mg/L (Kabay and Yilmaz, 2004). The total dissolved and undissolved SiO_2 concentration from power plant wastewater is high enough to easily plug the ion exchange column, and thus, a TDS pre-removal step is typically recommended before an ion exchange system.

Electro-coagulation and electrowinning: An alternative to the selective metal ion exchange method is the application of electro-coagulation and electrowinning treatments. The only difference between electro-coagulation and chemical precipitation is the presence of an electrode. In addition, electro-coagulation treatment may have a higher TSS removal efficiency. Chemical precipitation typically employs expensive aluminum, whereas the price of the iron electrode is a major benefit of electro-coagulation treatment. Less chemical reagents are required for electro-coagulation treatment compared to chemical precipitation, generating smaller amounts of sludge. Drawbacks of electro-coagulation treatment include high energy consumption and the necessity of electrode replacement. Although electro-coagulation has not yet been utilized using FGD wastewater, it has been successfully applied in industrial wastewater treatment.

Electrowinning technology could also be considered for FGD wastewater treatment. This technology focuses on the removal of metals, and operates on a principle similar to electro-coagulation. Essentially, the metals are plated out on the electrowinning electrodes. The electrodes will accumulate metal deposits that eventually need to be scraped off; alternatively, the electrode may also be replaced. This end point condition is noted by a drop of amperage across the plates. The scraped off metal or the removed electrodes can typically be disposed via a waste hauler for metal recovery or at a landfill as a non-hazardous material. The electrowinning technology is used primarily in metal plating and finishing processes. Although few applications for electrowinning can be found in wastewater treatment, it could recover nearly 100% of heavy metals from FGD wastewater.

4.9.1.5 Treatment technology selection

Overall, there is no single treatment method that can treat FGD wastewater at all power plants. A number of factors play a role in determining the most effective treatment, including location, coal type, plant design and discharge limits. Appendix Table 4.2 summarizes the advantages and disadvantages of wastewater treatment technologies that might be applicable to FGD wastewater. Appendix Tables 4.3 and 4.4 provide additional information from EPA reports on the treatment of CMD. While not identical, treatment of CMD requires many of the same considerations that apply to FGD wastewater treatment. The tables provide approximate cost, performance and advantage/disadvantage comparisons that can be used to guide the investigation of a treatment system for a given power plant and FGD wastewater.

Appendix Table 4.2 Summary of the reviewed wastewater treatments

	Evaporation	**Ion exchange**	**Sorption**	**ABMet**	**TMT 15**
Capital	High	Moderate	Moderate	High	N/A
O&M	Moderate	Low	Low	Low	Low
Health issues	Yes	No	No	Yes	Yes
Time required	Long term	Short term	Short term	Short term	Short term
Sustainability	Moderate	High	High	High	High
Disposition	On site and Off site	On site	On site	On site and Off site	On site and Off site
Public perception	No	Yes	Yes	N/A	N/A
Permanence	Yes	Yes	Yes	No	No

Note: Adopted from Cheng et al. (2011).

Appendix Table 4.3 Suggestions for selecting an appropriate CMD treatment technology

Selection Criteria	Coal Mine Drainage Treatment Technology			
	Chemical Precipitation	**Membrane Treatment**	**Ion Exchange**	**Biological Sulphate Removal**
Capital cost (per m^3/day capacity)	\$ 300 – 1,250	\$500 – 1,000	N/A	\$800 – 1,500
Chemical dosing	High	Limited	High	Variable
Energy efficiency	Moderate	High	Moderate	Low - Moderate
Operations & maintenance cost (\$ per m^3 treated)	\$0.2 – 1.5/m^3	\$0.5 – 1.0/m^3	N/A	\$0.7 – 1.5/m^3
Potential byproducts recovery	Gypsum	Potential, but not demonstrated	Gypsum	Sulfur
Proven technology on commercial scale	Proven, with large commercial plants	Proven, with several large commercial plants	Demonstrated on pilot scale, no large commercial plants	Proven, with a limited number of commercial plants
Performance	Robust process	Process good performance, but sensitive to pre-treatment	IX process performance and resin recovery subject to interference	Sensitive to toxics, fluctuating feed water quality and environmental conditions
Specialized application	General application to high metals, high SO_4 mine water	General application, but with appropriate pre-treatment	Demonstrated for TDS, with appropriate pre-treatment	Specialized application to high SO_4 mine waters
Waste sludge/brine production	Large waste sludge production	Sludge and brine production	Medium waste sludge production	Small waste sludge production
Water recovery	High water recovery > 95%	High water recovery > 90%	High water recovery > 95%	Very high water recovery > 98%

Note: Adopted from U.S. EPA (2013).

Appendix Table 4.4 Advantages and disadvantages of treatment technologies that can be used to remove TDS from CMD

Treatment Technology	Advantages	Disadvantages
Adsorption	Commonly available technology	Most TDS ions of interest are adsorbed to a limited extent, especially in the presence of other ions such as Fe, Mn, Zn, Pb, Co, etc.
Alkalinity Producing Systems	Can handle different flow rates, acid and metal loading rates, effective sulfate removal, uses limestone	Periodic exchange of substrate required, occasional clogging, requires steep slope and large land area
Anoxic Limestone Drains	Useful for coal acidic drainage, decreased overall rate of reaction, longer residence time provides better neutralization	High Al content armors limestone, tough to maintain anoxic conditions, does not handle volume and water quality fluctuations well, can only remove sulfate among the ions of interest, requires other metals such as Fe for effective sulfate removal
Bioremediation	Less expensive to install, natural process to treat contaminants, remediation not restricted to treatment zone	Some TDS components may not be amenable to biodegradation, site characterization and optimization needed for each site
Chemical Coagulation	Sludge settling, dewatering compacts waste	High cost, consumes lots of chemicals, may not remove all TDS components
Chemical Precipitation	Simple, inexpensive, removes most metals	Large amounts of sludge produced, sludge disposal problems, may not remove all TDS components
Electrochemical methods	Metal selective, no chemicals consumed, can recover pure metals	High capital, operating and maintenance costs, highly dependent on initial solution pH and current density
Electrodialysis	High recovery ratio, treats highly concentrated feeds, minimum pretreatment requirements, membranes not subject to scaling or fouling, field applicable	Frequent membrane leaks, bacteria, non-ionic chemicals and turbidity may affect treatment, requires a source of energy in the field
Ion Exchange	High regeneration efficiency, metal selective, portable, field applicable	High cost, requires a constant source of energy in the field
Lime Treatment	Most proven method for sulfate removal, can treat concentrated acidic CMD, most cost-effective for large flows or highly contaminated water	Requires frequent monitoring and sludge management

Appendix Table 4.4 (continued)

Limestone Ponds/Channels	Relatively inexpensive, low maintenance, minimal pretreatment requirements	Armoring of limestone reduces effectiveness, precipitated sludge requires management, may not remove all TDS components
Multi-Effect Distillation	Minimal pretreatment, high quality product, minimal operational requirements, high production capacity, low capital cost, concentration-independent energy requirements, treats highly concentrated feeds	Requires vapor cooling, low recovery ratio, water quality variations
Multi-Stage Flash Distillation	Can handle large capacities, minimum pretreatment requirements, high quality product water, can be combined with other technologies	Expensive to build and operate, low recovery ratio, requires lots of technical knowledge
Permeable Reactive Barriers	Can remove sulfates, extremely stable, can treat both surface water and groundwater	Uncertain life time, may need periodic replenishment of media, cost dependent on sulfate reduction rates, may not remove all TDS components
Reverse Osmosis	Can remove TDS components of interest, low energy requirements, high production ratio, can be used with most other technologies	High membrane and operating cost, affected by suspended particles, requires pretreatment and post treatment, relatively low flow rates, cannot operate under highly acidic, basic or high chlorine concentrations
Sulfate Reducing Bacteria	Availability of inexpensive organic substrates, minimal power requirements, can produce alkalinity to raise pH	Effluent sulfate concentrations may still exceed limits, occasional clogging, longevity dependent on carbon availability, requires large surface area
Ultrafiltration	Less solid waste produced, negligible chemical consumption, high efficiency	High initial, operating and maintenance costs, low flow rates, efficiency decreases in the presence of other metals
Wetlands	Easy to implement, low capital cost, low operational and maintenance costs	relatively low flows, large area and flat topography required, periodic sediment removal required, difficult to control metal migration, sensitive to low temperatures

Note: Adopted from U.S. EPA (2013).

4.9.2 *Flue gas water capture technologies*

Technologies to capture water from flue gas are described in the following subsections.

4.9.2.1 Liquid sorption

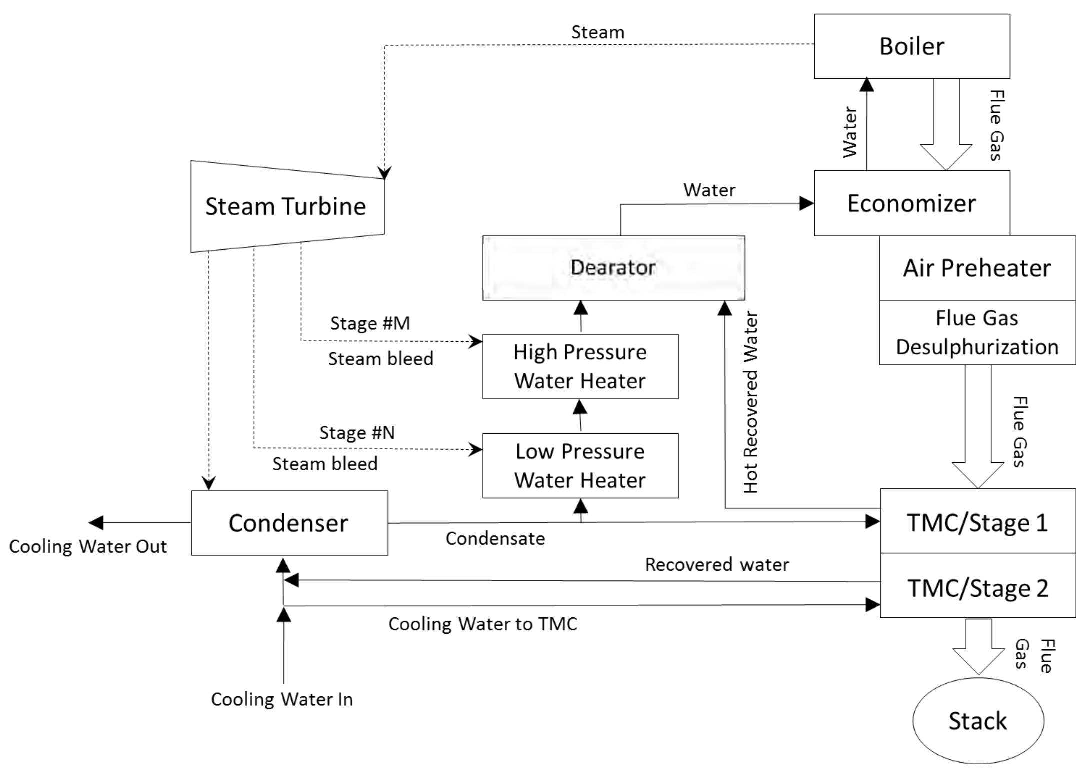
Liquid sorption is based on the preferential absorption of a gas mixture component by a liquid substance that is introduced into the gas stream. The driving force for the dehumidification system is the difference between the partial pressure of water in the gas stream and the partial pressure of water in the sorption substance or desiccant (Daal, 2012). Folkedahl et al. (2006) developed a liquid desiccant-based flue gas dehydration process to reduce the amount of water coal-fired power plants consume. The desiccant technology uses chemicals that extract water vapor through strong physicochemical affinity. No additional heating or cooling is required to capture the water because the process uses heat from absorption and vaporization. Furthermore, minimum pressure drops can be achieved through engineering design optimization (Folkedahl, 2006). More importantly, the process produces water of high purity, making it feasible to use the water in the steam cycle (Daal, 2012).

The dehumidification system involves the operation of absorption columns, where the desiccant flows downward and the flue gas flows upwards. After leaving the column and before being sent to the stack, the flue gas is passed through a demister to remove any entrained desiccant. The water-rich desiccant is heated and sent to a regenerator where water is separated from the desiccant solution using pressure differences (Daal, 2012). Different scale tests have been performed by Folkedahl et al. demonstrating that the technology exhibits up to a 70% water capture rate when using a calcium chloride solution (Folkedahl, 2006). Concerns regarding this technology include process safety due to the nature of the desiccant and corrosion caused by calcium chloride. The liquid sorption technology is already used in gas dehydration and in building dehumidification and cooling, but its use in coal-fired power plants is still considered to be in the demonstration phase. Economical and technical viability of the desiccant-based dehumidification system for coal power plants has been demonstrated for regions where the price of water is high (Daal, 2012).

4.9.2.2 Membranes

Gas separation membranes have been studied as a potential solution for flue gas water capture in power plants. In the U.S., the Gas Technology Institute (GTI) developed a water vapor extraction technology that separates water and latent heat from flue gas to later return them to the steam cycle. The technology, Transport Membrane Condenser (TMC), consists of water vapor passing through a nano-porous ceramic separation membrane and its further condensation by means of direct contact with a lower temperature water stream (Wang et al., 2012). The selectivity of the membrane recovers high quality water, inhibiting the transport of contaminants such as CO_2, O_2, NOx and SO_2. Industrial demonstration scale and commercial laundry applications have already proven the technology's effectiveness, and TMC is currently being commercialized for industrial boiler waste heat and water recovery; however, for coal power plant flue gas applications, GTI developed a two-stage design-tailored TMC technology intended to reach maximum heat and water recovery that can be used for boiler makeup water, FGD makeup water or other plant uses (Wang et al., 2012).

The two-stage TMC unit (Appendix Figure 4.1) uses two separate cooling water streams. On the flue gas side, the membrane condenser is located between the FGD unit and the stack. On the water side, the inlet water for the first stage TMC is obtained from condensed steam, and the water recovered and associated latent heat is sent to the de-aerator for later use as a boiler water makeup. The second stage TMC inlet water carries part of the condenser cooling water stream, and the outlet water is sent back to the cooling water stream with extra water recovered from the flue gas (Wang et al., 2012). The results of a pilot-scale test indicated that the membrane performance, evaluated in terms of water and heat recovery, increased when the moisture content in the flue gas increased, which matches the results obtained in laboratory-scale experiments. Furthermore, the impact of SO_2 concentration in the flue gas was evaluated. It was reported that typical values of SO_2 concentration in the flue gas had no significant effect on the water and heat recovery capacity of the TMC unit. Regarding the quality of the condensed water, the results showed that small amounts of SO_2 and CO_2 were dissolved in the water coming out of the membranes. Nonetheless, analyses demonstrated that the impact on water treatment needs would be minimal because the amounts of both compounds were very low as a result of the high selectivity of the membranes. Overall, the tests demonstrated a good heat and water recovery performance of the TMC technology for coal-fired power plant applications, especially for those that use high-moisture coals and/or FGD systems (Wang et al., 2012).



Appendix Figure 4.1 Schematic of a two-stage TMC for power plant flue gas heat and water recovery. Adopted from Wang et al. (2012).

Another membrane technology is being developed by KEMA (Daal, 2012), an energy services firm, through the CapWa project. This project aims to develop a technology capable of increasing location flexibility for the operation of power plants by recovering evaporated water. Results of the gas separation membrane tests in industrial plants in the Netherlands and Germany have revealed that at least 40% of the water contained in flue gases can be recovered. The quality of the water also is supposed to meet the boiler feed water quality requirements (Daal, 2012).

Limitations of the membrane technology include the energy demand of the water capture system due to the flue gas pressure drop, which is compensated for through the use of a vacuum force. Furthermore, the power requirement of air-cooled condensers has to be considered because cooling energy is needed to condense the captured water (Daal, 2012). The membrane technology for coal power plant applications has only been tested on a small scale; further studies need to be done before it can be applied on an industrial scale.

4.9.2.3 Condensing heat exchangers

The basic principle behind water vapor condensing by heat exchanger technology is reducing the temperature of the flue gas to the water dew point. Currently, a project by Levy et al. is under development (Levy et al., 2008; 2011), and the technology has proven to be effective on a pilot scale (Daal, 2012). According to Levy et al., the water vapor content in the flue gas highly depends on the coal rank. The flue gas water rate of a bituminous pulverized coal power plant generating approximately 600 MW can reach up to 200,000 lb/hr, while a power plant of the same size firing high moisture lignites could have a flue gas moisture flow of 600,000 lb/hr. On the other hand, the cooling makeup water requirements for the same power plant using cooling towers is 2.1 million lb/hr, which means that recovered water from flue gas could provide from 10% (bituminous coal) to 18% (Powder River Basin [PRB] coal), and up to 29% (high moisture lignites) of the makeup cooling water (Levy et al., 2008; 2011).

The authors have estimated a capture efficiency of up to 70% depending on different factors, such as flue gas water content (fuel type, wet FGD equipment), cooling water temperature, equipment design and flow rates of flue gas and cooling water (Levy et al., 2008; 2011). The maximum water capture-to-makeup water ratio for different types of coal is presented in Appendix Table 4.5 (Levy et al., 2011). It can be observed that the higher water capture-to-makeup water ratio is achieved when the condensing heat exchangers are located downstream of the wet FGD scrubber or when the coal moisture content is higher.

Other advantages of condensing heat exchangers and the cooling of the flue gas include:

- Reduced CO_2 Emissions: Latent and sensible heat recovered from the flue gas could be used to reduce the unit heat rate, thereby reducing CO_2 emissions.
- Reduced Acidity: Controlled acid condensation would provide environmental, operational and maintenance benefits due to the reduction of acid in the flue gas.
- Enhanced Mercury Removal: The lower temperature of the flue gas would allow for improved mercury removal.
- Reduced Cost of CO_2 Capture: Due to the reduced water and acid content in the flue gas, the cost of removing CO_2 would decrease (Levy et al., 2008; 2011).

One of the biggest disadvantages of this technology is the potential for corrosion and fouling problems caused by reducing the flue gas temperature (Levy et al., 2008; 2011). The common operating temperature for the flue gas is 300°F, which prevents acid condensation and provides a buoyancy force to assist in the transport of flue gas up the stack. The dew point of the sulfuric acid depends on SO_3 concentrations in the flue gas, and it is known that for concentrations up to 35 ppm, sulfuric acid begins condensing at temperatures between 250°F and 310°F. The dew point of the water vapor, considering a flue gas moisture content of 6 to 17.5 volume percent, is in the range of 100°F to 135°F. The dew points of other acids present in the flue gas, such as hydrochloric and nitric acids, have a similar temperature range as that of water vapor (Levy et al., 2011). To achieve water recovery in the condensing heat exchangers, the flue gas is cooled down to the water vapor dew point, inevitably causing co-condensation of acids and water. As a result, water treatment and acid trap installation should be considered to avoid corrosion in the heat exchanger tubes and damages to the cooling system.

Appendix Table 4.5 Estimated fractions of cooling tower makeup water achievable, assuming 100% water vapor capture

Case	Inlet Flue Gas Moisture Fraction (% Volume)	Maximum H_2O (Capture/Makeup H_2O)
Bituminous (Unscrubbed)	6 - 8	0.10 - 0.13
Bituminous (Wet FGD)	16 - 17	0.30 - 0.33
PRB (Unscrubbed)	10.5 - 12	0.19 - 0.22
High Moisture Lignite (Unscrubbed)	15.5 - 16.5	0.29 - 0.31
Lignite (Wet FGD)	17.5	0.33 - 0.34

Note: Adopted from Levy et al. (2011).

As previously mentioned, one of the benefits of lowering the flue gas temperature is the increased potential for mercury removal. Mercury measurements by Levy et al. showed that vapor phase mercury decreased by 60% between the inlet and exit of the heat exchanger system when the flue gas was extracted downstream of an ESP, and the reduction was between 30% and 80% when the flue gas was extracted downstream of a wet FGD (Levy et al., 2011). It was also noted that the percent captured increased as the flue gas exit temperature decreased. Analyses of the technology suggest that the installation of condensing heat exchangers downstream of the wet FGD systems would be cost-effective, where the benefits include water recovery from flue gas for use within the power plant and increase in net unit power output (Levy et al., 2011).

4.9.3 Design optimization of air-cooled condensing wet ESP for flue gas water recovery

One of the objectives of the present study was to review different approaches for freshwater consumption reduction within coal-fired power plants. Khang et al. (2008) proposed the use of an air-cooled wet electrostatic precipitator (wESP) for the simultaneous removal of water and pollutants from the flue gas of coal power plants equipped with flue gas desulfurization (FGD) systems (Khang et al., 2008). Water recovery systems using wESPs as flue gas water condensers are still in their early stage of research and development, and many design parameters are yet to be optimized. Therefore, during this study, a heat-transfer optimization of the system's design was performed. The first design presented by the authors is briefly described below. Even though the authors found high water capture efficiencies, further estimations regarding heat transfer optimization were needed to advance the development of the water saving system being proposed. The estimations carried out attempted to obtain an optimized ESP design, as well as a fin configuration, where not only the water recovery would be maximized, but the power requirements would be reduced as much as possible.

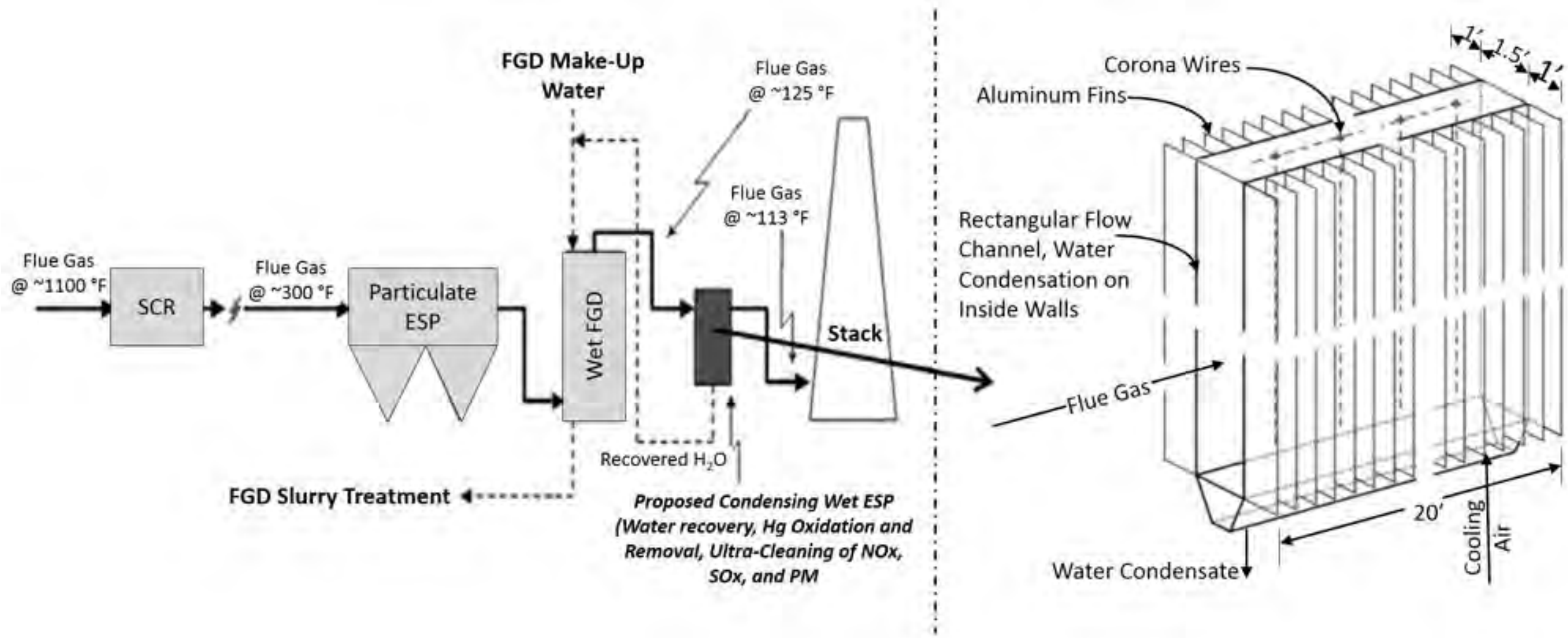
4.9.3.1 Air-cooled condensing wet ESP initial proposal

As mentioned previously, a system has been proposed that is intended for the simultaneous recovery of water and removal of residual pollutants from flue gas through the use of an air-cooled wESP. The design of the system consists of a cluster of five condensing wESPs installed after each FGD unit. Water vapor present in the flue gas is condensed out in the inner walls of the ESP, where the wall temperature is maintained lower than that of the flue gas by external heat transfer fins. The amount of condensation depends on the external heat transfer through the fins, and the collected water is recycled back to the wet FGD unit; thus, no additional water treatment facilities are required. Preliminary schematics of the proposed system are presented in Appendix Figures 4.2 and 4.3.

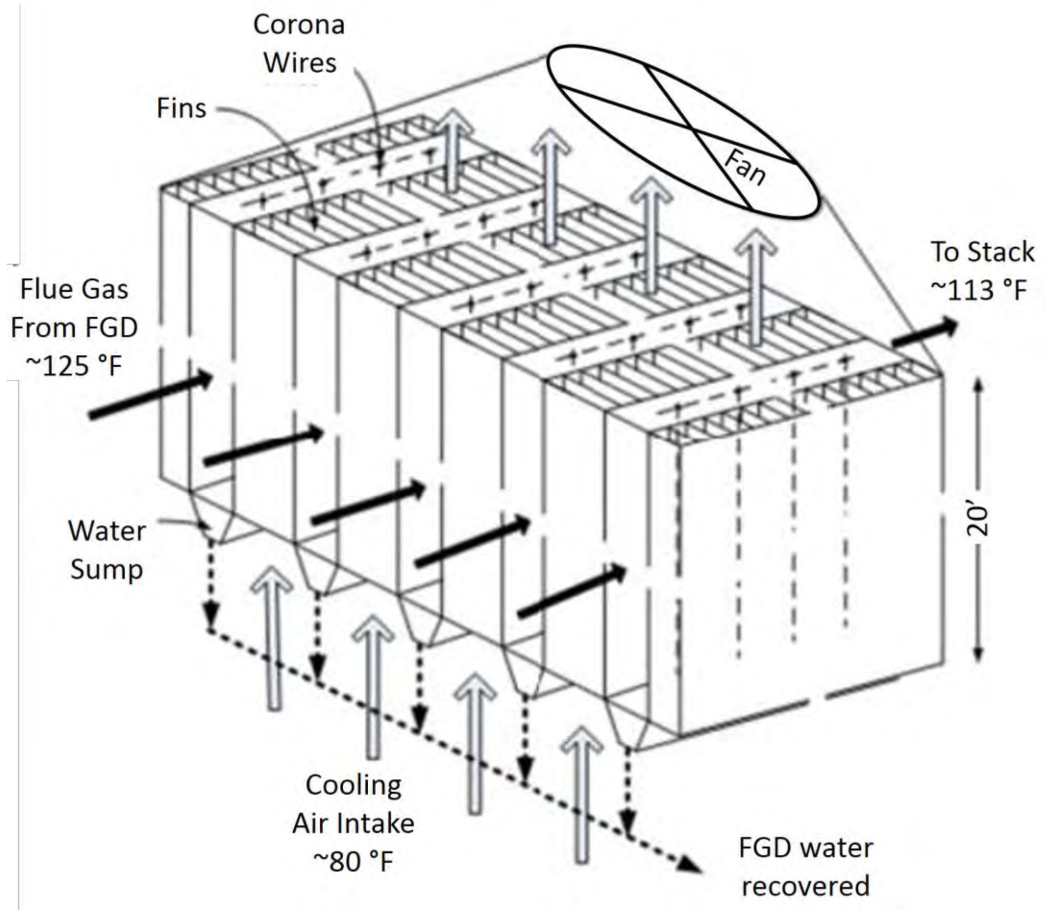
Previous heat transfer estimations of the proposed system have shown the following potential advantages:

- Significant water recovery. Considering a typical 500 MW power plant at 80°F air temperature, it has been estimated that it is possible to recover FGD makeup water in the amount of 9,670 gallons/hr (43% of the total) or 14,700 gallons/hr of water (65% of the total) using a 0.5MW or 2.5MW air fan, respectively. The amount of water recovered will highly depend on surrounding temperature and fan power, as will be shown later. Additionally, cost savings from the recovered water is sufficient to cover the cost of extra electric power requirement for an air fan.
- Water condensation and corona wind lead to a high heat transfer coefficient in the unit.
- Low pressure drop through the unit due to the wide and empty channels of the ESP.
- Traditional mist eliminators in a wet FGD unit are no longer needed since fine particles are effectively removed in the proposed wESP unit, which saves approximately 0.5 inch-H_2O pressure drop.
- There is no need for extra water to clean the collection walls since the condensed water can serve this purpose.
- Additional removal of residual SO_x, NO_2 and oxidized mercury due to the high mass transfer coefficient achieved by corona wind and electron attachment mechanism.

Heat transfer coefficients and water recovery efficiencies were estimated for a typical 500 MW coal-fired power plant based on an initial fin configuration for the wESP (See Appendix Figure 4.4). The preliminary results, as observed in Appendix Figure 4.5, show the dependency of water recovery on the fan power (cooling air velocity).



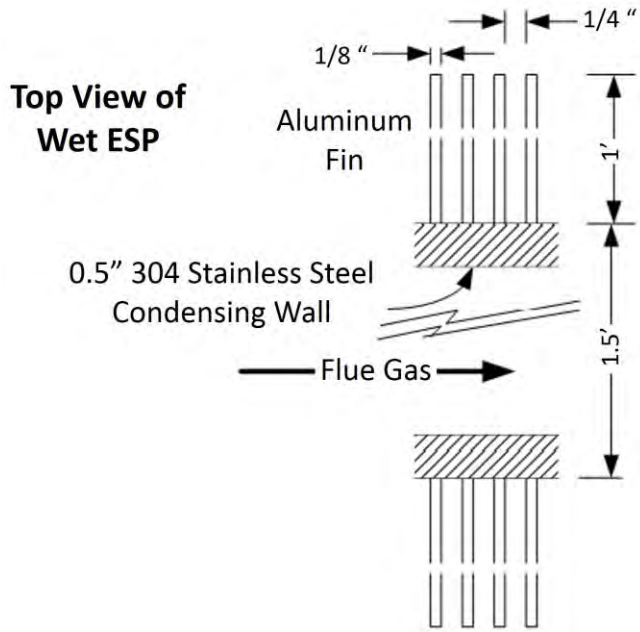
Appendix Figure 4.2 Condensing wet ESP system within the power plant and wet ESP unit with external air-cooling.



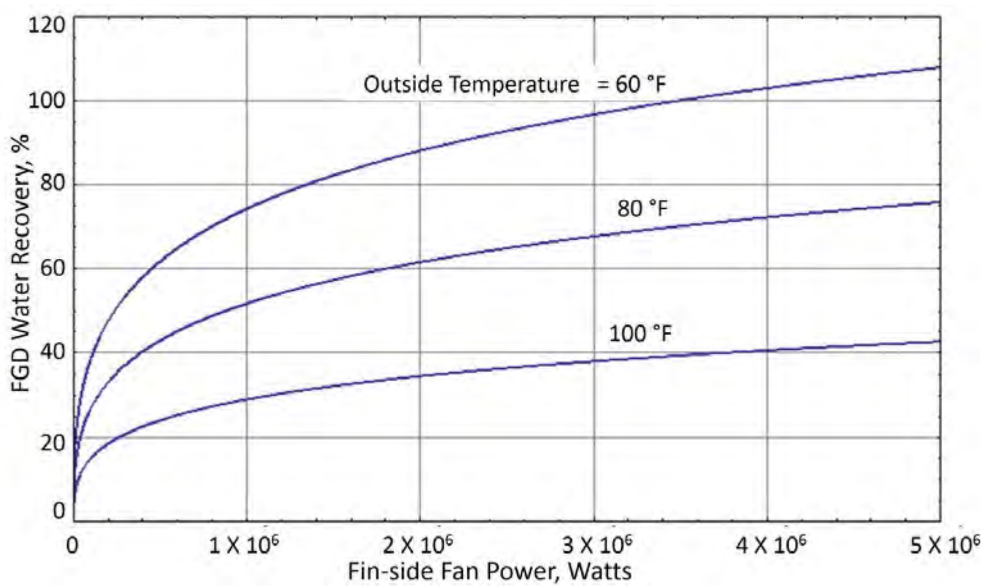
Appendix Figure 4.3 System's design- a cluster of five ESP per FGD Unit. Adopted from Khang et al. (2008).

Also, from Appendix Figure 4.6, it is possible to observe the influence of cooling air temperature on water recovery efficiency. In both figures, the FGD water recovery percentage refers to the percentage of FGD makeup water that can be captured and fed to the system.

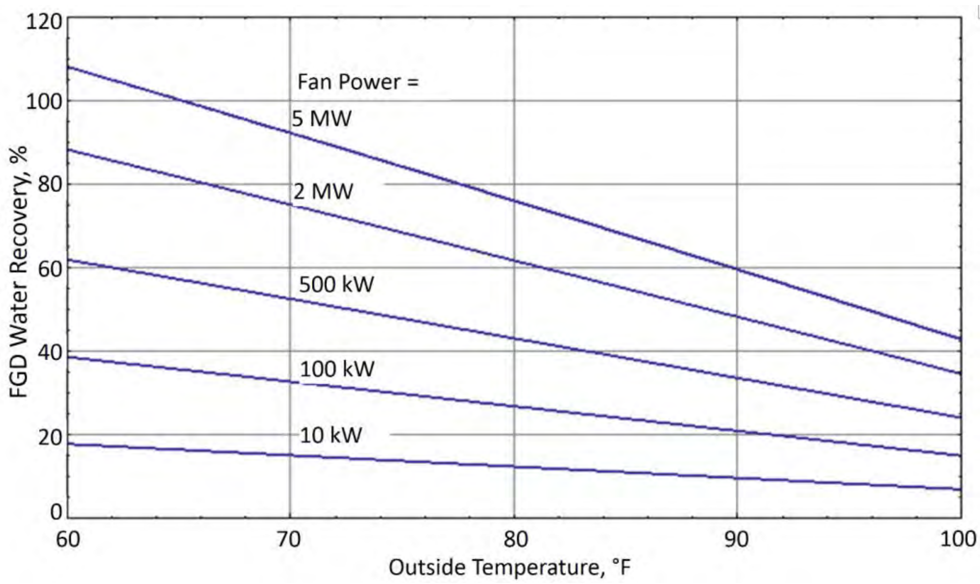
Furthermore, it has been estimated that the proposed configuration requires ten charging wires of 18 ft in length per unit, which results in a consumption of 2.1 kW for each wESP unit. Therefore, the total wESP power consumption is estimated to be 52.5 kW for a 500 MW plant with 25 wESP units (this can vary depending on particulate loading in the flue gas). Nonetheless, the power consumption by the ESP is still much lower than the power required for external air cooling, indicating that the major power consumption for the proposed system comes from the air fan for outside cooling. For this reason, future work regarding this part of the project will focus on heat transfer optimization, which involves defining a fin configuration to achieve the maximum fin heat transfer (highest water condensation rate), while minimizing fin-side fan power.



Appendix Figure 4.4 Condensing wet ESP initial fin configuration.



Appendix Figure 4.5 FGD water recovery vs. fin-side fan power.



Appendix Figure 4.6 Effects of outside air temperature on water recovery.

4.9.3.2 Heat transfer optimization methodology

The original proposed system's configuration and fuel information was used as a base for the optimization. All the information and design specifications were taken from the Project Narrative prepared by Khang et al. (2008). The design parameters originally presented by the authors are indicated in Appendix Table 4.6.

Appendix Table 4.6 ESP channels and fin characteristics.

Fins	
Thickness, in	1/8
Width, in	12
Length, ft	20
Spacing between fins, in	1/4
Number of fins on each side of the channels	640
Thermal conductivity (aluminum), Btu/ft.h.°F	136
Channels	
Length, ft	20
Width, ft	1.5
Wall thickness, in	1/2
Thermal conductivity (stainless steel), Btu/ft.h.°F	25.9

Note: Data source from Khang et al. (2008).

The heat-transfer simulation for the wESP channels were carried out with the use of a calculus model developed in Mathematica v.8 for Students (Wolfram, Boston, MA). The simulation code was validated by comparison with preliminary results from Khang *et al*. (2008).

The most important equations used for the heat transfer estimations are introduced in Section 1.9.3.3. The calculation process is described later on.

4.9.3.3 Fundamental equations

The equations used to define the required variables within the estimation process are presented in the international system of units (SI). The calculation model included the conversion equations for the variables calculated; so, the results were presented in the English units according to the design specifications (See Appendix Table 4.6).

Water Vapor Pressure Correlation (Perry et al., 1998)

$$Pw(T) = \frac{Exp(A+B\cdot T-\frac{C}{T})}{T^{8.2}} \tag{4.9-1}$$

where,

$Pw(T)$ = Water vapor pressure, Pa

T = Flue gas temperature, K

A = 77.3450

B = 0.0057

C = 7235.0

Water vapor density (Perry et al., 1998)

$$\rho(T) = \frac{0.0022\cdot Pw(T)}{T} \tag{4.9-2}$$

where,

$\rho(T)$ = Water vapor density, Kg/m^3

Heat of vaporization (Perry et al., 1998)

$$Hv(T) = 0.1292 \cdot C_1 \cdot \left(\frac{1-T}{Tr}\right)^{C_2+\, C_3\cdot T/\,Tr\cdot C_4\cdot T/Tr\cdot T/Tr} \tag{4.9-3}$$

where,

$Hv(T)$ = Heat of vaporization of water, KJ/Kg

C_1 = 5.2053 x 10^7

C_2 = 0.3199

C_3 = -0.2120

C_4 = 0.25795

Tr = 647.13

Number of fins

$$noFins = \frac{2 \cdot ESPLength}{Thickness+Spacing} \tag{4.9-4}$$

where,

noFins = Number of fins per ESP channel

Thickness = Thickness of the fins, m

Spacing = Space between fins, m

Heat transfer coefficient calculations (Perry et al., 1998; Bayless et al., 2004)

$$h_0 = \frac{Nu \cdot k}{D_{eq}} \tag{4.9-5}$$

where,

h_0 = Heat transfer coefficient, Watts/ m^2- K

Nu = Nusselt number

k = Thermal conductivity of air, Watts/ m-K

D_{eq} = Equivalent diameter, m

$$Nu = 0.0265 \cdot Re^{0.8} \cdot Pr^{0.3} \tag{4.9-6}$$

where,

Re = Reynolds number

Pr = Prandtl number

$$Re = \frac{D_{eq} \cdot v \cdot \rho}{\mu} \tag{4.9-7}$$

where,

v = Velocity of air on fin side, m/s

ρ = Density of air, Kg/m^3

μ = Dynamic viscosity of air, Kg/m-s

$$D_{eq} = \frac{Channel\ Area}{Wetted\ Perimeter} \tag{4.9-8}$$

where,

Channel Area = Area of the channel created by the fins and the ESP channels wall (it is two times the fin width times the spacing between fins), m^2

Wetted Perimeter = Perimeter of the fins channel where the air passes through (it is twice the fin spacing plus four times their width, because it is calculated on both walls of the ESP channel).

Air temperature on the fin side

The air temperature on the fin side was calculated considering the temperature gradient along the fin length. This was done by using the efficiency of the fin (EIA, 2014)

$$mL = \sqrt{\frac{2 \cdot h_0}{kfin \cdot t}} \cdot w \tag{4.9-9}$$

$$eff = \frac{ArcTan\ (mL)}{mL} \tag{4.9-10}$$

where,

eff = Efficiency of the fins

mL = Fin efficiency parameter

kfin = Thermal conductivity of the fin (aluminum), Watts/m-K

w =Fin width, m

The temperature of the air along the fin length is then found by performing an energy balance.

$$\frac{Tair - Tw}{To - Tw} = Exp\left(\frac{4 \cdot eff \cdot h_o \cdot w \cdot L}{Q_{air} \cdot C_{p_{air}}}\right) \tag{4.9-11}$$

where,

Tair = Temperature of the air on the fins side, K

Tw = Temperature of the wall of the wESP channel (assumed to be the same of the flue gas), K

To = Initial temperature of air, K

Qair = Air flow rate, kg/s

L =Fin length, m

Cp =Heat capacity of air, kJ/kg-K

Heat transfer from the fin

$$q = Q_{air} \cdot C_{p_{air}} (T_{air} - T_o) \quad (4.9\text{-}12)$$

where,

q = rate of heat transfer from the fin, kW

Water condensation rate

$$W_f = {}^{q}/_{H_v(T)} \quad (4.9\text{-}13)$$

where,

Wf = Water condensation rate, kg/s

Fan power equations (Perry et al., 1998)

The fan power was calculated by multiplying the pressure drop by the air flow rate.

$$\Delta P = 4 \cdot f \cdot \rho \left(\frac{L}{D_{eq}}\right) \frac{v^2}{2} \quad (4.9\text{-}14)$$

where,

ΔP = Pressure drop, Pa

f = Fanning friction factor, which is calculated by using the Blasius equation for turbulent flow

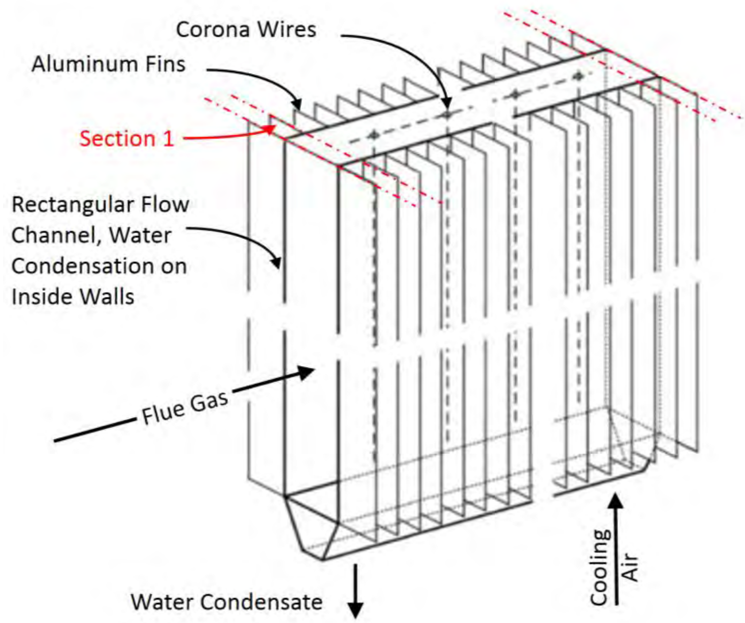
$$f = {}^{0.079}/_{Re^{0.25}} \quad (4.9\text{-}15)$$

Then, the total fan power per each wESP channel is:

$$f = \Delta P \cdot Channel\ Area \cdot Total\ no. Channels \cdot v \quad (4.9\text{-}16)$$

4.9.3.4 Heat transfer calculation process

The amount of water from the flue gas that could be condensed within one wESP channel under given circumstances was estimated through an iterative process. One of the most important aspects to consider was that while the flue gas is passing along the x-axis of the wESP channel, its temperature is continuously decreasing due to the water condensation; thus, changing the ESP wall temperature. Khang et al. (2008) demonstrated that the ESP wall temperature is the same as the bulk flue gas temperature because of the significantly large value of the condensing heat transfer coefficient on the inside of the walls. For calculation simplicity, the flue gas temperature change or the wall temperature change was calculated for each section of the ESP channel, creating the iterative process. A section, in this study, corresponds to the wESP channel region delimited by two fins on each wall of the channel, as shown in Appendix Figure 4.7.



Appendix Figure 4.7 Sections in the wESP channel.

The fin-side heat transfer coefficient, h_o, was calculated using Equation 5 for a specific set of conditions (air velocity on the fin side and fin configuration). For the first section of the wESP, the fin efficiency from Equation 10 is used to determine the change in the cooling air temperature (Equation 11), which represents the heat transferred from the fin-side to the wESP wall (Equation 12). The water condensed in the section is calculated using Equation 13. The water contained in the flue gas was determined based on the power plant efficiency and the type of coal burned. For this study, a typical power plant with an electricity generation capacity of 500 MW was assumed. The properties of the coal and flue gas used for the calculations are presented in Appendix Table 4.7.

The water removed from the flue gas in the section is then subtracted from the total water contained in the flue gas. The condensation of the water results in a change in the water vapor partial pressure in the flue gas; thus, the flue gas temperature changes according to Equation 1. This new temperature is used to consecutively calculate the water removed in each section until the nth section. The summation of the water removed in the sections from the 1st to the nth gives the total water removed in the wESP channel.

Another important factor to consider was the power usage or parasitic power in the system. The heat transfer on the fin-side of the wESP is enhanced by forced convection, which is achieved through the use of fans installed to force the cooling air through the fin channels. The velocity of the cooling air on the fin side is then directly proportional to the fan power exerted or vice versa. For the system proposed, different air velocities were assumed and the fan power was calculated using the Blasius correlation for turbulent flow, as previously shown in Equations 14 and 15. For each air velocity assumed, the water removal was calculated.

Appendix Table 4.7 Properties of coal and flue gas assumed

Coal Characteristics	
Coal heating value, Btu/lb	11,150
weight % carbon	61.2
weight % hydrogen	4.3
weight % oxygen	7.4
weight % sulfur	3.9
weight % nitrogen	1.2
weight % ash	12.0
weight % moisture	10.0
Flue Gas	
Excess combustion air, %	20
Amount of dry exhaust gas, scf /106 Btu of fuel	11,554
CO_2 in dry exhaust gas, volume %	15
O_2 in dry exhaust gas, volume %	3.4
Molecular weight of dry exhaust gas	30.7

Note: Source from Khang et al. (2008)

4.9.3.5 Heat transfer optimization process

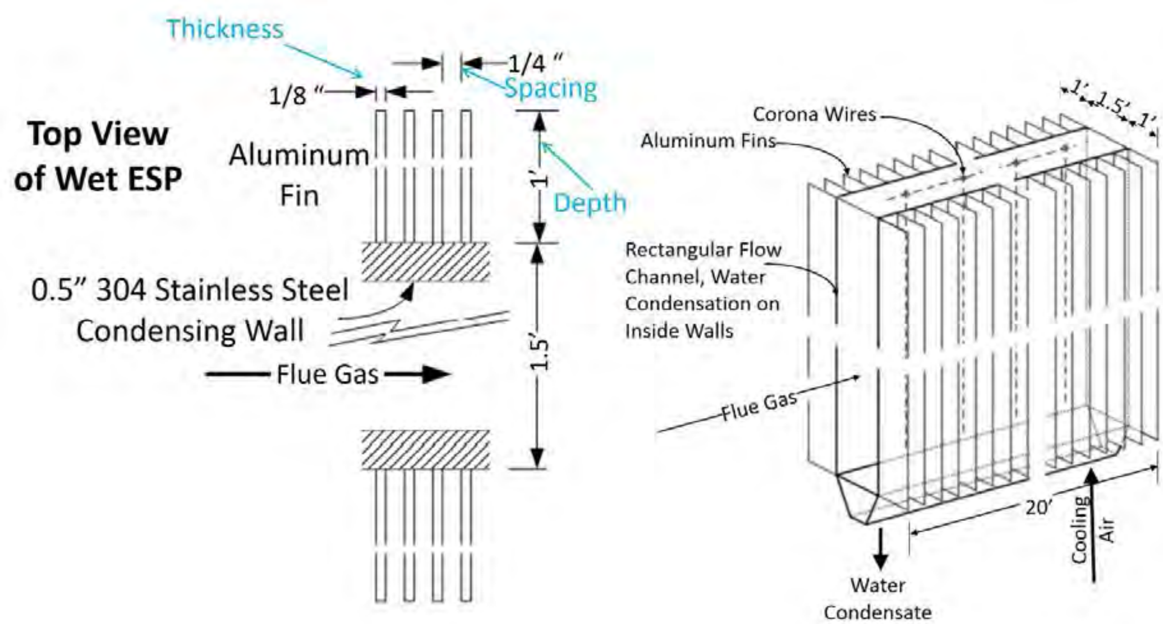
The heat transfer optimization of the air-cooled condensing wESP was carried out in two parts. The first approach was to simulate different fin configurations based on the original proposal written by Khang et al. (2008), and then identify how the various configurations influence the heat transfer, and thus, the water removal. As mentioned before, the goal of the heat transfer optimization was to achieve a higher water removal while minimizing the fan power requirements. In this first part, two parameter variations were analyzed.

Varying fin spacing and thickness

To determine how changing the fin configuration in the wESP based on fin spacing and thickness (number of fins per ESP channel) would influence the heat transfer, nine cases besides the original, or initial case proposed, were evaluated (see Appendix Table 4.8). The original configuration is presented in Appendix Figure 4.8. The only parameters changed during this part of the optimization were the fin thickness and spacing.

Appendix Table 4.8 Cases of fin configuration evaluated varying spacing and thickness

Case	No. Fins	Spacing+t (ft)	Spacing (ft)	t (ft)
Original	1280	0.031	0.021	0.010
1	1600	0.025	0.015	0.010
2	2000	0.020	0.010	0.010
3	2500	0.016	0.006	0.010
4	1280	0.031	0.026	0.005
5	1280	0.031	0.016	0.015
6	1600	0.025	0.020	0.005
7	2000	0.020	0.015	0.005
8	1000	0.040	0.030	0.010
9	1000	0.040	0.035	0.005



Appendix Figure 4.8 Condensing wESP original fin configuration.

Varying fin depth

All the previous cases were evaluated again by varying the fin depth, which was originally one foot, as shown in Appendix Figure 4.8. The different depths evaluated are presented in Appendix Table 4.9 with their respective case label.

Appendix Table 4.9 Cases of fin depth evaluated

Fin Depth (ft)	Case Label
1.0	---
1.5	w1
2.0	w2
3.0	w3

The second part of the heat transfer optimization process involved the definition of ESP design parameters that directly influence the ESP dimensions, and thus, influences the heat transfer phenomena occurring. These design parameters are briefly described below (Holman, 1997).

4.9.3.6 Specific collection area (SCA)

It is the ratio of the collection surface area to the gas flow rate into the ESP channel. The SCA represents the ratio A/Q in the Deutsch-Anderson equation; therefore, it is an important parameter in the determination of the ESP collection efficiency.

$$SCA = \frac{Total\ Collection\ Surface\ (ft^2)}{Gas\ Flow\ Rate\ (1000\ \frac{ft^3}{min})} \tag{4.9-17}$$

Increasing the SCA in the design generally leads to an increase in the collection efficiency of the precipitator. A general range of SCA is between 200 and 800 ft^2 per 1000 acfm depending on the design conditions and desired efficiency.

Aspect ratio (AR)

The AR is the ratio of the length of the ESP to its height. This parameter is important when considering dust re-entrainment at the moment of trapping. Effective plate lengths are at least 35 to 40 ft, which helps reduce the amount of collected dust that comes out of the ESP.

$$AR = \frac{Effective\ Length\ (ft)}{Effective\ Height\ (ft)} \tag{4.9-18}$$

For high efficiency ESPs, the AR is usually between 1.0 and 1.5, and sometimes it can reach values close to 2.0.

Gas flow distribution

The gas velocity inside the ESP influences the particle collection. The gas velocity into the ESP is generally reduced to 2 – 8 ft/sec for adequate collection. For aspect ratios of 1.5, the optimum gas velocity is typically between 5 and 6 ft/sec.

Considering the ESP design parameters introduced above, new cases for the wESP dimensions were proposed and analyzed, including the original case presented in the previous section. The new dimensions proposed for analysis are presented in Appendix Table 4.10.

Appendix Table 4.10 Wet ESP dimensions variation cases

Case/Dimension	Original	A	B	C	D
ESP Length (ft)	20	50	60	50	40
ESP Height (ft)	20	40	40	40	20
ESP Channel Width (ft)	1.5	1.3	1.3	1.3	1.5
No. ESP	25	60	60	40	40

All the cases presented in Appendix Table 4.10 were simulated in order to determine the best water recovery potential. For each case, different fin configurations were evaluated considering the results obtained in the first part of the optimization process. The flue gas water removal percentages and fan power requirements were estimated for each case in order to determine the optimum water recovery system design.

4.9.3.7 Heat transfer optimization results

The first attempt for the optimization process consisted of changing the fin configuration of the ESP to determine the factors influencing the water removal efficiency and the power requirements. The second part focused on the design parameters of the ESP and the further required changes in the fin configuration that would allow the optimization of the heat transfer within the system. The results of both parts are presented below.

4.9.3.8 Fin configuration

The original fin configuration was varied by changing the spacing and thickness of the fins and by changing the depth of the fins. Nine different cases, the details of which are presented in the Methodology section, were simulated in order to evaluate how the spacing between the fins and their thickness influence the water removal. The results are presented in Appendix Table 4.11.

Appendix Table 4.11 System parameters and water recovery obtained from changing fin spacing and thickness

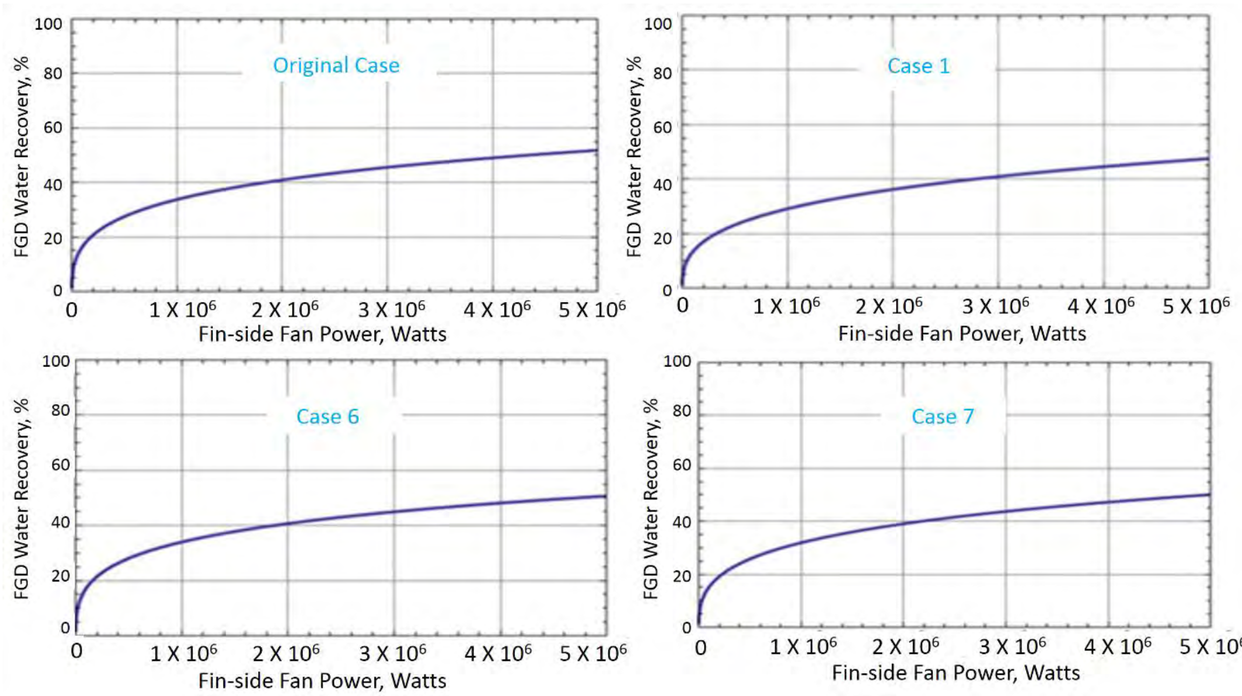
Case	Reynolds Number	ho (BTU/ °F-ft²-hr)	Fin Efficiency	FGD Make Up (%)	Total Water (gallon/hr) per ESP
Original	18328.1	22.8	0.173	54.8	494.3
1	12977.6	24.4	0.167	55.1	496.7
2	8673.3	26.5	0.160	50.3	454.0
3	5214.3	29.3	0.152	39.8	358.9
4	22584.7	21.8	0.125	50.4	454.6
5	14050.4	24.0	0.206	49.7	448.4
6	17260.6	23.1	0.121	56.3	507.4
7	12977.6	24.5	0.118	60.5	545.4
8	25763.4	21.3	0.179	50.6	456.8
9	29983.5	20.7	0.128	43.1	389.1

As indicated in Appendix Table 4.11, four configurations, whose results are highlighted in blue, exhibited the highest water recoveries from the flue gas. In these cases (cases 1, 6 and 7), compared to the original case, increasing the number of fins, which means decreasing the fin spacing, and in some cases their thickness, results in a higher percentage of water removal (fin spacing and thickness were given in Appendix Table 4.8).

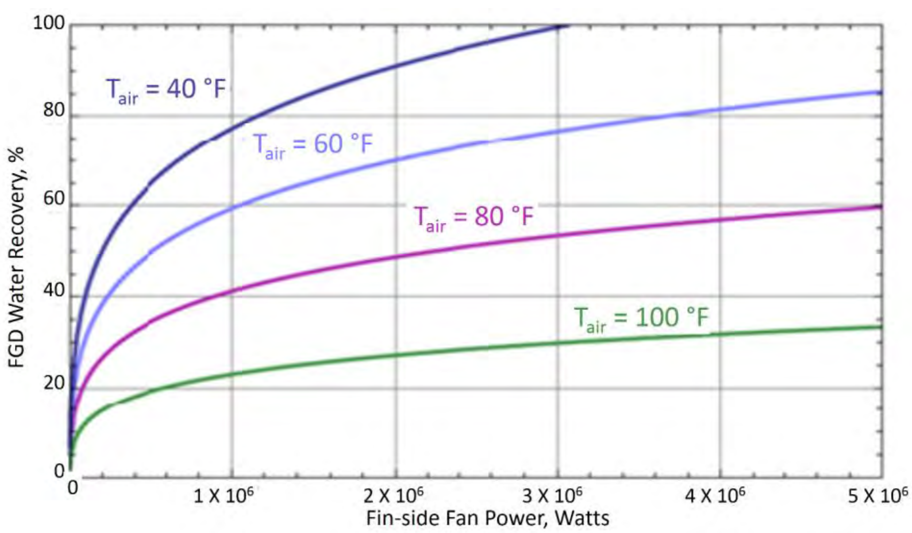
When it comes to the fin-side fan power requirements, a slightly lower fan-power requirement is obtained when evaluating cases 6 and 7 in comparison to case 1, as presented in Appendix Figure 4.9. However, no improvements regarding power usage are obtained when compared to the original case. For instance, with the original configuration (See Appendix Figure 4.3), if a water removal of 40 percent of the FGD makeup water is desired, the fin-side fan power required would be around 2 MW (for cases 6 and 7), whereas for case 1, the fan power needed is around 2.8 MW. From Appendix Table 4.11, water recovery improvements are observed when comparing cases 6 and 7 to the original case; thus, as a preliminary result of this first part of the optimization process, cases 6 and 7 can be considered to offer the best fin configurations.

The previous estimations were conducted maintaining the original fin depth (1.0 ft.). The second part of the optimization process involved changing the depth of the fins from 1.0 ft. to 1.5, 2.0 and 3.0 ft. The analysis of the results indicated that increasing the depth of the fin enhances the heat transfer in the system; thus, the amount of water removed from the flue gas is higher. Also, by analyzing the fan-power results for those cases where the water recovery percentage was higher, it was observed that the fin-side fan power requirements decrease when increasing the depth of the fins, which is a desirable condition as part of the optimization process.

From the results obtained in the first part of the optimization process, case 7w-2 was chosen for further analysis due to the higher water capture efficiency and lower power requirements exhibited. Appendix Figure 4.10 shows the effect of fin-side fan power on water recovery for different cooling air or outside air temperatures.

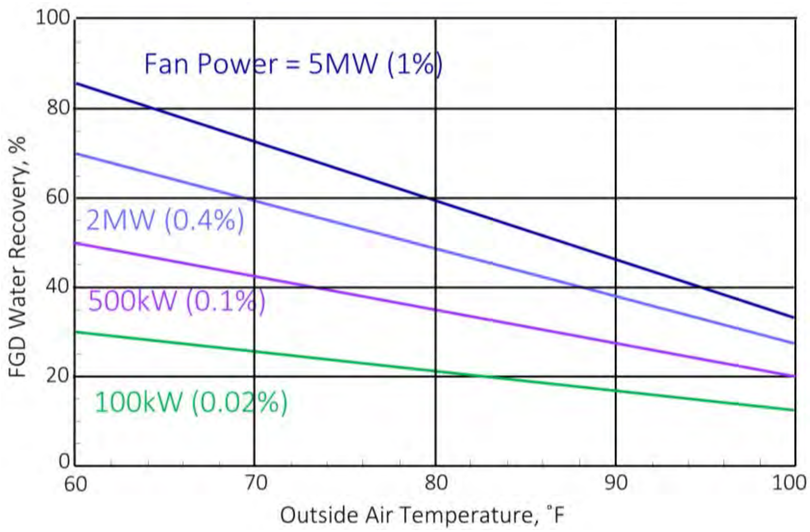


Appendix Figure 4.9 FGD water recovery % vs. fin-side fan power for the highlighted cases.



Appendix Figure 4.10 Effect of fin-side fan power on FGD water recovery % for case 7w-2.

As expected, increasing the fin-side fan power results in a higher amount of water recovered. Also, the lower the cooling air temperature, the better the heat transfer that was achieved, and thus more water is condensed, as observed in Appendix Figure 4.11. Here, the effect of the outside air temperature on water recovery for different fan-power curves is presented. The number in parenthesis for each fan-power curve represents the percentage on the power requirement based on total power generation of a 500 MW power plant.



Appendix Figure 4.11 Effect of outside air temperature on FGD water recovery % for case 7w-2.

4.9.3.9 wESP Design Parameters

The second part of the heat transfer optimization process involved the definition of ESP design parameters directly related to the ESP dimensions, which also influences the heat transfer phenomena. As indicated in the Methodology section, new cases for the ESP dimensions were proposed and analyzed, including the original case presented in the previous section. The dimensions analyzed along with the ESP parameters are presented in Appendix Table 4.12.

The purpose of this part of the process was to define ESP dimensions that would result in design parameters that best approach the typical ESP design values, or fall between the typical ranges. This would guarantee high particulate collection efficiencies and a better operation. The design parameters considered for the purpose of this analysis were the aspect ratio (AR), the specific collection area (SCA) and the gas velocity. These parameters were determined for five different cases including the original case. As observed in Appendix Table 4.12, one of the problems with the original case is the low SCA and the high gas velocity achieved, which could result in significantly low ESP performance. In light of this, the length, height and number of ESPs were varied. The results indicate that when increasing the ESP's length and height, but maintaining the AR within the typical range, a SCA within the typical range can be achieved. Furthermore, the number of ESPs required to lower the gas velocity, and thus improve the collection efficiency, has to be between 40 and 60 for the specific dimensions chosen.

Appendix Table 4.12 Proposed cases for ESP dimensions and design parameters calculated

Case/Parameter	Original	A	B	C	D	Typical Design Values
Flue gas rate (acfm)	9.80E+05					-
ESP Length (ft)	20	50	60	50	40	-
ESP Height (ft)	20	40	40	40	20	-
ESP Channel Width (ft)	1.5	1.3	1.3	1.3	1.5	0.5 – 1.3
No. ESP	25	60	60	40	40	-
AR	1	1.25	1.5	1.25	2	1 - 2
SCA (ft^2/1000 acfm)	20	245	294	163	65	200 - 800
Gas Velocity (ft/s)	21.8	5.2	5.2	7.9	13.6	5 - 6 If AR=1.5

It is important to note that the aspect ratio and the specific collection area play an important role in the ESP collection efficiency and particle re-entrainment; however, the load of particles in the flue gas entering the water recovery system is expected to be very low because the flue gas had already gone through a particulate control system. Therefore, typical ESP design values do not need to be strictly followed, but close approximations are desired. The gas velocity, on the other hand, represents an important parameter for water vapor condensation, where long residence times inside the ESP channels are required in order to reach a higher heat transfer.

Three cases A, B and C were simulated in order to find the water recovery efficiencies for each case. The only difference between cases A and C is the number of ESP channels, 60 for Case A and 40 for Case C. Case D was not considered for further analysis since the design parameters calculated fall far off the typical ranges. For the new cases, ten different fin configurations were proposed based on the results obtained in in the previous section. Simulation results indicated that cases A-9 and C-9 exhibit the highest water recovery while minimizing fin-side fan power. Also, the cost of the systems in Cases A and C are expected to be lower when compared to Case B since the ESPs length is smaller.

The results from simulating Case A for each fin configuration are given in Appendix Table 4.13, which shows the recovered FGD makeup water percentage, the total water per ESP and the total fan power for a specific gas velocity for all the specific cases. It can be observed that the percentage of FGD makeup water recovered from the system is high for all the configurations proposed; thus, this is not a limiting variable. On the other hand, the fin-side fan power requirements vary from one configuration to the other. For instance, the total fan power needed decreases when increasing the number of fins attached to the ESP walls. The total fan power is directly related to the number of sections and number of ESP channels in the system. As a reminder, a section corresponds to the channel on both exterior sides of the ESP where the cooling air flows between two fins (see Appendix Figure 4.4). Therefore, decreasing the number of fins decreases the number of sections, and thus, the total fan power required is reduced. The same would be expected if the number of ESP channels is reduced, as in Case C. In summary, the configurations of cases A6, A8, A9 and A10 exhibited the best results when considering water recovery maximization and fan power minimization.

Appendix Table 4.13 Results for Case A (length = 50 feet, height = 40 feet, no. ESPs = 60)

Case	FGD Make Up (%)	Total Water per ESP (gallon/hr)	Total fan Power (Watts)
A1	266	911.64	7.76E+07
A2	217	744.31	9.02E+07
A3	267	915.87	7.36E+07
A4	264	905.34	1.05E+08
A5	268	917.86	9.81E+07
A6	265	909.87	4.17E+07
A7	262	897.47	4.48E+07
A8	261	896.15	4.06E+07
A9	244	837.49	1.75E+07
A10	258	884.78	1.80E+07

The simulations were also carried out for Case B and the results are presented in Appendix Table 4.14. The behavior of the different configurations for Case B was similar to that of the Case A configurations. It is observed that, even though the length of the ESPs is longer than in Case A, no significantly higher water capture efficiencies are achieved when simulating Case B. In addition, the fin-side fan power is not greatly reduced. Thus, Case B was not considered for further analysis since its implementation supposes higher costs and footprint than cases A and C, with no significant improvements in performance.

In view of the results presented in Appendix Tables 4.13 and 4.14, two cases were chosen for further analysis in this section. The two cases correspond to those where the highest water recovery is reached, while the least fin-side fan power consumption is required (Case A9 and Case C9).

Case A9

The dimensions of the ESP channel for the proposed case are:

Length = 50 ft.

Height = 40 ft.

Width = 1.3 ft.

Number of ESP Channels = 60

Appendix Table 4.14 Results for Case B (length = 60 feet, height = 40 feet, no. ESPs = 60)

Case	FGD Make Up (%)	Total Water per ESP (gallon/hr)	Total fan Power (Watts)
B1	268	920.51	7.28E+07
B2	259	889.69	8.17E+07
B3	268	919.86	7.01E+07
B4	268	919.90	9.81E+07
B5	269	921.40	9.31E+07
B6	267	916.37	3.97E+07
B7	267	916.68	4.20E+07
B8	263	903.50	3.89E+07
B9	247	847.96	1.68E+07
B10	261	896.47	1.72E+07

The fin configuration with a better performance corresponded to 1000 fins for both exterior walls of the ESP channel. The fin dimensions are:

Fin length = 50 ft.

Fin height = 40 ft.

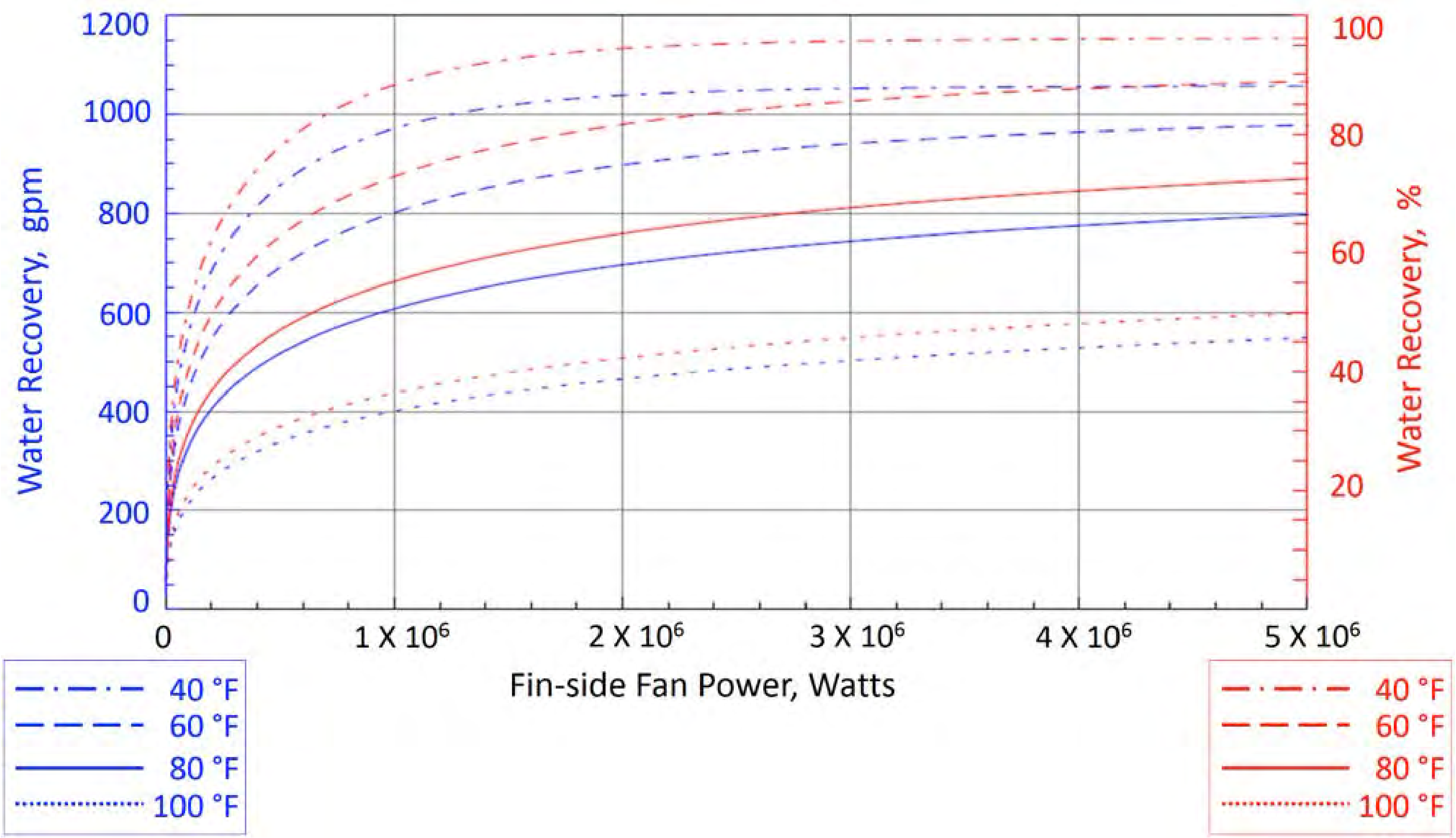
Fin depth = 1 ft.

Fin thickness = ¼ in.

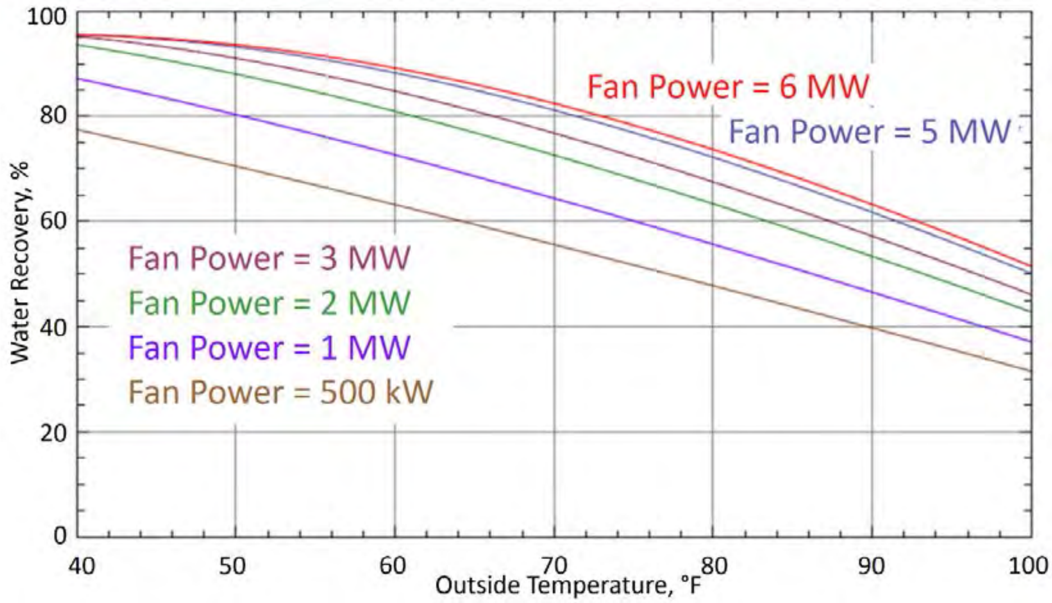
For Case A9, the water recovery as a function of fan power was estimated for different cooling air temperatures, as shown in Appendix Figure 4.12. The water recovery is expressed in gallons per minute or as a percentage of the water entering the system.

It can be observed in Appendix Figure 4.12 that the system tends to reach optimized water recovery values when the fan power is above 3 MW and the cooling air temperature is equal to or below 60 °F. In those cases, the system reaches water recovery efficiencies higher than 85 percent. Nonetheless, when the temperature is higher (80 °F), efficiencies achieved can be as high as 70 percent or more.

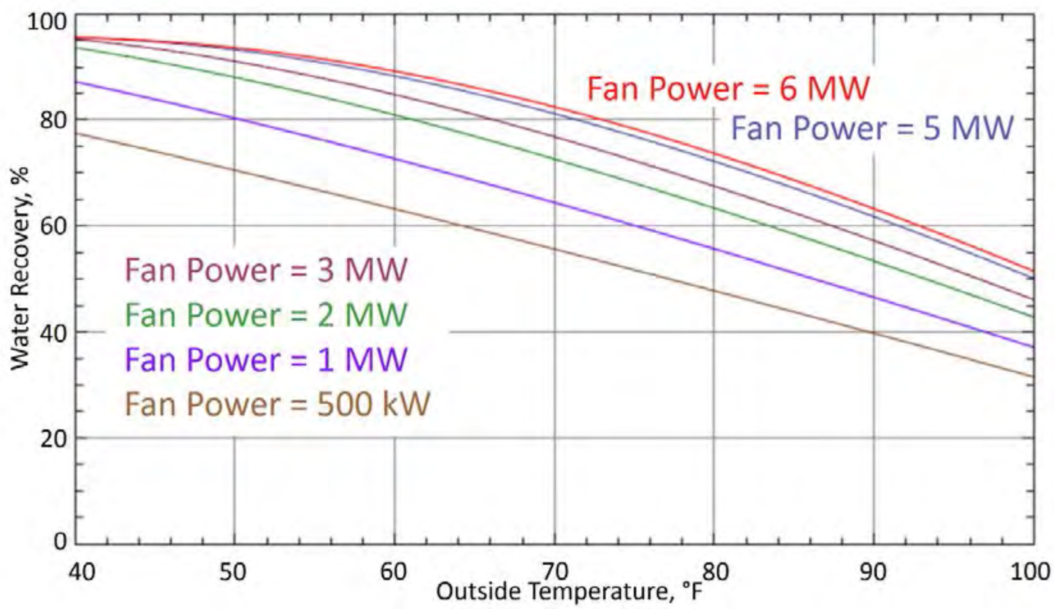
In Appendix Figure 4.13, the water recovery percentage is presented as a function of cooling air temperature for different fin-side fan power. As expected, higher cooling air temperature results in lower water capture, which reaffirms the results from Appendix Figure 4.12. The same results are shown in Appendix Figure 4.14, but the water recovery is expressed in gallons per minute.



Appendix Figure 4.12 Water recovery vs. fin-side fan power for Case A9.



Appendix Figure 4.13 Water recovery percentage vs. cooling air temperature for Case A9.



Appendix Figure 4.14 Water recovery in gallons per min vs. cooling air temperature for Case A9.

Case C9

The dimensions of the ESP channel for the proposed case are:

Length = 50 ft.

Height = 40 ft.

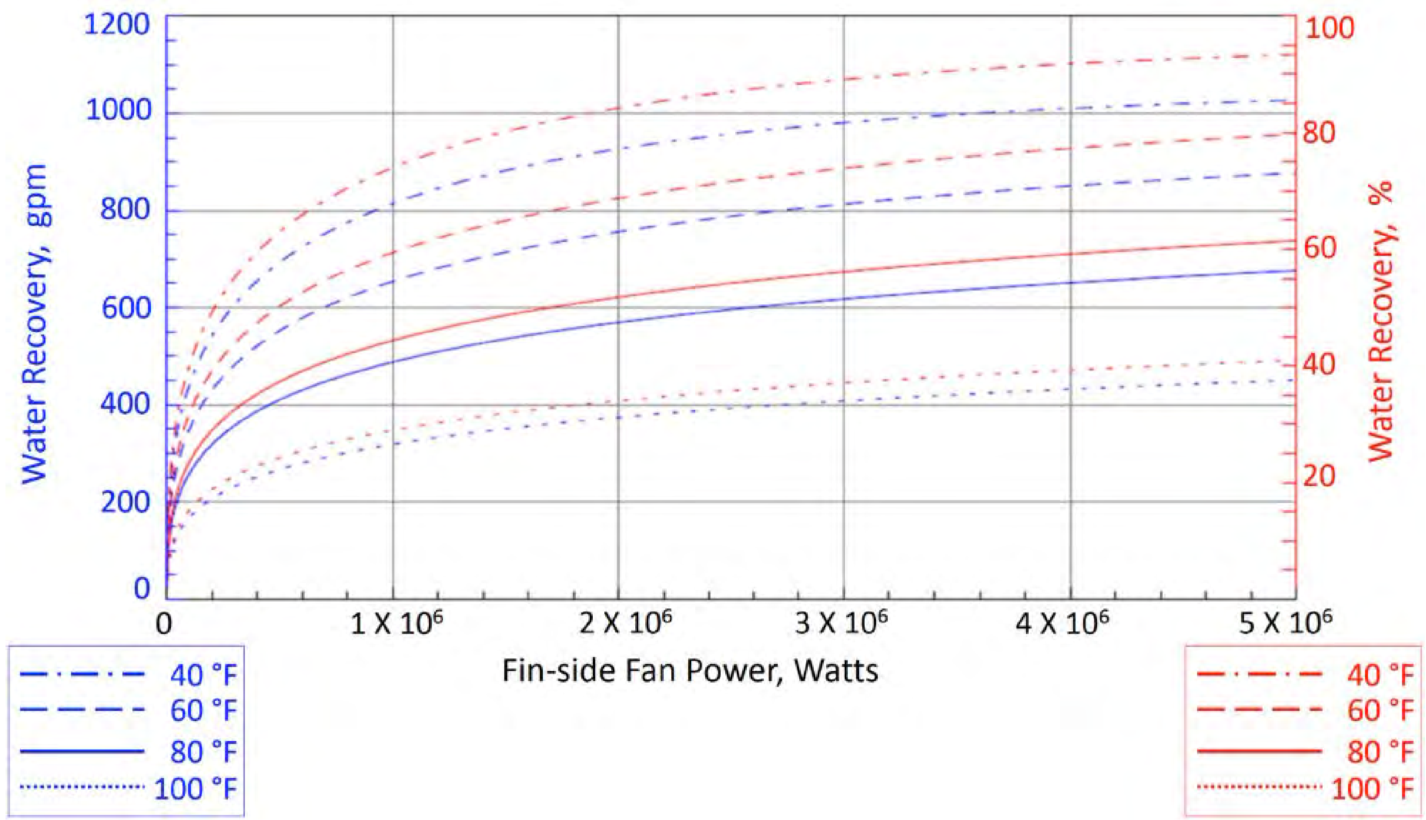
Width = 1.3 ft.

Number of ESP Channels = 60

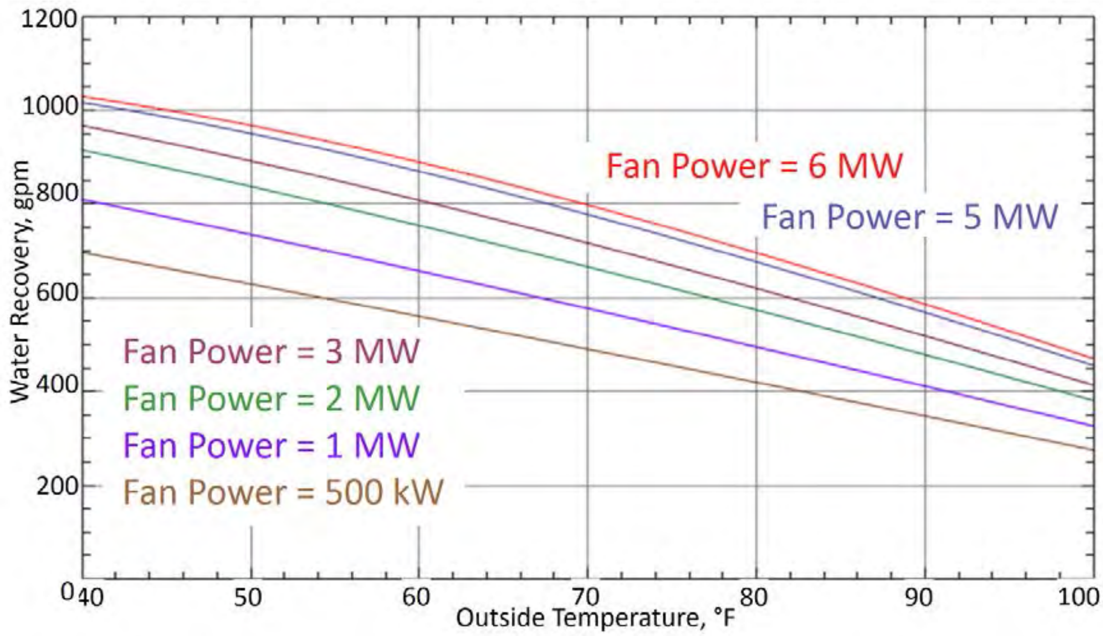
The fin configuration for this case is the same as Case A9. The results are first shown as water recovery as a function of fan power for different cooling air temperatures (see Appendix Figure 4.15). For this case, an optimized water recovery is not achieved; however, efficiencies as high as 60 percent are obtained for cooling air temperatures below 80 °F. A 60 percent water recovery represents around 700 gpm, which is about twice the amount of makeup water required for the FGD system of a typical 500 MW coal power plant. The water recovery plot against the cooling air temperature for various fan power is shown in Appendix Figures 4.16 and 4.17, expressed in terms of recovery percentage and gallons per minute, respectively.

In conclusion, the results indicate that, for both cases, the water recovery percentage increases when the cooling air temperature decreases. Nevertheless, high recovery percentages are obtained when the outside temperature is around 80 °F. Furthermore, at the same temperature, a large amount of water can be recovered using less than 1% of the plant's generation power (considering a 500 MW power plant). As presented in Appendix Table 4.12, the only difference between cases A and C, regarding design, is the number of ESP channels proposed for the system. This difference could have significant impact on the system's cost, but not on water recovery, since the amount of makeup water required for the FGD system is less.

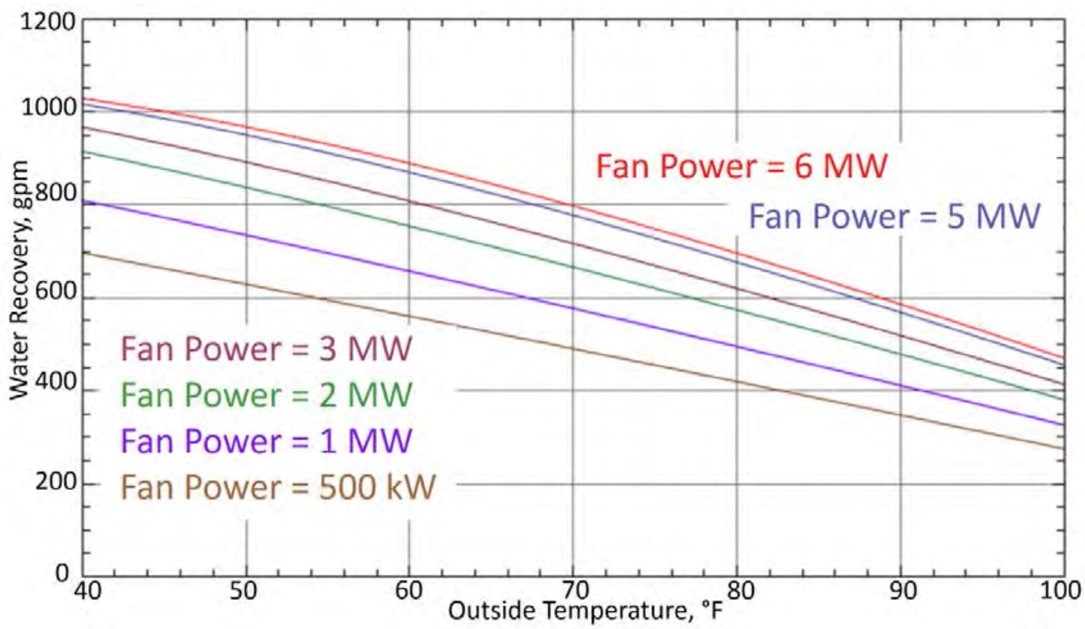
Also, optimization conditions are obtained when increasing the number of ESP channels and decreasing the cooling air temperature, as can be observed in Appendix Figure 4.12. With 60 ESP channels and a cooling air temperature of 40 °F, the maximum achievable water recovery percentage is around 95, with a fan power higher than 2.5 MW.



Appendix Figure 4.15 Water recovery vs. fin-side fan power for Case C9.



Appendix Figure 4.16 Water recovery percentage vs. cooling air temperature for Case C9.



Appendix Figure 4.17 Water recovery vs. cooling air temperature for Case C9.

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5 Natural Gas Electric Power Generation and Water Usage

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5.1 Introduction

Natural gas is the second most common fossil fuel used for electric power generation, accounting for 30% of total U.S. electricity production in 2012. Due to the relatively low natural gas prices, relative abundance of natural gas and capital costs, a natural gas plant is a more competitive choice for new generation capacity. According to EIA predictions in reference cases, natural gas power plants will account for 63% of electricity capacity additions from 2012 to 2040 (EIA, 2012).

Three aspects affect the use of natural gas in electrical generation: 1) the price of natural gas compared with other fossil fuels, especially coal, 2) the ability to mine the significant domestic reserves of natural gas, and 3) policies that reduce greenhouse gas (GHG) emissions. An example of one such policy is the 2014 performance standard that was proposed to restrict to 1,000-1,100 pounds of carbon dioxide per megawatt hour (MWh) for newly constructed coal and natural gas-fired power plants to curb their GHG emissions.[25]

Significant amounts of water are used in natural gas power plants, and other power plants in general. They require large volumes of water for the generation of electricity, primarily to turn turbines or for cooling in thermoelectric generation. Another use for water more specific to natural gas is the consumption of large quantities during the gas extraction process. Both uses greatly impact water resources, particularly freshwater, throughout the U.S.

5.2 Gas-fired Boiler Thermoelectric Plants

According to the EIA database, about 8.2 trillion cubic feet of natural gas was consumed as fuel for conventional steam turbines for electricity generation in 2013. This amount doubled the natural gas usage for electric power production since 1997. Electric power generated by natural gas-fired boilers reached nearly 3,112 MMBtu in 2010.

Natural gas-fired boiler steam turbines require cooling systems. Cooling system technologies have been improving steadily and have significantly decreased water usage in thermoelectric power plants over the past several years. Recirculating systems and recently developed dry cooling systems have been widely used in new thermoelectric power plants in place of once-through cooling systems. In particular, recirculating cooling technologies have been incorporated into about 200 newly constructed power plants built between 2000 and 2004,

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[25] See Chapter 2 of this report for further information regarding energy use trends.

including natural gas-fired boiler steam turbine thermoelectric plants. Water in circulating cooling systems is kept in a closed-loop and reused; thus, water withdrawals are lower compared to once-through processes. In dry cooling systems, air is used as a working fluid to lower the cooling water temperature instead of water. Due to the significant amount of electricity required for running cooling fans, dry cooling systems are more suitable for small scale plants and gas-fired power plants.

Among the 1,655 cooling systems in power plants that can each provide a combined net summer capacity of 100MW or more in the U.S., 674 cooling systems are employed by natural gas power plants. Of these, 422 (62.6%) are recirculating systems, while 197 (29.2%) are once-through systems. The rest (51) are mostly dry-cooling systems (7.6%) and 1 hybrid system, which can switch between wet and dry cooling (See Table 5.1)

Table 5.1 System types by primary energy source in 2012

Primary energy source	Once-through	Recirculating	Dry cooling	Wet & dry hybrid cooling	Total cooling systems
Coal	398	368	4	1	771
Natural gas	197	422	51	4	674
Nuclear	50	44	0	0	94
Other	74	41	1	0	116
Total	719	875	56	5	1,655

Note: Adopted from EIA (2012)

5.3 Gas Turbine and Boiler Cogeneration

Gas turbine power plants primarily use natural gas as an energy source, though synthetic gas from coal production can also be used within these plants. Gas turbine technology has steadily advanced in recent decades, and represents a new trend for electricity generation. The advantages of gas turbines include: 1) higher efficiency when used in a combine cycle configuration, 2) flexibility in being turned on and off to meet electricity demand, and 3) computer-based design and the development of advanced materials enable higher efficiency.

The basic configuration of gas turbines mainly consists of a compressor (either a centrifugal or axial), a combustion chamber, and a turbine integrated with an electrical generator. Different from steam turbines, gas turbines use air instead of water as the working fluid. After being accelerated by the compressor and slowed by a diffuser, fresh air flow is brought to a higher pressure and mixed with natural gas. The mixed gas is then ignited to combustion. The high-pressure and high-temperature gas produces shaft work output by expanding through the turbine.

The Brayton cycle is the ideal thermodynamic cycle typically used to represent gas turbine operation. The Brayton cycle contains the following three thermodynamic processes:

1. Isentropic compression: Air flow is drawn into the compressor and pressurized after acceleration through the compressor and deceleration through the diffuser.

2. Isobaric combustion: The mixture of compressed gas (air) and fuel (natural gas) is combusted under constant pressure to increase the specific volume.
3. Isentropic expansion: The heated, pressurized, larger volume gases are expanded through a turbine.

The exhaust products are then ejected at isobaric conditions from the turbine at the original pressure. In practical applications, energy losses occur during each process due to friction and turbulence. In order to fully expel the exhaust gases, some pressure still remains in the exhaust gases instead of returning it to the original pressure of the intake air.

The efficiency of a gas turbine is limited by the temperatures and mechanical stress that the engine materials can withstand. Due to the energy lost in the Brayton cycle and residual energy in exhaust gas, the thermal efficiency is as low as 35-40% for a single-cycle gas turbine that produces 100 to 400 MW of electric power (Cengel et al., 2011; Ratliff et al., 2007)

In electric power generation, a natural gas combined cycle (NGCC) configuration can significantly increase thermal efficiency of gas turbines, up to 60% according to some reports (Yuri et al., 2013; Hada et al., 2012; Uchida et al., 2012). A widely used configuration includes the use of one or more natural gas turbine generators and a heat recovery steam generator (HRSG), which is operated using the Rankine cycle by extracting energy from the hot exhaust gases generated by the gas turbine. In this manner, the steam generator is used to recover a significant fraction of waste heat from the gas turbine. The steam turbine of the HRSG is powered by high pressure steam and generates additional electricity. Low pressure steam exits to a cooling tower and is condensed to warm water to recharge the HRSG (See Figure 5.1).

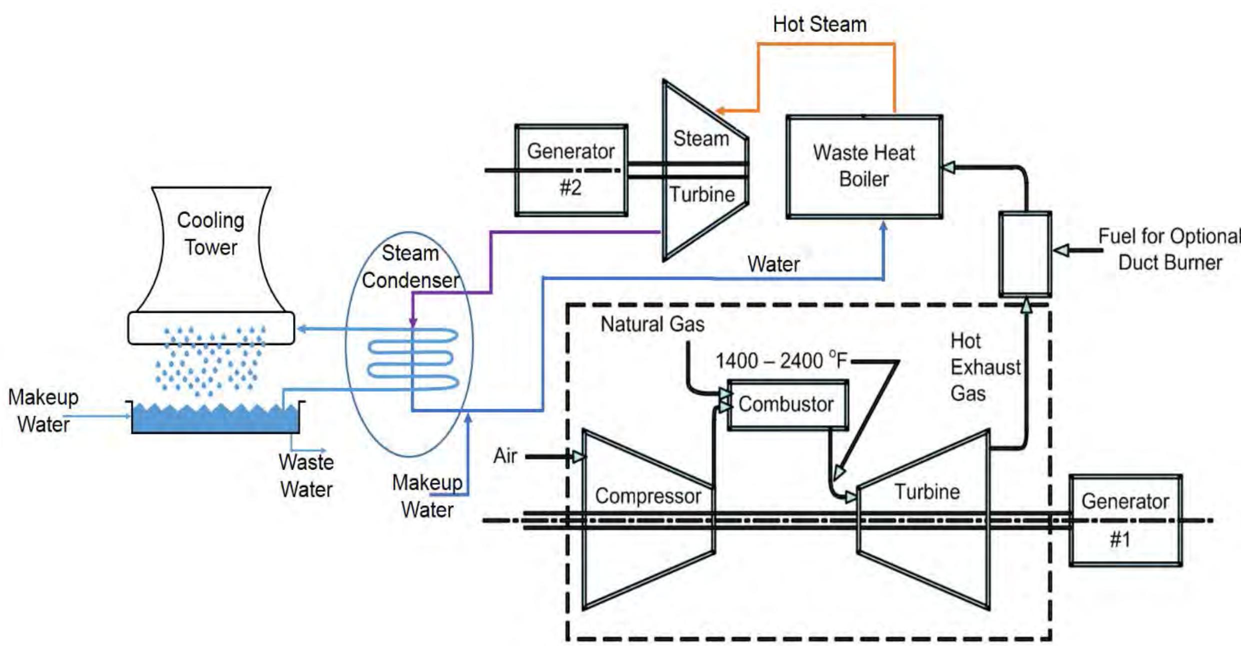

Figure 5.1 Schematic drawing of the gas turbine combined cycle power plant.

5.4 Water Usage

As described earlier, producing energy from fossil fuels such as natural gas often involves substantial amounts of water. Thermoelectric power plants generate power by boiling water to produce steam that drives electricity-generating steam turbines. Furthermore, large quantities of water are typically used to cool the steam to complete the power cycle. Thermoelectric power generation consumed nearly 196 billion gallons per day, primarily for cooling, in 2000. Approximately 70 percent of all thermoelectric water withdrawals are obtained from limited supplies of freshwater, accounting for nearly 40 percent of all freshwater withdrawals in the U.S. in 2000 (Dziegielewski, 2006). For natural gas electric power generation, water is used during power generation, but it is also used to extract the natural gas (e.g., enhanced gas recovery, coalbed methane extraction, and shale gas extraction) from its underground source.

5.4.1 Water usage for fuel extraction

Natural gas in the U.S. has typically been extracted via drilling deep vertical wells that require only relatively small amounts of water (UCS, 2013). However, on an overall basis, this method generates significant amounts of "produced water" (~ 200 billion gallons/year) (U.S. DOE, 2006; UCS, 2013). Produced water is generated from naturally occurring fluids in natural gas-bearing formations (U.S. DOE, 2009). Several methods have been developed for disposing of produced water, such as pumping it back into oil- or gas-producing wells to bolster production, or injecting it deep into other formations away from groundwater resources (UCS, 2013).

Over the past decade, the proportion of domestic natural gas production derived from shale gas (unconventional gas reservoirs) has significantly increased, primarily due to technological developments and innovations. As a result, the price of the natural gas has steadily decreased and shale gas has become a significant new source of natural gas in the U.S. "Hydraulic fracturing" or "hydrofracking" has improved the economics of accessing natural gas from shale deposits. The hydraulic fracturing process is schematically shown in Figure 5.2. Hydraulic fracturing of shale typically combines vertical drilling with horizontal drilling to follow gas deposits (UCS, 2013). A fracturing fluid consisting of approximately 90% water, 9% sand, and 1% chemical additives is injected into the gas deposits at high pressures and creates fractures in the surrounding rock, which allows the natural gas to flow to the production well and through to the wellhead where it can be collected for distribution (UCS 2013). In 2012, shale gas made up approximately 30% of total U.S. natural gas production, and is anticipated to grow to almost 50% by 2040 (EIA, 2012).

In spite of the economic advantages of increased shale gas extraction, there are several potential environmental risks from increased use of hydraulic fracturing. For example, groundwater could be contaminated with natural gas, volatile organic compounds and/or the chemicals used in the gas extraction process. A single hydraulic fracturing treatment has been estimated to yield 15,000 gallons of chemical waste from the fracturing fluids if not properly managed (Kenny et al., 2009). The quantity of produced water and sufficient treatment or reuse of produced water may also be challenging. While the total amount of water required for hydraulic fracturing is relatively small compared to the water withdrawn for thermoelectric generation or for agriculture, the amount of water required for hydraulic fracturing may still be

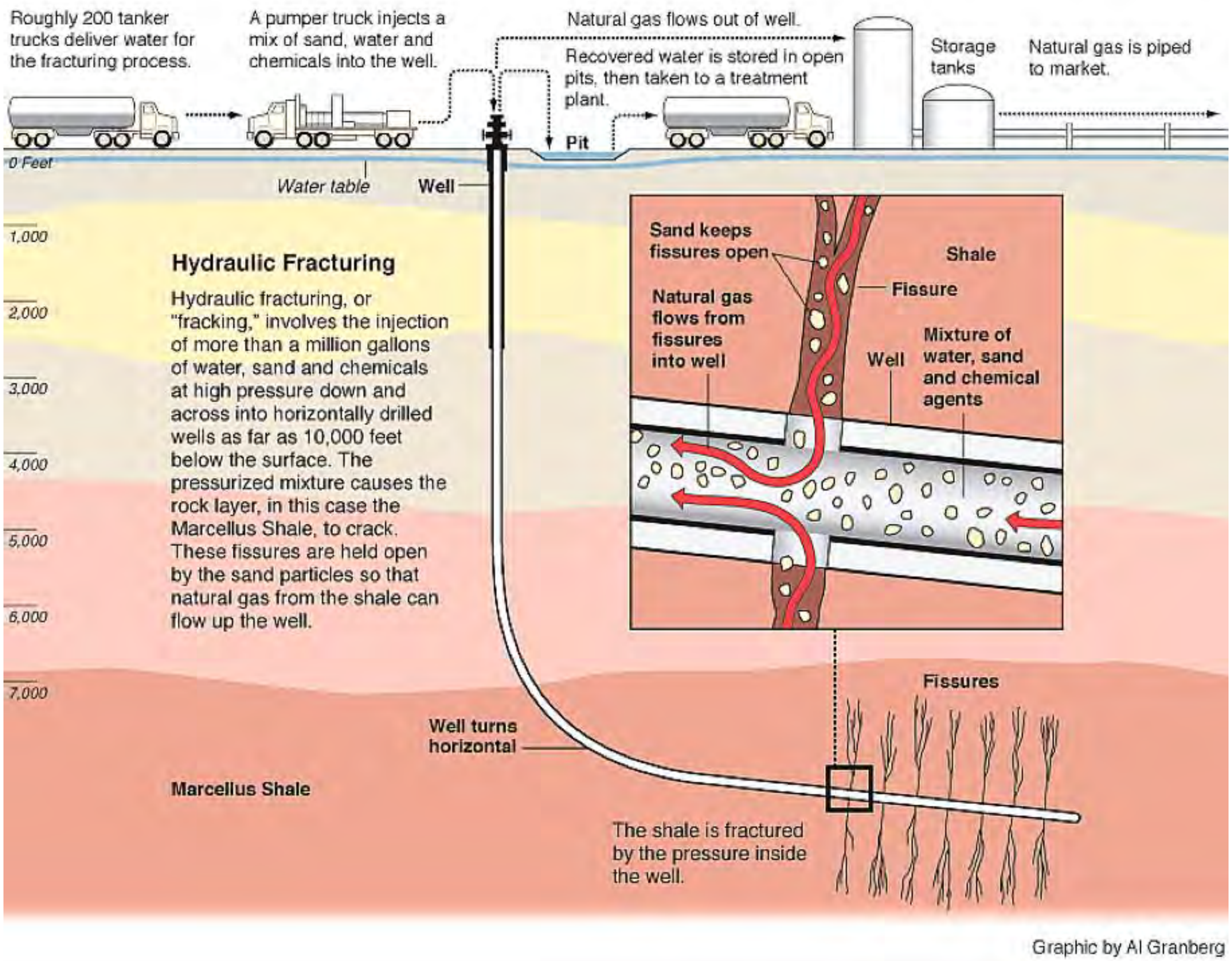

Figure 5.2 Diagram of hydraulic fracturing of natural gas. Adopted from Granberg,/ProPublica (2013).

regionally or locally significant since hydraulic fracturing wells are often not collocated with surface water sources (UCS 2013). Thus, local water sources could be adversely impacted depending on the natural gas well size, gas flow volume and duration, and number of other natural gas wells in a particular area.

5.4.2 Water usage for electricity generation

A majority of the natural gas-fired power plants in the U.S. are composed of natural gas combined-cycle (NGCC) units (EIA, 2012). NGCC power plants require lower quantities of water for cooling compared to conventional steam turbine technologies used in plants with natural gas-fired boilers or in coal or nuclear power plants (U.S. DOE, 2011). In a typical NGCC power plant, dry cooling systems are used, which are more economical and smaller (about 30%) than other thermoelectric options in a coal or nuclear power plant with the same electricity output (GAO, 2009). About 8% of natural gas combined cycle plants in the U.S. use dry cooling technology, while 80% rely on recirculating systems. Fewer than 7% use once-through cooling (Union of Concerned Scientists, 2013). Table 5.2 summarizes the water requirements for different types of natural gas power plants (Macknick et al., 2012; Union of Concerned Scientists, 2013).

Table 5.2 Water requirements for natural gas power plant in gal MW^{-1} h^{-1} *

	Once-Through		Recirculating		Dry-Cooling	
	Withdrawal	**Consumption**	**Withdrawal**	**Consumption**	**Withdrawal**	**Consumption**
Natural Gas Steam Turbine	10,000-60,000	95-291	950-1,460	662-1,170	0-4	0-4
Natural Gas Combined Cycle	7,500-20,000	20-100	150-283	130-300	0-4	0-4
Natural Gas Combustion Turbine	0	0	0	0	0	0

Note: * Union of Concerned Scientists, 2013: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-natural-gas.html.

Based on water sources or water intake processes, once-through cooling systems and recirculating cooling systems can be further grouped into the following subcategories (EIA, 2012):

- Once-through cooling systems:
  - OC: Once through, with cooling pond(s) or canal(s)
  - OF: Once through, freshwater
  - OS: Once through, saline water

- Recirculating cooling systems:
  - RC: Recirculating with cooling pond(s) or canal(s)
  - RF: Recirculating with forced draft cooling tower(s)

- RI: Recirculating with induced draft cooling tower(s)
- RN: Recirculating with natural draft cooling tower(s)

In general, water withdrawal for the thermoelectric power plants that use closed-cycle cooling systems is much less than those equipped with once-through systems. In 2005, recirculating cooling systems accounted for 8% of the total water withdrawal for thermoelectric power plants; once-through systems made up for 92% (Kenny et al., 2009). According to the EIA database for the year 2010, cooling water withdrawal ranged from 0.30 to 8.05 m^3 per 100MJ generation for the plants having once-through cooling systems. This value ranged from 0.004 to 0.32 m^3 per 100MJ electric generation for recirculating cooling systems, except those with cooling ponds or canals (See Table 5.3)

Table 5.3 Annual average withdrawal rate of cooling system for natural gas-fire steam turbine thermoelectric power plants

Cooling type	Annual average withdrawal rate (m^3/sec)			Cooling water withdrawal per generation ($10^{-2}m^3$/MJ)	Cooling unit, n
	Max.	Min.	Median		
OC	580.98	22.75	402.46	0.30 - 7.50	4
OF	1465.49	29.08	340.99	0.35 - 8.05	50
OS	325.89	182.33	269.00	1.50 - 7.11	6
RC	859.61	2.60	445.28	0.05 - 9.40	13
RF	65.60	2.20	7.10	0.04 - 0.32	28
RI	17.22	0.45	11.50	0.004 - 0.12	24
RN	37.58	19.02	37.58	0.20 - 0.21	3

5.5 Summary

Natural gas is currently the second most-used fossil fuel for electric power generation. Increased natural gas production through hydraulic fracturing, relatively lower prices of natural gas, improved thermal efficiency of combined cycle gas turbine power plants, and reduced carbon emissions make natural gas power plants an increasingly attractive option for new electric generating capacity when compared with coal-fired power plants. EPA recently proposed new GHG regulations for thermoelectric power plants, both new and old (see Chapter 2), which may result in further increased usage of natural gas for electric power production. Moreover, existing coal power plants are likely to stop increasing capacity. Thus, additional measures to reduce carbon emissions will compete with expanding natural gas electric power generation.

Water usage for natural gas power plants is an important factor to be considered in both evaluating the current and future electric power plants. Reducing water usage is a key objective to protect the environment and reduce costs. Natural gas prices have driven the recent expansion of its use in power plants. However, there are concerns regarding water usage and contamination from the process of acquiring it unless extraction processes and treatment of contaminated water are managed in a sustainable manner. New technologies for fuel extraction and cooling are essential to achieve the goal of minimal water use and the use of environmentally benign technologies. Dry cooling systems in NGCC power plants are one such example, and should be considered and used more often. NGCC power plants will result in a significant decrease in the overall water footprint of electric generation from fossil fuels as they replace older coal-fired power plants.

Coupled with the industry's expected shift away from coal, water usage will further decrease with new cooling technologies. The effects would be particularly significant in areas with power plants nearing retirement. Specifically, replacement of these plants with competitive and more efficient NGCC plants can reduce water consumption in water-stressed regions, or in regions with shared aquifers. Both policy and market trends may accelerate the increased use of natural gas within future electric power generation in the U.S., thus decreasing water withdrawals and improving water quality.

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6 Corn-Starch-Based Ethanol Production and Impacts on Water Resources

Wei-Ning Wang[i], Ying Li[i], and Pratim Biswas[i]

6.1 Introduction

Currently, ethanol constitutes approximately 93% and 91% of all biofuels produced 94% of all biofuels produced in the U.S. in 2012 and 2013, respectively (EIA, 2014). Greater qualities of ethanol are expected to be used as a transportation fuel in the future because of federal policies. For example, according to the Renewable Fuel Standard (RFS2), the volume of corn-starch ethanol is capped at 13.8 billion gallons in 2013, but grows to 15 billion gallons by 2015 and is fixed thereafter (Schnepf and Yacobucci, 2013).

At present, virtually all fuel ethanol in the U.S. is produced from fermentation of corn in dry and wet milling plants, most of which are located in U.S. Midwest states. In 2004, two-thirds of total fuel ethanol was produced from dry mill plants, and the remaining one-third from wet mill plants (Wang, 2005). Besides corn-based and sugarcane-based varieties, ethanol can also be produced from cellulosic biomass through fermentation of cellulose and semi-cellulose.

Federal policies mandating increased use of ethanol and other biofuels in transportation fuels may be hampered by the water issues faced in the corn-producing areas of the U.S. unless biofuel feedstock cultivation is transitioned to less water-intensive biomass crops, e.g., transitioning ethanol production from corn starch to a cellulosic feedstock such as switch grass[27]. The majority of the corn grown in the U.S. is in Midwest states and a number of corn-producing the states that rely on groundwater for irrigation, such as Iowa and Nebraska, are in regions where groundwater levels are falling. On a world-wide basis, the average consumptive water-intensity of ethanol is 1826 gallons-H_2O/gallon-ethanol, with 1260 gallons-H_2O/gallon-ethanol due to evapotranspiration and 566 gallons-H_2O/gallon-ethanol due to irrigation. Average water intensity of corn irrigation for ethanol production in the U.S. is lower on average than world-wide figures at 113 gallons-H_2O/gallon-ethanol and is highly variable, ranging from 15 to 934 gallons-H_2O/gallon-ethanol (King and Webber, 2008), depending upon regional differences in irrigation levels.

Previous studies and analyses have focused on overall net energy values (Farrell et al., 2006; Graboski, 2002; Shapouri et al., 2004; Wang, 2001) and net greenhouse gas (GHG) emissions of corn-starch-based ethanol (EPA, 2010; Pimentel and Patzek, 2005; Shapouri et al., 2004; Wang, 2001). However, less literature has been reported on the relationships between energy input, water consumption, wastewater discharge, and CO_2 emissions in the biorefinery phase (i.e., conversion of corn to ethanol in ethanol plants). Pimentel and Patzek reported that in the corn-to-ethanol process, 15 liters of water are mixed with each kg of corn, and to make 1 liter of 99.5% ethanol, an input of 40 liters of water is needed when not including cultivation or other needs (Pimentel and Patzek, 2005). Additionally, for each liter of ethanol produced, about 13

[i] Washington University in St. Louis

[27] Cellulosic ethanol production is discussed separately within Chapter 7 of this report.

liters of very high-strength wastewater are produced. While it is not certain whether this data took water recycling into consideration, other sources have reported much less water use when water recycling is applied intensively in plant operations.

The objective of the analysis contained within this chapter is to systematically evaluate water use in the post-cultivation ethanol production processes by studying ethanol production plants. The methodology applied is a mathematic modeling of the energy balance (including thermal energy and electricity) and the mass balance (including corn input, water usage, wastewater discharge, co-products and CO_2 emissions) with respect to the various process system boundaries. This analysis of corn ethanol production includes:

a. Construction of a mathematical model with an energy and mass balance for a typical corn-to-ethanol plant.
b. A summary of field visits to both pilot-scale and full-scale ethanol plants to gather first-hand ethanol production data.
c. A comparison of the different scales and successive generations of ethanol plants.
d. Recommendations for future research.

6.2 Energy and Mass Balance Model

6.2.1 Corn-to-ethanol production process overview

Based on a literature review and various internet resources (Agricultural Marketing Resource Center, 2001; ICM, 2007, 2014; National Corn-to-Ethanol Research Center, 2014; McAlloon et al., 2000; Renewable Fuels Association, 2014; Seekingalpha, 2014), a system diagram of the typical dry-mill corn-to-ethanol production process has been prepared (see Figure 6.1). The basic steps include milling, mashing, cooking, liquefaction, saccharification, fermentation, distillation/dehydration, solids separation, evaporation and drying. If the ethanol plant is taken as a single system, the overall inputs and outputs at the system boundary are shown in Figure 6.2. The inputs are corn and water plus energy, while the outputs are ethanol, solids (by-products), wastewater and CO_2. In this chapter, a detailed analysis of energy and mass balance calculations for each step in the process is presented.

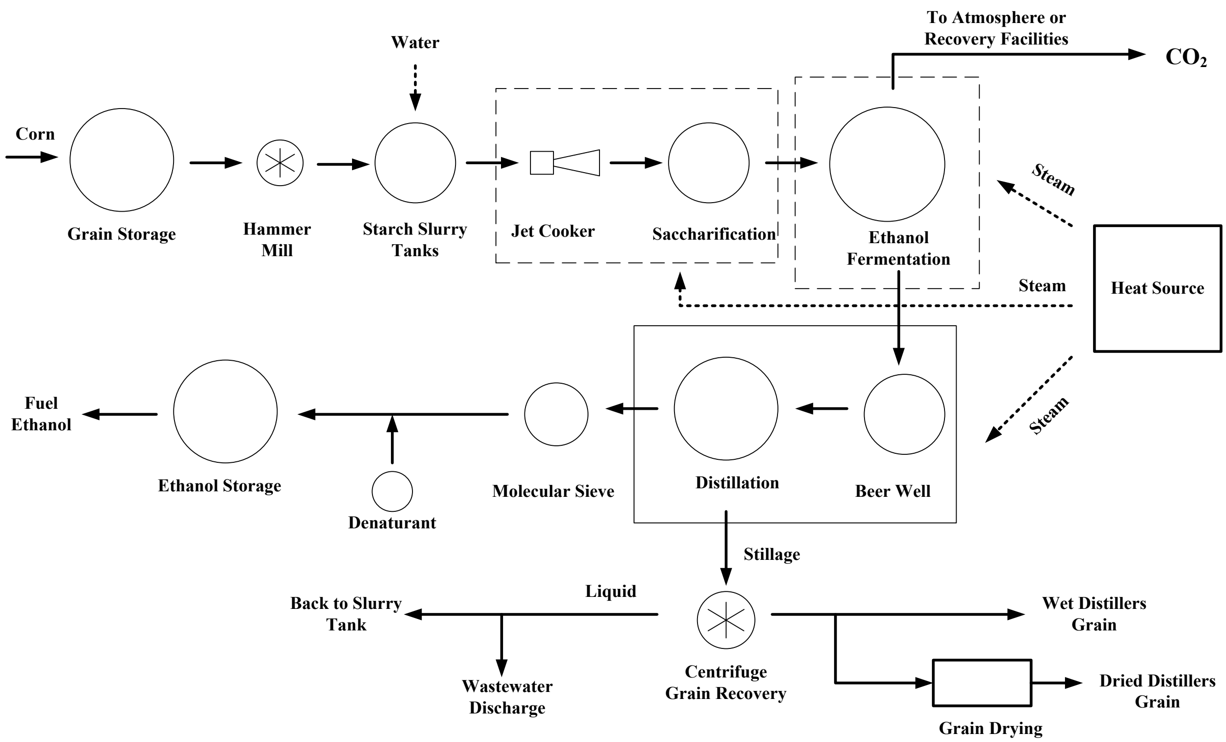


Figure 6.1 System diagram of typical dry-mill corn-to-ethanol production process.

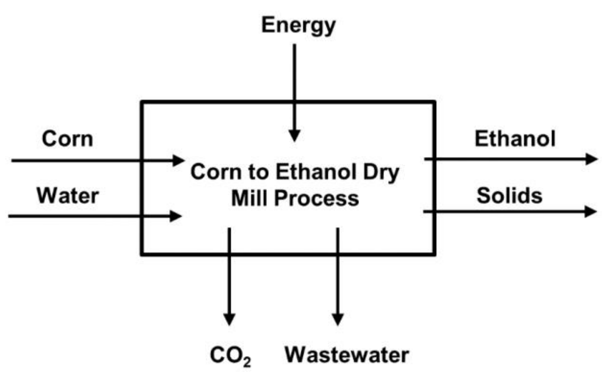


Figure 6.2 Inputs and outputs at the system boundary.

6.2.2 Mass balance model

To resolve the material balance for the corn-to-ethanol plant, the unit operations of a block flow diagram (BFD) must be defined (Mei, 2006). Figure 6.3 shows the BFD of a typical ethanol plant with all the basic steps included.

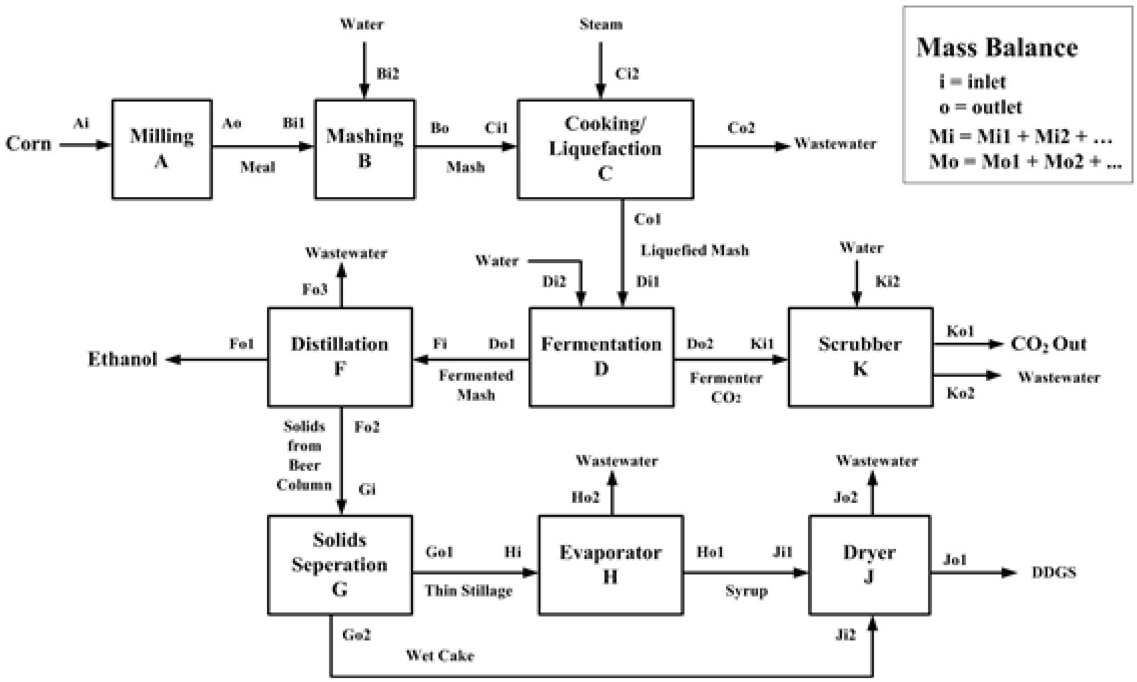


Figure 6.3 Mass block flow diagram of ethanol production process.

For each of the blocks, a material balance is written as:

Material in = Material out (6.2-1)

or $M_i = M_o$ (i = input; o = output) (6.2-2)

or $$\sum_{j=1}^{m} M_{i,j} = \sum_{k=1}^{n} M_{o,k} \qquad (6.2\text{-}1)$$

where j represents the type of material inputs with a total of m inputs, and k represents the type of material outputs with a total of n outputs.

The mass balance calculation starts with corn inputs. Table 6.1 lists the composition of corn (Mei, 2006). The starch (the actual material that makes ethanol) is then mixed with water and turns into glucose followed by fermentation and the production of ethanol. The reaction stoichiometry on a weight basis can be written as:

Starch + 0.1111 Water → 1.1111 Glucose (6.2-2)

Glucose → 0.4589 Ethanol + 0.4641 CO_2 + 0.05 other (6.2-3)

Table 6.1 Corn composition

Component	Mass Content %
Water	15.0%
Starch	59.5%
Protein	7.7%
Oil	3.4%
Other	14.5%
Total	100%

The yield of ethanol is a function of starch composition in corn, conversion efficiency of starch to glucose and conversion efficiency of glucose to ethanol. Assuming a 100% efficiency for both conversion processes, the typical yield is 2.5 to 2.85 gallons of ethanol per bushel of corn (Mei, 2006). In this model, an average value of 2.7 gallons of ethanol per bushel of corn is used as the corn-to-ethanol conversion rate. The CO_2 emission profile can also be calculated from equations 2-4 and 2-5 with a given mass of corn (or starch).

Based on the equations 6.2-1 to 6.2-5, the process data and assumptions derived from Mei (Mei, 2006), a spreadsheet-based mass balance model for the corn-to-ethanol production process was established (Wang et al., 2014). Figure 6.4 shows an example worksheet of the mass balance model.[28] The model requires the amount of corn in kilograms as an input (cell B3 in Figure 6.4). Based on the mass balance model illustrated in Figure 6.3, the model calculates the mass of materials that go into and come out of each of the steps (column B for input and column E for output in Figure 6.4) in the corn to ethanol production process (each box in Figure 6.3). The final output from the model includes the amount of water used to produce ethanol (cell J6 in Figure 6.4), and the amounts of ethanol (cell J8), carbon dioxide (cell J9), dry distiller grains with solubles (cell J10) and wastewater (cell J11) produced. It demonstrates that with 1 kg input of corn, 2.68 kg water is needed, and 0.32 kg ethanol and 0.33 kg dry distiller grains with solubles (DDGS) can be produced with 0.31 kg CO_2 emission and 2.72 kg wastewater discharge. It should be noted that this model assumes that no water recycling technology is applied.

[28] An example of the model may be accessed via the following Internet URL: http://www.aerosols.wustl.edu/education/energy/EthanolAudit/index.html

	A	B	C	D	E	F	G	H	I	J	K	L
1	A	Milling							Input			
2	Inlet			Outlet					Derived from Fan Mei, MS Thesis, 2006			
3	Corn, Ai	1.00	kg	Corn powder, Ao	1.00	kg						
4								Corn Feed		1.00	kg	
5	B	Mashing						Water Usage		2.68	kg	
6	Inlet			Outlet				Total Mass In		3.68	kg	
7	Corn powder, Bi1	1.00	kg	Mash, Bo	2.60	kg						
8	Water, Bi2	1.60	kg					Ethanol Out		0.32	kg	
9	Inlet total, Bi	2.60	kg	Outlet total, Bo	2.60	kg		CO2 Out		0.31	kg	
10								DDGS Out		0.33	kg	
11	C	Cooking/ Liquefaction						Wastewater Out		2.72	kg	
12	Inlet			Outlet				Total Mass Out		3.68	kg	
13	Mash, Ci1	2.60	kg	Liquefied Mash, Co1	2.67	kg						
14	Steam, Ci2	0.30	kg	Wastewater, Co2	0.23	kg						
15	Inlet total, Ci	2.90	kg	Outlet total, Co	2.90	kg						
16												
17	D	Fermentation										
18	Inlet			Outlet								
19	Liquefied Mash, Di1	2.67	kg	Fermented Mash, Do1	2.97	kg						
20	Water, Di2	0.61	kg	Fermenter CO2, Do2	0.31	kg						
21	Inlet total, Di	3.28	kg	Outlet total, Do	3.28	kg						
22												
23	K	Scrubber										
24	Inlet			Outlet								
25	Fermenter CO2, Ki1	0.31	kg	CO2 Emitted, Ko´	0.31	kg						
26	Water, Ki2	0.17	kg	Wastewater, Ko2	0.17	kg						
27	Inlet total, Ki	0.48	kg	Outlet total, Ko	0.48	kg						
28												
29	F	Distillation										
30	Inlet			Outlet								
31	Fermented Mash, Fi	2.97	kg	Ethanol, Fo1	0.32	kg						
32				Solids, Fo2	2.44	kg						
33				Wastewater, Fo3	0.21	kg						
34	Inlet total, Fi	2.97	kg	Outlet total, Fo	2.97	kg						
35												
36	G	Solids Seperation										
37	Inlet			Outlet								
38	Solids, Gi	2.44	kg	This Stillage, Go1	1.85	kg						
39				Wet Cake, Go2	0.59	kg						
40	Inlet total, Gi	2.44	kg	Outlet total, Go	2.44	kg						
41												
42	H	Evaporator										
43	Inlet			Outlet								
44	This Stillage, Hi	1.85	kg	Syrup, Ho1	0.36	kg						
45				Wastewater, Ho2	1.48	kg						
46	Inlet total, Hi	1.85	kg	Outlet total, Ho	1.85	kg						
47												
48	J	Dryer										
49	Inlet			Outlet								
50	Syrup, Ji1	0.36	kg	DDGS, Jo1	0.33	kg						
51	Wet Cake, Ji2	0.59	kg	Wastewater, Jo2	0.62	kg						
52	Inlet total, Hi	0.95	kg	Outlet total, Jo	0.95	kg						

Figure 6.4 Microsoft Excel™ spreadsheet worksheet for the mass balance model. Adopted from Wang et al. (2014)

6.2.3 *Energy balance model*

The energy needs for ethanol production is of great concern, and the availability of economical and reliable energy sources is essential for stable operation of the facility. We have performed a literature review on the total energy consumption of the corn-to-ethanol process, as listed in Table 6.2. The reported energy consumption varies significantly from 40,850 to 75,118 Btu/gal, with an average of 53,750 Btu/gal. Pimentel et al. (2007) estimates are over 30,000 Btu/gal higher than Wang et al. estimates, and over 20,000 Btu/gal higher than the average value of all the studies (Wang, 2001). This is because of Pimentel's inclusion of energy expended on capital equipment and energy for steel, cement and other materials used to construct the ethanol plant - components that were not included in most other studies. In this study, we used the average value from literature, 53,750 Btu/gal, as the basis of our energy balance calculation.

Table 6.2 Total energy consumption for corn-to-ethanol process

Literature	Ethanol Conversion Process (Btu/gal)
Pimentel and Patzek (2005)	54684
Pimentel et al. (2007)	75118
Lorenz and Morris (1995)	53956
Wang et al. (1999)	40850
Shapouri et al. (2004)	51779
Mei (2006)	46114
Average Total Energy Demand	53750 (Btu/gal) or 15.0 MJ/L

Generally, energy demand for an ethanol plant consists of thermal energy and electricity. Thermal energy is used to produce steam, which can be used for cooking, liquefaction, ethanol recovery and dehydration. Natural gas thermal energy is used for drying and stillage processing. Electricity is used for grinding and running electric motors. Figure 6.5 shows the diagram of energy flow through the corn-to-ethanol plant.

A general energy balance equation for each individual block can be written as:

Energy Input = Energy Output (6.2-4)

Or $$\sum_{\substack{input\\streams}} E_j + Q + W = \sum_{\substack{output\\streams}} E_j \qquad (6.2\text{-}5)$$

where E_j represents the total rate of energy transported by the j^{th} input or output stream of a process, and Q and W are defined as the rate of flow of heat and work into the process.

The energy balance calculation procedure is adapted from Mei (Mei, 2006) and the results are summarized in Table 6.3. For an ethanol conversion process, the majority of the energy is used as thermal energy for cooking, liquefaction, distillation and drying. Electricity is mainly used for milling, distillation and drying processes.

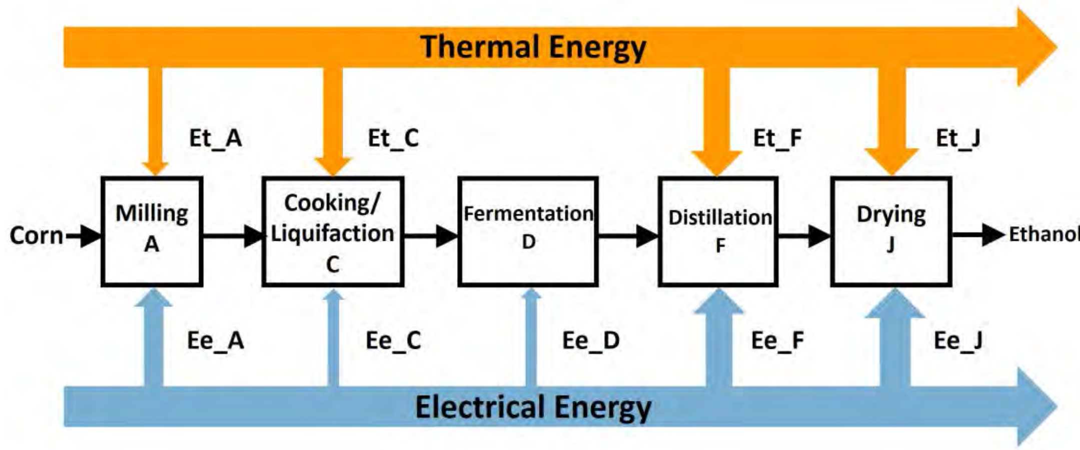


Figure 6.5 Energy block flow diagram of ethanol production process. Labels: Et – thermal energy; Ee – electricity energy.

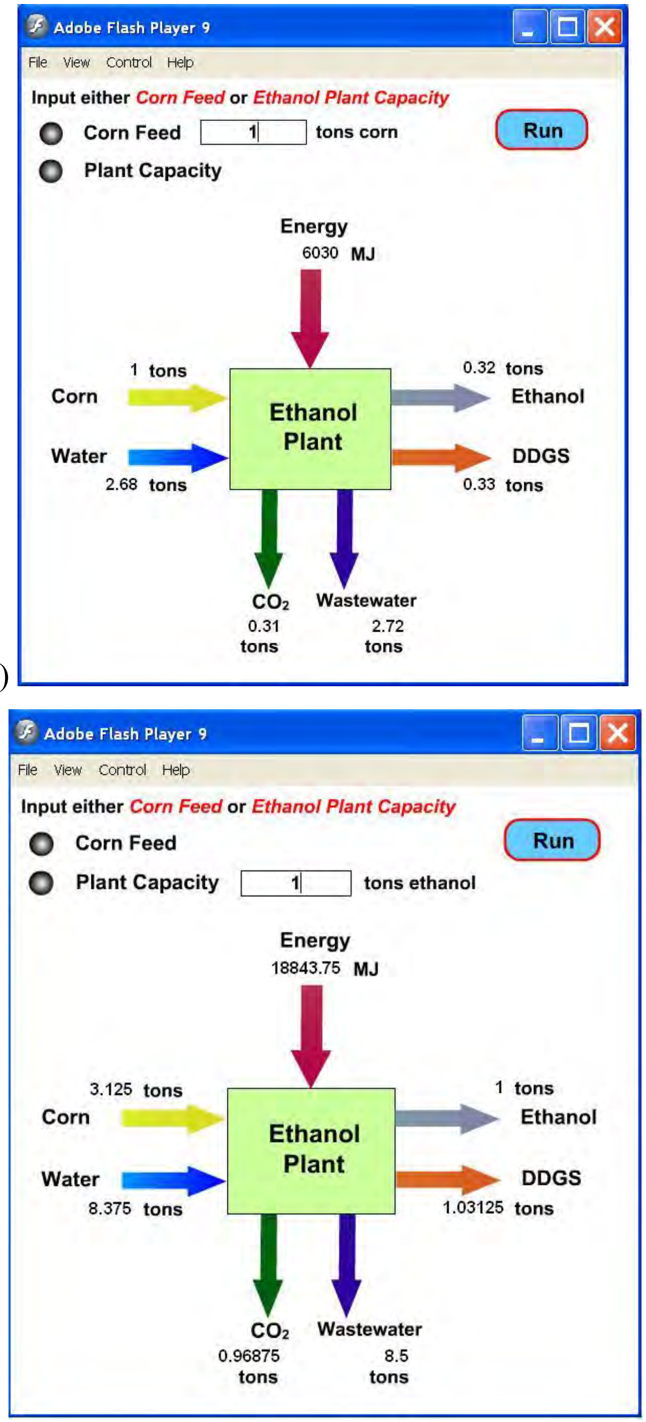
Table 6.3 Energy flow in corn-to-ethanol process

Energy Flow	Thermal Energy (MJ/L)	Electricity Energy (MJ/L)
A - Milling	0.21	0.10
C- Cooking/Liquefaction	2.81	0.06
D - Fermentation	-	0.06
F - Distillation	4.76	0.37
J - Drying	6.22	0.41
Total	14.0	1.0

6.2.4 Flash-based interactive model

Washington University in St. Louis developed an interactive model integrating mass and energy balance at the ethanol plant system boundary using Adobe Flash™. Flash™ is a popular multimedia software that can create animation and add interactivity to web pages. As shown in Figure 6.6, the users of this Flash-based model have two options to start mass and energy balance calculations by inputting either corn feed or ethanol plant capacity. For example, as shown in Figure 6.6(a), if the user chooses "Corn Feed" as the input method, an input text box will show up and allow the user to type in the amount of corn that will be fed to the plant. Then by clicking the "Run" button, the model will calculate and display the amounts of water and energy needed for the process, the amounts of ethanol and DDGS that will be produced, and the amount of wastewater and CO_2 that will be generated and emitted, if no controls are installed. Similarly, as shown in Figure 6.6(b), if the user chooses "Plant Capacity" as the input method, after typing in the amount of ethanol that a plant is expected to produce, the model will calculate and display the amount of corn, water and energy needed, as well as the amount of co-products and emissions that would be generated. The user friendly interface and the interactive feature make this model a handy tool for researchers, plant managers, policy makers and the public to understand the overall energy and environmental impact of the ethanol production process.

(a)



(b)

Figure 6.6 Flash-based interactive model on energy and mass balance – calculation based on (a) corn feed and (b) ethanol plant capacity. Adopted from Wang et al. (2014).

6.3 Pilot Scale Results

6.3.1 Background

Washington University in St. Louis studied the operations at the National Corn to Ethanol Pilot Facility established at the Southern Illinois University at Edwardsville (SIUE) campus. The purpose of this evaluation was to systematically identify the environmental and energy impacts of the various processes in ethanol production. This included determination of the water consumption, wastewater constituents, energy use, CO_2 output and material input/output. This information was used to understand key operations and their impacts on environmental considerations.

6.3.2 Production process overview

The National Corn to Ethanol Research Center (NCERC) is located on the campus of SIUE. The NCERC is a not-for-profit research center focused on the validation of near-term technologies for enhancing the economics and sustainability of renewable fuel production. The facility has all of the unit operations and laboratory capabilities of a commercial facility but on a much smaller scale. This is ideal for examining process parameters.

The examination of production processes at NCERC focused on the dry grind ethanol process. The pilot process is located in a 24,000 square foot complex. The scale of the operation is approximately $1/250^{th}$ of a full-scale operation. The facility can process 100 to 400 bushels per day of corn feed stock, and is capable of running in a batch or continuous mode. The process operations of the facility are similar to full-scale operations. Figure 6.7 provides an overview of the process operations. As can be seen in this diagram, the process operations include the same unit operations as full-scale operations.

The entire operation is equipped with online monitoring and controls to analyze the process parameters and keep historical records. Our review of this operation has shown that the utility and environmental parameters are similar to those found in literature with the exception of the water balance. The NCERC has the option of directing its process wastewater to an onsite treatment system. For testing purposes, makeup water is routinely provided using city water instead of recycled process water. This was advantageous since it allows the wastewater to be sampled. Other process parameters where considered as the overall mass balance evaluation was prepared.

6.3.3 Wastewater sampling and analysis

Figure 6.7 shows an example of the process control system looking at the inputs and outputs for the process water tank. This analysis only considered the dry-mill process. A careful review of the plant identified the following major operations:

- Milling
- Mashing
- Cooking/Liquefaction
- Fermentation
- Distillation
- Solids Separation

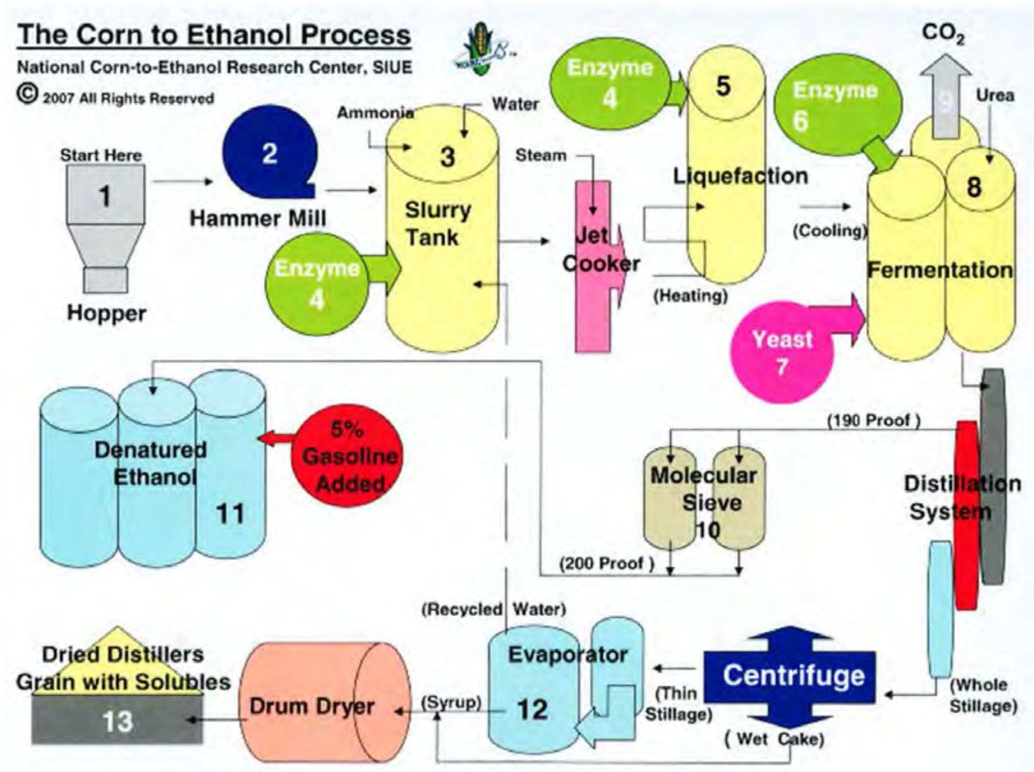


Figure 6.7 NCERC process flow diagram. Courtesy of SIUE.

Additional operations included boiling, evaporation and drying. The pilot facility recycled the condensate from the cooking/liquefaction and the distillation processes back into the mashing tank. These are potential wastewater sources; however, the flow is minor, and good design will normally route these streams as condensate water back into the mashing tank. Figure 6.8 shows the wastewater streams at this plant, and Figure 6.9 identifies the four locations chosen for wastewater sampling. The locations sampled are:

- Location A – CO_2 Scrubber
- Location B – Dryer
- Location C – Evaporator
- Location D – Thin Stillage

It should be noted that the thin stillage discharge is from the centrifuge and continues through the evaporator. This was a side stream sample taken to obtain a wastewater profile. The wastewater sample collection and analysis was conducted by American Bottoms Regional Wastewater Treatment Facility (ABRWTF), which is a municipal wastewater treatment agency located in Sauget, Illinois. They have an extensive pretreatment program due to the large amount of industrial flow, and are fully trained and equipped to conduct wastewater sampling.

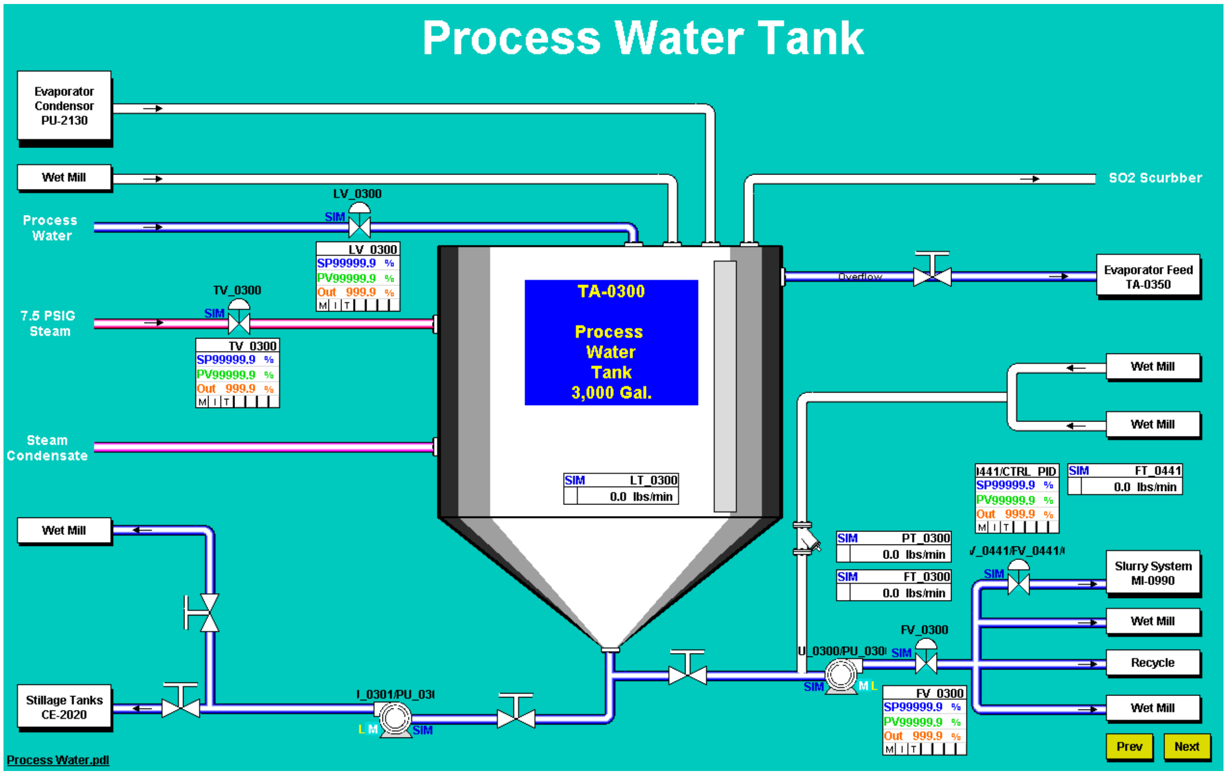


Figure 6.8 Process water tank flow scheme. Courtesy of SIUE.

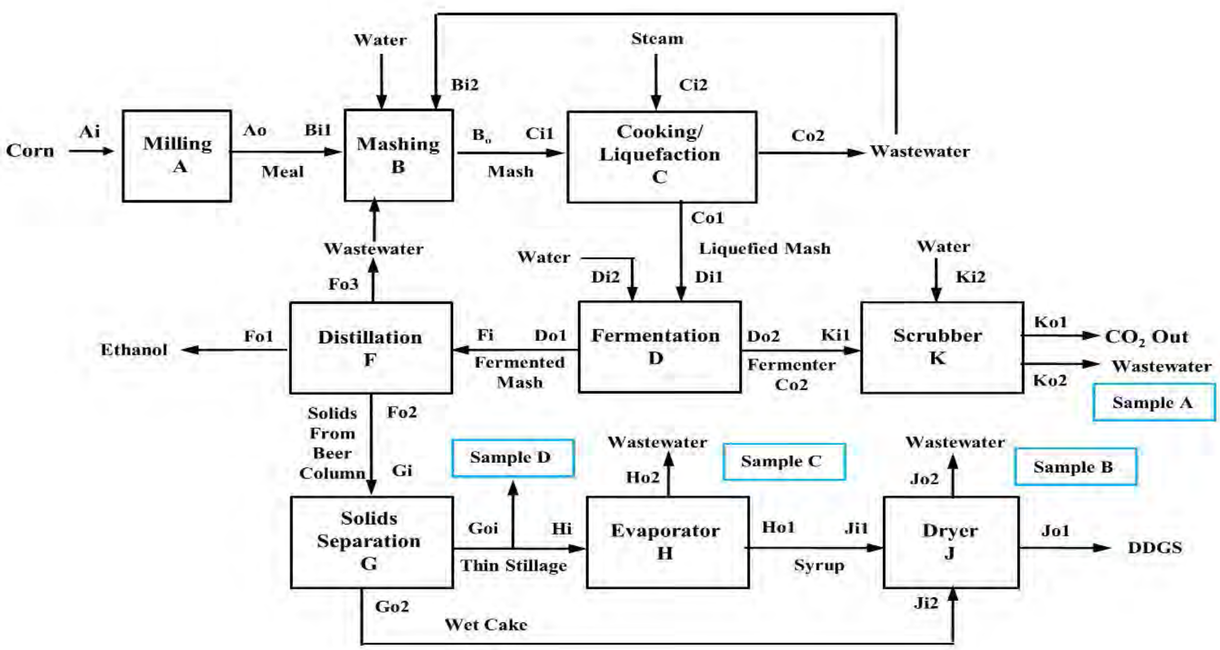


Figure 6.9 Wastewater sampling locations.

The wastewater parameters tested for included the following:

1. Volatile organics
2. Semi-volatile acid and base/neutral
3. Metals (Cd, Cu, Zn, Mn, Pb and Fe)
4. Mercury
5. TKN-N and NH_3-N
6. NO_2-N, NO_3-N and Ortho-P
7. Total Suspended Solids (TSS) and Total Dissolved Solids (TDS)
8. Chemical Oxygen Demand (COD)
9. Biological Oxygen Demand (BOD)

The BOD/COD, the key indicator of wastewater strength, for all of these samples were very high, as expected. The thin stillage sample indicates that it is not recommended to handle it separately, and a process of subsequent evaporation and drying is necessary. Recycling of scrubber water, evaporator water and dryer water back to the mashing operations appears to be a viable option. The pilot plant does not recycle these flows in order to maintain consistent data in their pilot test runs. A review of full-scale facilities shows that recycling of these flows is a common practice. Treatment and discharge or discharge to a municipal sewer would be considered costly to remove the high-strength organic waste or pay surcharges to the municipal wastewater authority.

6.4 Full-Scale Plant Review

6.4.1 Overview

Subsequent to the evaluation of the dry grind ethanol process described in Chapter 7, the project team contacted and visited a full-scale ethanol plant to quantify specific inputs and outputs achievable from modern ethanol plants. With the explosive growth of ethanol facilities in the U.S. since the passage of the Energy Policy Act of 2005, ethanol use has grown from 25 billion gallons in 2004 to over 100 billion gallons in 2010, rising to 120 billion gallons by 2014 (EIA, 2013). As more plants have been constructed, plant efficiency has significantly improved.

This section summarizes full-scale data collected from operating ethanol plants. Specifically, staff were interviewed at a new ethanol plant which launched operation in April, 2008. The staff reported current plant operating data, including corn to ethanol conversion rate, total water use, total wastewater produced, thermal and electrical energy required and CO_2 output.

6.4.2 Full-scale plant description and operation

The new ethanol facility that was evaluated is located in southern Illinois. Construction of the facility began in October, 2006, and ethanol production began in April, 2008. The facility uses the dry milling process to produce approximately 54 million gallons per year of ethanol, but can be expanded up to a total plant production of approximately 108 million gallons per year. The facility will use approximately 19 million bushels of corn annually. In addition to the ethanol, plant staff expects the facility to produce 172,000 tons of dry distiller grain and 150,000 tons of CO_2 annually.

These additional plant outputs have considerable value. The dry distiller grains are now sold as a replacement for corn in livestock feed. Given the higher costs of corn as the result of the increase in demand from new ethanol plants, the dry distiller grains provide livestock owners with a method to minimize their increased feed costs. In addition, the commercial-grade CO_2 produced during the fermentation process can be captured, cooled and stored, and then sold into the commodity market.

Much of the improvement in plant performance is being driven by the high costs and volatility of the primary plant inputs, along with increased industry output. The twin impacts of increased production capacity and higher raw material costs contributed to a significant drop in ethanol prices, suggesting that the building boom of 2005 and 2006 has ended (Jessen, 2007; Shirek, 2007). Corn prices have more than tripled this decade from around $2 per bushel to over $7 per bushel, and the volatility of natural gas is well-known. Thus, there is considerable market pressure on producers to operate the plants as efficiently as possible.

The project team's analysis of plant operations suggests that plant efficiencies are improving. A summary of the plant's operating parameters as of August, 2008, after four months of operation is presented on Table 6.4.

The total energy use is overwhelmingly from thermal processes (i.e., steam), which is used to heat the mixture. There is a modest amount of electricity used for pumping and air handling, but this accounts for less than 10 percent of the total plant energy inputs on a per gallon of ethanol-produced basis. The wastewater generated by the facility is primarily cooling tower and boiler blow-down. Water used for processing is recycled within the process and generally not discharged to the wastewater stream. In fact, process wastewater (which includes blow down) accounts for only about 25 percent of overall water use within this facility. The remaining water use within the facility is used for cooling, and exits the plant as water vapor from the cooling tower.

Table 6.4 Summary of operating parameters from a Midwest, full-scale ethanol production facility

Corn to Ethanol Conversion Rate	2.8	Gal ethanol per bushel of corn used
Total Water Use*	8.4 3.0	Gal water per bushel of corn used Gal water per gal ethanol produced
Total Wastewater Produced	2.1 0.75	Gal wastewater per bushel of corn used Gal wastewater per gal ethanol produced
Total Energy	100,800 36,000	Btu per bushel of corn used Btu per gal ethanol produced
Distilled dry grains produced	18	Lbs per bushel of corn used
Carbon dioxide	18	Lbs per bushel of corn used

Note: * Only accounts for water used by the facility to convert the corn into ethanol.

6.4.3 Assessment

ICM, Inc. is a Wichita-based company specializing in the development and application of ethanol processing technologies and has transitioned into a turnkey supplier to the ethanol industry. The company's proprietary process accounted for 2.1 billion gallons per year of the total 5.8 billion gallons per year of ethanol produced in the U.S. as of March, 2007. The project team contacted ICM to ascertain the future for potential improvements to the operation of ethanol plants in the U.S.

The company currently offers a performance guarantee of 2.8 gallons of denatured ethanol per bushel of corn (U.S. No. 2 Yellow Dent). Further, they guarantee that plant natural gas usage will not exceed 32,000 BTU per gallon of ethanol produced, and this value includes any gas used to dry the distilled solids. Also, the guarantee includes a limit of 0.75 kW of electricity per gallon of ethanol produced, which represents about a 15 percent improvement over the performance reported by the operating facility in Illinois (see section 2).

After corn, energy is a facility's primary expense, so there are market forces at work to minimize energy use. However, heat is essential to the fermentation and distillation processes, and so a minimum amount is needed. A typical, modern ethanol facility will use heat exchangers to capture and reuse heat throughout the plant, as suggested in Figure 6.10.

Figure 6.10. Heat capture through heat exchangers greatly improves energy efficiency in the Illinois ethanol plant.

Minimizing water use is also of great interest to ethanol producers. Technology is available to build ethanol plants capable of achieving zero discharge, and such facilities make permitting easier to complete, especially during expansions. However, in many locations zero discharge is not necessary and a number of existing ethanol plants use local groundwater sources, which are finite. In those cases, alternative water sources must be investigated, particularly in water-stressed regions. These can include lower quality surface waters or gray water. Firms that specialize in water treatment for the ethanol industry suggest that a 30 percent reduction in water use at ethanol plants is achievable. That level of reduction will be essential if larger ethanol plants are built, and if the industry is to expand in any significant way outside of the Midwest—particularly to the water-stressed regions of the Southwestern U.S.

6.5 Summary and Future Work

6.5.1 Summary

In 2013, ethanol constituted approximately 91% of all biofuels produced in the U.S. A majority of this ethanol is currently produced from corn starch. However, a potential drawback of producing ethanol from corn starch is the amount of water used to produce feedstock from corn cultivation. The irrigation of corn for ethanol production has a water-intensity that is an order of magnitude higher than the average water intensity for producing ethanol from corn starch, 113 gallons-H_2O/gallon-ethanol vs. 13.4 gallons-H_2O/gallon-ethanol (King and Webber, 2008) and thus needs to be taken into consideration separately from other stages of the production process. Irrigation requirements vary widely by state and region. Adaptive planning and future research investigating water use for corn ethanol production must take this regional variation into account. The consumptive water losses by evapotranspiration from corn cultivation for ethanol should also be carefully considered in any future analyses of water use in the production of ethanol. A potential alternative to corn ethanol is to transition to less water-intensive biomass crops for the feedstock such as alternative corn varieties that use less water for irrigation, alternative sugar/starch crops or cellulosic feedstock such as switch grass. Cellulosic energy crops on average have an irrigation water-intensity of approximately 25% of the irrigation water-intensity of ethanol (Tidwell et al., 2011).[29]

The first phase of this work as presented in this report has resulted in a detailed review of ethanol production from corn as a feedstock. Mathematical models that can be readily used by design engineers and auditors have been created. Detailed review of a pilot-scale facility and a full-scale plant were conducted. The key focus areas in this chapter were the use of energy for production of ethanol, the water usage (both quantity and quality) and the CO_2 emissions. The analysis was restricted to mass and energy balances around the plant.

A theoretical model on mass balance and energy balance for the dry mill corn-to-ethanol production process was established in this work. The inputs of the model are corn and water plus energy, while the outputs are ethanol, solids (by-products), wastewater and CO_2. The model was presented in two ways: an Excel Spreadsheet and a Flash-based interactive interface. The Excel-based model gives details of the mass and energy balance calculations for each step in the ethanol production process, while the Flash based model describes the overall inputs and outputs at the system boundary, and has the option to start the mass and energy balance calculation by inputting either corn feed or ethanol plant capacity. The user friendly interface and the interactive feature make this model a handy tool for researchers, plant managers, policy makers

[29] See Chapter 7 for further discussion of cellulosic ethanol production.

and the public to understand the overall energy and environmental impact of the ethanol production process.

Assuming no water recycling in the process, the model demonstrates that with 1 kg input of corn, 2.68 kg water is needed, and 0.32 kg ethanol and 0.33 kg DDGS can be produced with 0.31 kg CO_2 emission and 2.72 kg wastewater discharge. Note that the theoretical model was derived from Mei (Mei, 2006), which aimed to optimize the design of a 30 MMgpy corn-to-ethanol facility. Hence, this model is appropriate to represent a full-scale facility, except it does not account for wastewater reuse.

Surveys of larger scale ethanol facilities were later conducted to provide reference data to the theoretical model. We first studied the operations at the National Corn to Ethanol Pilot Facility established at SIUE. This facility has all of the unit operations and laboratory capabilities of a commercial facility but on a much smaller scale (approximately 1/250th of a full-scale facility). The operation process of the pilot-scale facility was similar to that described in the theoretical model, and makeup water was routinely provided using city water instead of recycled process water. Wastewater was sampled at four locations: CO_2 scrubber, dryer, evaporator and thin stillage. The analysis showed the BOD/COD for all these samples were considerably high, as expected. The pilot plant did not provide any data on the amount of energy consumed and wastewater discharged; however, recycling of scrubber water, evaporator water and dryer water back to the mashing operations appears to be a viable option.

Secondly, a full-scale new ethanol facility located in southern Illinois was evaluated. This facility uses the dry milling process to produce approximately 54 MMgpy ethanol using approximately 19 million bushels of corn annually. In addition to the ethanol, plant staff expects the facility to produce 172,000 tons of dry distiller grain and 150,000 tons of CO_2 annually. The water used for processing in the facility is recycled within the process and generally not discharged to the wastewater stream. The wastewater generated by the facility is primarily cooling tower and boiler blow-down. They also reported a smaller value of energy consumption compared with the theoretical model because they have used a series of heat exchangers for heat capture, and thus enhanced plant energy efficiency.

Minimizing water and energy use is of great interest to ethanol producers. Comparisons of the results from the literature review and surveys of different scales of ethanol facilities indicate the trend of improved energy efficiency and wastewater reuse rate for modern corn-to-ethanol facilities. On the other hand, the high rate of wastewater reuse means that the discharge could have high concentrations of heavy metals, BOD, TOC, etc., which have to be removed. The ethanol plants usually replace the entire stock of processing water after a certain amount of time so that the contaminants would not build up to impose any potential hazardous effects. So far, there is no standard operational reference or indicator to guide the practice of wastewater reuse for ethanol plants. Analysis of wastewater streams from full-scale facilities would lead to a better understanding of their potential reuse rate and treatment. In many locations, however, zero discharge is not necessary and a number of existing ethanol plants use finite local groundwater sources. In those cases, alternative water sources must be investigated. Currently, ethanol processed from corn starch uses 2.7 – 40 gal water/gal ethanol, while ethanol processed from alternative sources such as cellulose, switch grass or corn stover uses 9 – 15 gal water/gal ethanol. This level of water usage is still high compared to gasoline or diesel processed from petroleum sources (1 – 2.5 gal water/gal fuel), and future research needs to focus on technologies to reduce water use during the fuel processing stage. The level of reduction in water use will be essential if larger ethanol plants are built, and if the industry is to expand in any significant way outside of the Midwest.

6.5.2 Future work

Carbon dioxide emissions, and carbon balances in general, are going to be very important aspects in the bio-fuels industry. Energy and water usage also remain important parameters. The use of bio-refinery concepts and the coupling of other sources of CO_2 offer significant potential in the future. In addition, further investigation of water conservation, water reuse, zero-water-discharge designs and use of waste-heat within ethanol production facilities will also need to be further studied.

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7 Water Usage within Lignocellulosic Biomass and Cellulosic Biofuels Production

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In this chapter, the water requirements for biomass harvesting and cellulosic ethanol production via a fermentation pathway were assessed on a volume-to-volume basis (i.e., gallons of water consumption per gallon of ethanol produced) using data reported in the literature.[31] The water requirements were analyzed for a combination of three cellulosic feedstocks (i.e., hardwood, corn stover, and switch grass) and two pretreatment technologies (i.e., dilute acid and ammonia fiber expansion) under different water network configurations with an overall goal of zero wastewater discharge. The results indicate that the process water requirements are significantly dependent on the selection of pretreatment processes and feedstocks, while the effective cooling tower design and operation of a cooling tower offers an opportunity for saving utility water (i.e., cooling water and steam).

7.1 Introduction

The Energy Independence and Security Act (EISA) of 2007 calls for a fourfold increase in the production of biofuels such as ethanol in the U.S. by 2022 (EISA, 2007). This will require 36 billion gallons per year of total renewable fuels by 2022, including the production of 15 and 21 billion gallons of conventional (i.e., crop-based ethanol such as from corn) and advanced biofuels (i.e., 1 billion gallons of biodiesel, 16 billion gallons of cellulosic ethanol and 4 billion gallons from any other sources), respectively (EISA, 2007). Cellulosic ethanol is produced from wood, grasses, or nearly any inedible part of plant material. The U.S. consume approximately 134.51 billion gallons of gasoline and 13.2 billion gallons of fuel ethanol in the 2012 calendar year (U.S. EIA, 2014), of which approximately 1% is produced using cellulosic feedstock (U.S. Bioenergy Statistics, 2014).

There are currently ~211 starch-based ethanol plants in the U.S. with a total name plate capacity of 14875.4 MMgpy (RFA, 2014). Most of these ethanol plants use corn kernel as a feedstock along with other starch-based feedstocks. Other feedstocks such as corn stover, sorghum, sugarcane bagasse, beverage waste, wood waste and cheese whey are part of the small percentages of feedstocks used in future cellulosic plants (Wallace et al., 2005). Corn stover is the leaves and stalks of maize plants left after harvesting, and consists of stalk, leaves, and husk. The current estimated operating capacity of the biorefineries is 14,178.4 MMgpy (RFA, 2014). There are also many plants under construction or expansion for the production of corn and cellulosic ethanol with a potential capacity of 165 MMgpy (RFA, 2014). These plants are being scaled up from pilot to commercial scale.

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[31] The material in this chapter was originally published by the co-authors as Lingaraju et al. (2013) as part of work conducted for EPA under the Air, Climate and Energy Research Program.

Freshwater demand for energy production is a growing concern in the U.S. The increased use of biofuels is expected to offer benefits such as the decreased dependence on foreign oil, but may also present challenges such as the increased use of domestic agricultural resources, and negative impacts on air quality and surface and ground water resources (Alvarez et al., 2010). A National Research Council (NRC) report also indicates that the current estimates of consumptive water use by ethanol biorefineries are 4 and 9.5 gallons of water per gallon of ethanol produced from corn kernels and cellulosic feedstocks, respectively (Schnoor et al., 2008). Based on these estimates, an additional 256 billion gallons per year of freshwater will be required to meet the annual production of 36 billion gallons of ethanol by 2022. However, these estimates do not take the amount of water required for irrigation into consideration. As described in chapter 6, the cultivation of corn has an average irrigation water intensity of approximately 113 gallons-H_2O/gallon-ethanol and is highly variable, ranging from 15 to 934 gallons-H_2O/gallon-ethanol (King, 2008), depending upon regional differences in irrigation levels. The intensity of freshwater usage could be regionally problematic, representing an incremental withdrawal from already marginally sustainable or unsustainable sources. For example, current withdrawals in the High Plains Aquifer (more than 1.5 billion gallons per day) are greater than the aquifer's recharge rate, and the loss of this resource would be irreversible if the current withdrawal rate is not reduced (McMahon et al., 2007).

Cellulosic ethanol has received growing attention in recent years as it does not compete with food production, and instead uses agricultural by-products and energy crops which can grow even in arid regions (Dale, 2007; Chiu *et al.*, 2009; Zink, 2007; Keeney and Muller, 2006). It has been reported that the water consumption for irrigation significantly varies in terms of region (Wu et al., 2009) for crop cultivation. However, agricultural residues in the early 2000s comprised more than 70% of feedstock resources for cellulosic ethanol production, and the use of agricultural residues does not require any additional water consumption for irrigation (Perlack et al., 2005). The fraction of feedstock that is from agricultural residue is expected to decrease given that EISA calls for the production of 16 billion gallons of ethanol from cellulosic feedstock by 2022, and additional cellulosic material from biomass crops such as switch grass, short-rotation woody crops (SRWC) and other crops will be needed to meet additional future cellulosic ethanol demand. Switchgrass and SRWC are not considered to be agricultural residue, and thus could require significant amounts of water for irrigation. Tidwell et al. (2011) estimated that approximately 4,000 and 2,800 MGD of water will be required to grow switch grass and SRWC in 2030, respectively, to produce 80 billion gallons of cellulosic ethanol per year.[32] The authors estimated an average water intensity of 28 gal water/gal cellulosic ethanol produced for irrigation (Tidwell et al., 2011), approximately 25% of the average irrigation water intensity of corn cultivated for ethanol production.

In this study, a detailed water analysis for cellulosic ethanol production was focused only on process and utility water requirements, and the amount of water required for irrigation was not considered. Previous study results have been summarized in Table 7.1. There are very few studies available regarding the water quality and quantity requirements for cellulosic ethanol production, and various units of measurement have been used to estimate water requirements to meet respective objectives. In this study, the unit used is gallons of water per gallon of ethanol

[32] Note that this is more double the entire volume of renewable fuels called for in 2022 under RFS2 and five times the RFS2 volumes for cellulosic ethanol production in 2022. See Chapter 2 for further discussion of RFS2.

produced (gal water/gal ethanol). This unit of measure was selected so that the water requirement can be readily estimated by the production capacity. The primary purpose of this study is to assess the water quantity and quality requirements for cellulosic ethanol production in terms of a combination of different feedstocks, pretreatment technologies, and recycled water configurations.

Table 7.1 Literature review of water requirements for ethanol production

Water Requirement	Quantity	Units of Water Requirement	Feedstock	Reference
Freshwater make-up*	4.5 9	gal water / gal ethanol gal water / gal ethanol	Corn Kernel Cellulosic	(Schnoor et al., 2008) (Schnoor et al., 2008)
Freshwater make-up*	3.5-6	gal water / gal ethanol	Corn Kernel	(Keeney and Muller, 2006)
Freshwater make-up*	2.85	gal water / gal ethanol	Dried Distillers Grain	(Pfromm, 2008)
Freshwater make-up*	4.7	gal water / gal ethanol	Dried Distillers Grain	(Shapouri and Gallagher, 2005)
Freshwater make-up*	< 3	gal water / gal ethanol	Corn Kernel	(Swain, 2006)
Freshwater make-up*	6	gal water / gal ethanol	Corn Stover	(Montague, 2002; Aden, 2007)
Freshwater make-up*	1.5-4.3	gal water / gal ethanol	Switchgrass	(Laser et al., 2009b)
Freshwater	50	gal water / gal biofuel	Corn	(Hoekman, 2009)
Freshwater	3.4-4.6	gal water / gal ethanol	Gasoline	(Wu et al., 2009)

Note: * make-up is defined as net = inlet – outlet
1 gallon = 3.79 liters

7.2 Cellulosic Ethanol Process

A typical process configuration for cellulosic ethanol production is shown in Figure 7.1. Major unit operations include pretreatment, detoxification, fermentation, distillation, solid separation, drying, cooling, scrubbing, and wastewater treatment. In a typical dilute acid pretreatment process, dilute sulfuric acid with a concentration of 2% by weight/weight is mixed or contacted with biomass for cell wall rupture and to hydrolyze hemicellulose to other simple monomeric sugars at temperatures of 160 to 220°C for periods ranging from minutes to seconds. In the Ammonia Fiber Expansion (AFEX) pretreatment process, lignocellulosic biomass is exposed to a dosage of liquid ammonia (1 to 2 kg ammonia/kg dry biomass) at elevated temperature (132°C) and pressure (113 bar) followed by an instantaneous drop in pressure which causes ammonia vaporization and explosive decompression of the biomass resulting in fiber disruption (Mielenz and Mielenz, 2009). The biomass is transported by screw conveyors through a pre-steamer, a pretreatment tank, a blowdown tank, and an ammonia/acid pretreatment tank to form slurry. Solid-liquid separation is achieved by pressure filters.

A detoxification process is employed to remove enzyme inhibitors, sugar degradation products (e.g. furfural, 5-hydroxy methyl furfural) and chemicals that are toxic to microorganisms in the fermentation tank. The extraction of by-products and acids is achieved by non-dispersive membrane extraction and reactive membrane extraction; however, fouling caused by biomass particulate matter is reported (Ramaswamy et al., 2013). Over-liming by adjusting the pH to 10.0 by $Ca(OH)_2$ is an alternative detoxification process. The hydrolyzate from the detoxification tank is passed through saccharification and co-fermentation continuous stirred tank reactors containing enzymes for digesting C5 and C6 sugars to produce ethanol. A typical residence time is five days.

A two-step distillation process hosts a beer-separation column and a rectification column for repeated distillation to obtain pure ethanol. A typical beer column having 22 trays takes feed from fermenters to remove solids, lignin, insoluble proteins, and non-fermentable products as bottoms slurry from the overhead ethanol product. The rectification column, having 25 to 30 trays, concentrates the ethanol vapors to produce 95% weight fuel grade ethanol (Summers, 2006). The wastewater is collected, reclaimed, recycled, and pumped to the pretreatment reactor and condenser in the distillation unit. The process and utility water requirements for the unit operations are discussed in detail in Section 7.4.

Feedstock for cellulosic ethanol production can be classified into the following three categories: forest residues, agricultural crop residues and perennial crops (Perlack et al., 2005). In this report, three representative feedstocks (i.e., hardwood, corn stover and switch grass) and two representative pretreatment technologies (i.e., dilute acid and Ammonia Fiber Expansion [AFEX]) were selected based on the data available in the literature (Wooley et al, 1999; Montague, 2002; Laser et al., 2009a). Detailed descriptions of the two pretreatment technologies are given elsewhere (Mosier et al., 2005; Sun and Cheng, 2002).

7.3 Biomass Harvesting and Biofuel Conversion

The biomass harvesting process includes three operations: harvesting of biomass, raking the crop residues into windrows, and baling of the windrows into square or cylindrical shapes for storage. Specialized equipment (i.e., combine) is used for the single-pass, two-pass, or three-pass method for biomass harvesting. In the single-pass method, the three operations are collectively performed by a single piece of equipment. In the two-pass method, harvesting and windrowing is performed by separate equipment. The three-pass method utilizes different equipment for each of the three operations (Ertl, 2013). The high moisture content of corn stover obtained after the single pass harvesting method is reported to be ~46% (Shinners et al., 2009).

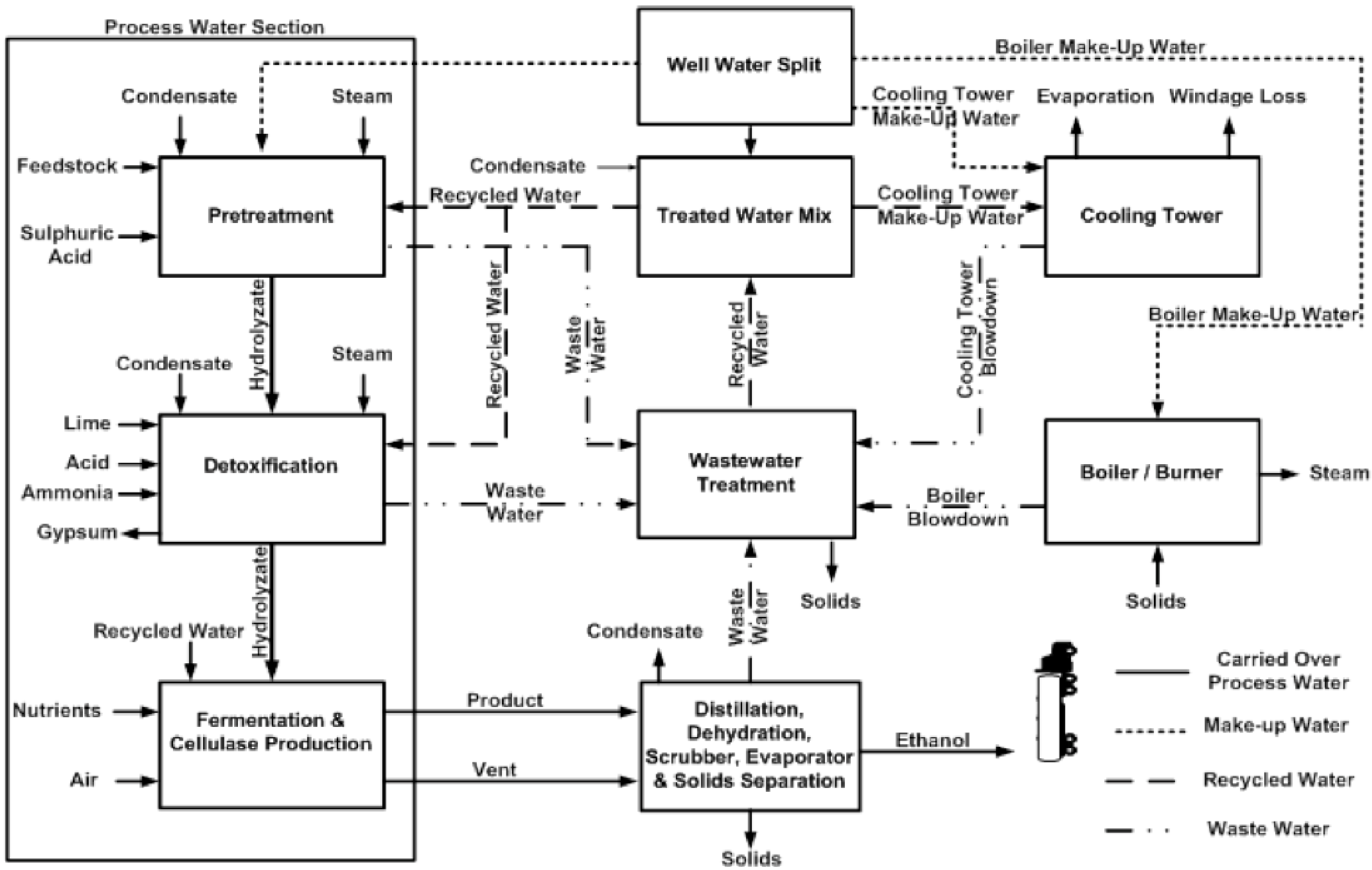


Figure 7.1 Process schematic for cellulosic ethanol production

A dry or wet storage method is used to preserve the harvested biomass. Dry storage involves field drying of the harvested biomass where the moisture content of freshly harvested biomass is reduced to a desired level (e.g., ≤20%). The field drying process takes from several days to weeks depending on ambient temperatures and rainfall during the harvest season. Wet storage methods are proposed in regions where the humidity and rainfall precipitation does not favor drying conditions. In the wet storage method, the freshly harvested non-dried biomass containing >45% moisture content is stored in horizontal silos, airtight pits, or plastic wraps. The wet storage method can be integrated with chemical or biological pretreatment methods because of the growth of fermentative microorganisms under anaerobic conditions (Li *et al*., 2011). Two schematic block diagrams of the biomass harvesting process and the equipment used are shown in Figures 7.2 and 7.3, respectively.

Pretreatment methods break down the lignin linings of the cell membrane in order to facilitate easy access of cellulose to enzymes. Steam injection into the biomass cells in the presence of ammonia or dilute acid leads to cell wall rupture. The biomass is washed with freshwater and carried over to the fermentation chamber. The pretreatment methods used to cause cell wall rupture are classified as 1) physical, 2) physicochemical and chemical, and 3) biological pretreatment methods. Physical treatment includes milling, high pressure steaming, and irradiation. Chemical and physiochemical methods include the use of explosion, gas, acid, alkali, oxidizing agents, cellulose solvents, and lignin solvent extraction. Biological pretreatment methods include the use of microorganisms such as fungi for causing cell wall rupture. Among the aforementioned methods, physicochemical and chemical methods are efficient because of delignification, complete hemicellulose hydrolysis and breakdown of cellulose. The ammonia fiber expansion method (AFEX) takes physicochemical actions on the plant cells recovering 93% of hemicellulose, and dilute acid treatment has chemical actions recovering 90% hemicellulose. However, ammonia solvent evaporation and pH neutralization before enzymatic hydrolysis are the major challenges faced when using chemical methods (Karimi, 2007). Depending upon a combination of feedstocks used and the pretreatment type (AFEX or dilute acid), the quantity of water required for the entire process varies (Zink, 2007).

In the saccharification process, cellulose and hemicellulose are converted into simple C5 and C6 sugars by enzymatic activities. The freshwater containing bacterial broth is left for several hours for the fermentation process to take place where the simple monomeric sugars are converted into ethanol. The primary enzymes (cellulose and hemicellulase) and accessory enzymes (endoglucanase, exoglucanase, glucocidase and glucosyl hydrolase) produced from microbial activities of *Saccharomyces cerevisiae, Clostridium thermocellum, Trichoderma reesei, Escherichia coli, Zymomonas mobilis, Pachysolen tannophilus, C. shehatae, Pichia stipitis, Candida brassicae* and *Mucor indicus* aid in the saccharification process (Sarkar et al., 2012).

After the conversion of sugars into ethanol, pure ethanol is separated from an ethanol-water mixture by distillation. The current distillation process produces 95% weight ethanol containing 5% water and by-products as impurities (Summers, 2006). However, pervaporation using hydrophilic membranes for biofuel dehydration or organophilic membranes for biofuel enrichment produces 99.9% (weight) fuel grade ethanol (Wang and Chung, 2012). Steam is required for preheating the ethanol-water mixture. The reboiler and condenser require steam and cooling water, respectively, to recover products from the preheated mixture.

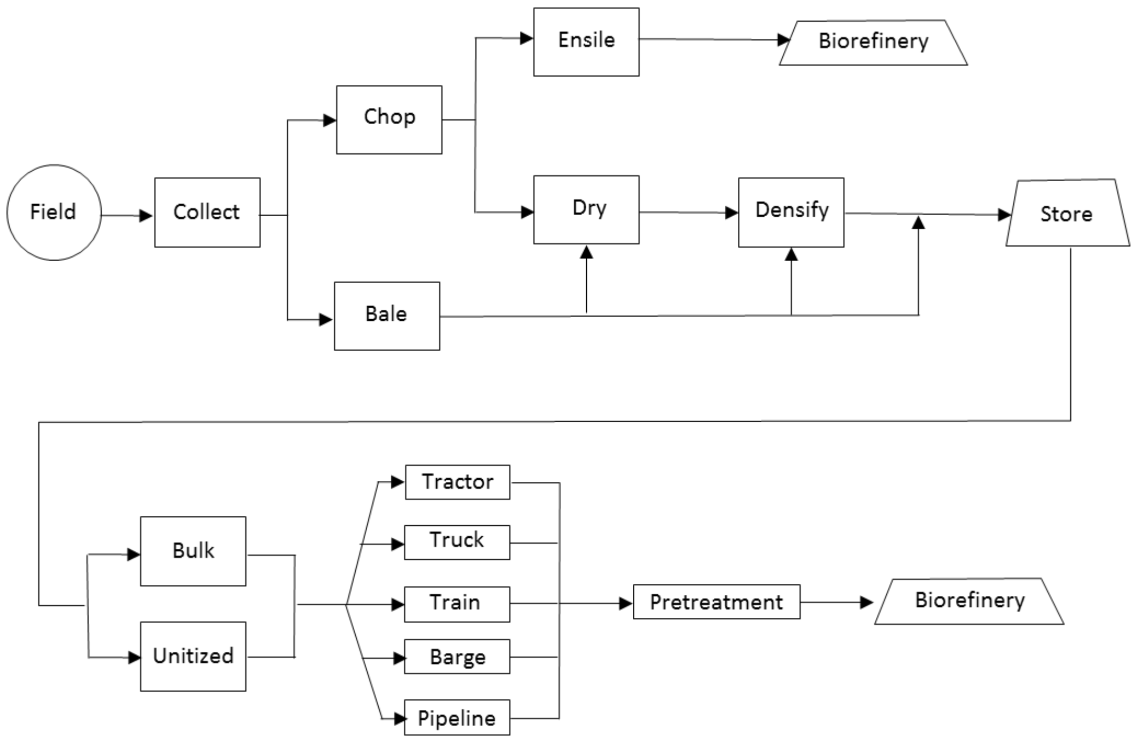


Figure 7.2 Unit operations involved in a biomass supply chain from field to biorefinery.

Figure 7.3 Equipment used in the biomass harvesting process.

7.4 Water Usage and Wastewater Generation

One of the constraints associated with cellulosic ethanol production is the water requirement for the cultivation of energy crops. A major proportion of water usage for the production is to irrigate lignocellulosic biomass. It was estimated that in 2006, 5,616 million gallons per day (MGD) was used for irrigating crops that were used to produce biofuel (primarily from corn). The amount of water required for conversion to biofuels was relatively lower at 94 MGD. It is predicted that the amount of irrigation water for feedstocks in the year 2030 would increase to 11,458 MGD (4649, 4077 and 2822 MGD for corn, switch grass and SRWC, respectively), while that for conversion would require 470 MGD (219 and 251 MGD for corn and cellulosic ethanol, respectively; Tidwell et al., 2011). Water wastage as run-off during the cultivation of plants is a significant issue. Irrigation water loss occurs due to run-off and evaporation from the land.

Water is required to wash off soil contaminants and other impurities from the biomass matter after harvest. Water usage is represented by the amount of water consumed to compensate for the loss of total moisture content of the plant mass due to evaporation, evapotranspiration (combination of transpiration and evaporation of water from leaves), and wind loss. Evapotranspiration water usage of different bioethanol crops in the U.S. is estimated to be 500 to 4,000 gallons of water per gallon of ethanol produced (Dominguez-Faus et al., 2009). It was also reported to take ~2,500 gal water/gal biofuel, which includes 820 gal of irrigation water (UNESCO, 2014). The moisture content (in percentage units) levels of the freshly harvested and field-dried biomass (shown in Table 7.2a) should be regulated to avoid spoilage, mold formation and for optimizing bioethanol yield.

The irrigation water supply and the water loss conditions (evapotranspiration and wind loss) determine the total plant moisture content during harvest. The total biomass moisture content includes intrinsic and extrinsic moisture content. Intrinsic moisture content is the amount of biomass moisture measured without the influence of the ambient weather conditions. Extrinsic moisture content is the amount of moisture measured after exposing the biomass to the prevailing weather conditions of the harvest season. Higher moisture content (>60%) in the plant residues depletes the net calorific value of cellulosic bioethanol produced in addition to potential drawbacks such as biomass spoilage, mold formation in the stored bales, and dry matter loss. To avoid this, the storage bales should be kept at moisture content of less than or equal to 20% (Ertl, 2013).

Field drying is an economical method to reduce the extrinsic moisture content of feedstock. Moisture content is lost or gained depending upon the storage conditions. Freshly harvested corn stover contains ~47-66% moisture. After the baling process, the reduced moisture content is ~16% (Petrolia, 2008). Air-drying of the hardwood by exposing the stacked wood boards to the blowing winds reduces the moisture content to 17% (Roise et al., 2013). Freshly harvested switch grass contains 43% moisture content and the moisture level reduces to 10% after a week depending upon the weather conditions. In Wisconsin, post-harvest field drying reduces the moisture level of switch grass from between 46 and 66% down to 20% (Sokhansanj et al., 2009).

Table 7.2a Literature review of moisture content during the biomass harvesting process

Feedstock	Source	Quantity	References
Corn stover	Moisture content	47-66 %	(Somerville et al., 2010)
Corn stover	Moisture content	30 %	(Wu *et al.*, 2014)
Freshly harvested Switch grass	Moisture content	43 %	(Sokhansanj et al., 2009)
Switch grass after 3-7 days of harvest	Moisture content	10-17 %	(Sokhansanj et al., 2009)

Table 7.2b Literature review of water consumption for different feedstocks

Feedstock	Source	Quantity	References
Hard wood	Freshwater	2.4 gal of water consumed / gal of biofuel	(Somerville et al., 2010)
Switch grass	Freshwater	1.9-9.8 gal of water consumed / gal of biofuel	
Corn	Freshwater	2.8-40 gal of water consumed / gal of biofuel	(Tidwell et al., 2011)

The conversion of cellulosic biomass to biofuel requires freshwater. The biofuel conversion process consists of the pretreatment of candidate feedstocks, fermentation, and biofuel recovery. Water requirements are compared for a combination of different feedstocks and pretreatment technologies as summarized in Table 7.3. The water used within the process was classified into the following three categories: freshwater, recycled water, or carried-over water. Freshwater is make-up water from an external source such as a river, reservoir, or well. Recycled water refers to either reclaimed or non-treated process water. Reclaimed water is the water after wastewater treatment subject to aerobic and anaerobic treatment while non-treated water refers to a direct evaporator condensate captured from the cooling process, which does not require further treatment. Carried-over water is the process water carried over to the next unit operation, such as hydrolyzate from a pretreatment reactor, the broth sent to a fermentation reactor, or the ethanol-water mixture sent to the distillation column.

All of the four cases in Table 7.3 share a common process configuration with minor variations in the distribution of fresh and recycled water among various unit operations. Table 7.3 summarizes the differences in process configurations and utilization of recycled water. A zero wastewater discharge design concept was applied to all cases. The variations in different water networks for these process configurations is discussed in more detail in section 7.4.1

Table 7.3 Four cases analyzed for water quality and quantity requirements

Plant Aspect	Case 1 (Wu *et al.*, 2009)	Case 2 (Montague, 2002)	Case 3 (Laser *et al.*, 2009a)	Case 4 (Laser *et al.*, 2009a)
Feedstock	Hardwood	Corn Stover	Switchgrass	Switchgrass
Dry tonne/day	2,000	2,000	4,535	4,535
Washing	Yes	No	Yes	No
Pretreatment	Dilute Acid	Dilute Acid	Dilute Acid	AFEX
Biological Conversion	Simultaneous Saccharification and Co-Fermentation (SSCF)	Separate Saccharification and Co-Fermentation	Simultaneous Saccharification and Co-Fermentation (SSCF)	Consolidated Bioprocessing
Distillation Column Bottoms	Evaporative concentration of distillation column bottom liquids	Evaporative concentration of distillation column bottom liquids	Evaporative concentration of distillation column bottom liquids	Distillation column bottom liquid is sent to waste treatment
Use of condensate from evaporator	Condensate is used as recycled water for pretreatment without further dilution	Condensate is used as recycled water after dilution with make-up water	Condensate is used as recycled water for pretreatment without further dilution	Condensate is eliminated
Residue Processing	Residue is burned to produce steam & power in Rankine Cycle	Residue is burned to produce steam & power in Rankine Cycle	Residue is burned to produce steam & power in Rankine Cycle	Residue processed to produce fuel, power and animal feed
Chilled Water	N/A	N/A	N/A	Chilled water is added for ammonia recovery

7.4.1 Water quantity

A water quantity requirement analysis was based on an overall water balance for the entire process, as well as for a water balance for each unit operation. Water input into the entire ethanol plant shown in Figure 7.4 consists of 1) moisture in feedstock, 2) moisture in the air, chemicals and nutrients, and 3) make-up water. The overall water output from the entire ethanol plant consists of water losses including: 1) windage and evaporation loss, 2) venting to the atmosphere, 3) moisture included in solid waste, and 4) other handling losses. A typical cellulosic ethanol production process has the following unit operations on the process side: pretreatment, fermentation, and product recovery. The utility side of the cellulosic ethanol plant consists of a cooling tower, residue processing, steam generation, and wastewater treatment. A water consumption rate was obtained by dividing a volumetric water flow rate in gallons per hour by an ethanol production rate in gallons per hour. The accuracy of the data is the same as that of the source data used from the references. The purpose and water consumption of each unit operation are given below.

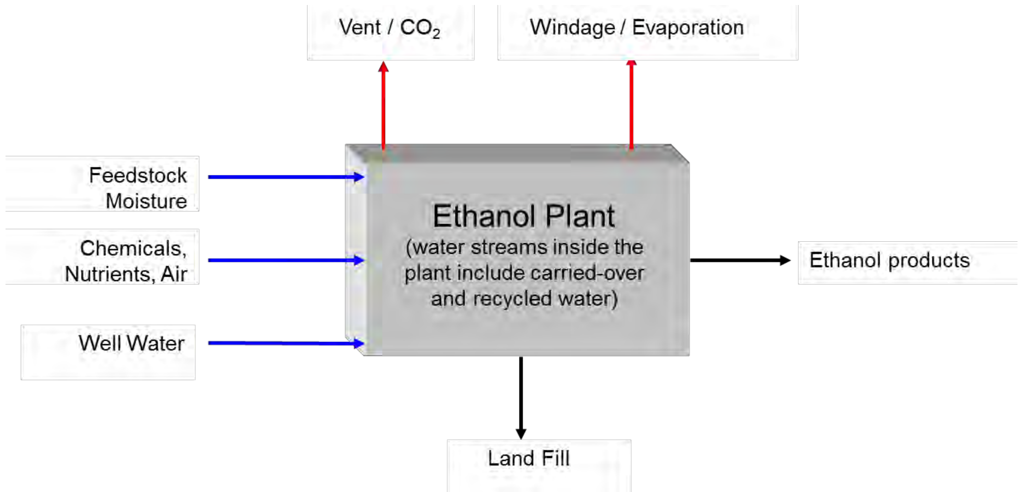


Figure 7.4 Overall water balance of cellulosic ethanol plant.

Pretreatment: Pretreatment physicochemically changes the structure of cellulosic biomass to make the enzymes easily accessible to the cellulose and hemicellulose fractions for the conversion into fermentable C5 and C6 monomeric sugars during subsequent fermentation. Major water requirements of this section consist of steam injection into the pretreatment reactor as process water and dilution water for slurry and hydrolyzate carried over to the fermentation unit in order to maintain a required solid-to-liquid ratio in the saccharification and fermentation tank.

Saccharification and Fermentation: In this unit operation, the cellulose and hemicellulose fractions are converted into sugars by the action of cellulase followed by fermentation by microorganisms. Water is required for the activity of microorganisms in the broth.

Product Recovery: The product recovery section consists primarily of distillation columns where the ethanol and water mixture is separated for ethanol production. The product recovery section also receives the ethanol-water mixture from fermentation. Water is required to preheat the feed to the distillation column and its reboiler.

Cooling Tower: Cooling water is required throughout the process as utility water. In the National Renewable Energy Laboratory (NREL) process (Wallace *et al*., 2005), the following process steps require cooling water: 1) cooling of pretreated hydrolyzate, 2) cooling of the flash vent from the pretreatment unit and pneumapress air vent before being sent to wastewater treatment, 3) temperature control for fermentation at 41°C, 4) cooling of rectification column reflux, 5) cooling of the wastewater streams before entering anaerobic digestion, and 6) cooling of the evaporator liquid into condensate for recycling water. Heated water is then cooled down by free or forced convection with make-up water acting as a heat sink. In this process, a significant amount of water is evaporated from the cooling tower and is considered evaporation and windage loss. A typical cooling tower operation can consume 75% of the water sent to the cooling tower by evaporation, and recycle the remaining 25% as blowdown (Owens, 2007; Wurtz, 2008). The make-up water requirement primarily results from this loss.

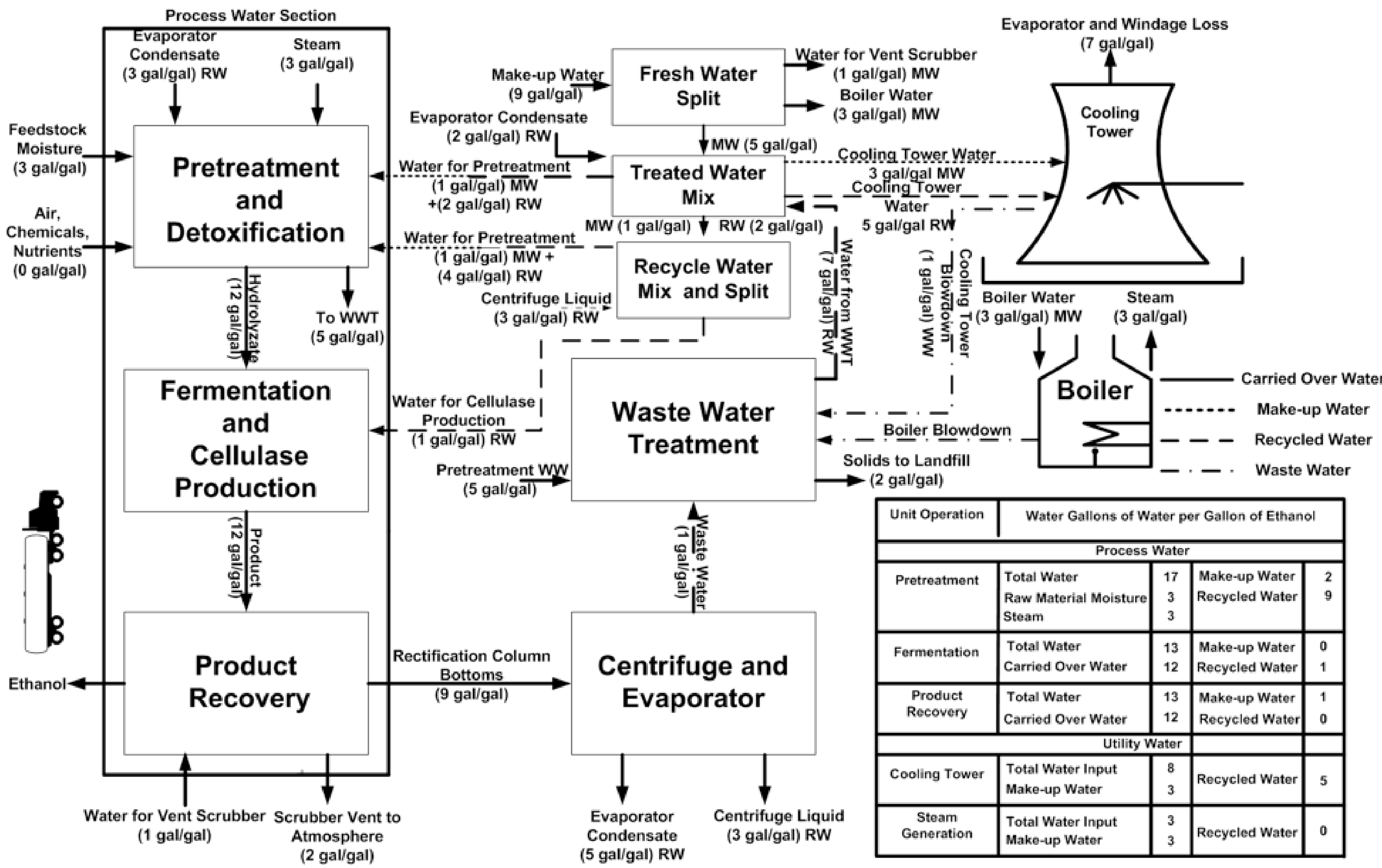
Steam Generation: Steam is required in the pretreatment section as process water and in the product recovery section as utility water for the preheater and reboiler of the distillation column. Freshwater is subjected to boiler feed water treatment before steam generation inside the boiler, which requires the highest quality water.

Four cases of cellulose ethanol production were analyzed for water consumption. In the overall water balance shown in Table 7.4, freshwater make-up is the single-most important water input into the system. Other minor water flow components include feedstock moisture and moisture in chemicals and nutrients (i.e., 0−0.2 gal water/gal ethanol). Freshwater make-up ranges from 9 to 15 gal water/gal ethanol. Relatively, cases 2, 3 and 4 require a greater amount of freshwater than case 1 because of a smaller quantity of water recycled in their process configurations as shown in Figures 7.5 through 7.8. The detailed results for individual unit operations are given below.

Table 7.4 Overall water balance*

	Case 1 **(Dilute acid + Hardwood)**	**Case 2** **(Dilute acid + Corn Stover)**	**Case 3** **(Dilute acid + Switchgrass)**	**Case 4** **(AFEX + Switchgrass)**
Inlet (gallons of water per gallon of ethanol)				
Feedstock Moisture	3	1	2	1
Air, Chemicals, Nutrients	0	0	Negligible	Negligible
Make-up water	9	12	15	12
Inlet Total	**12**	**13**	**17**	**13**
Outlet (gallons of water per gallon of ethanol)				
Evaporation & windage Loss	7	7	7	10
Vent to Atmosphere	2	2	3	2
Moisture in Residues for Landfill	2	3	5	1
Handling Loss	1	1	2	0
Outlet Total	**12**	**13**	**17**	**13**

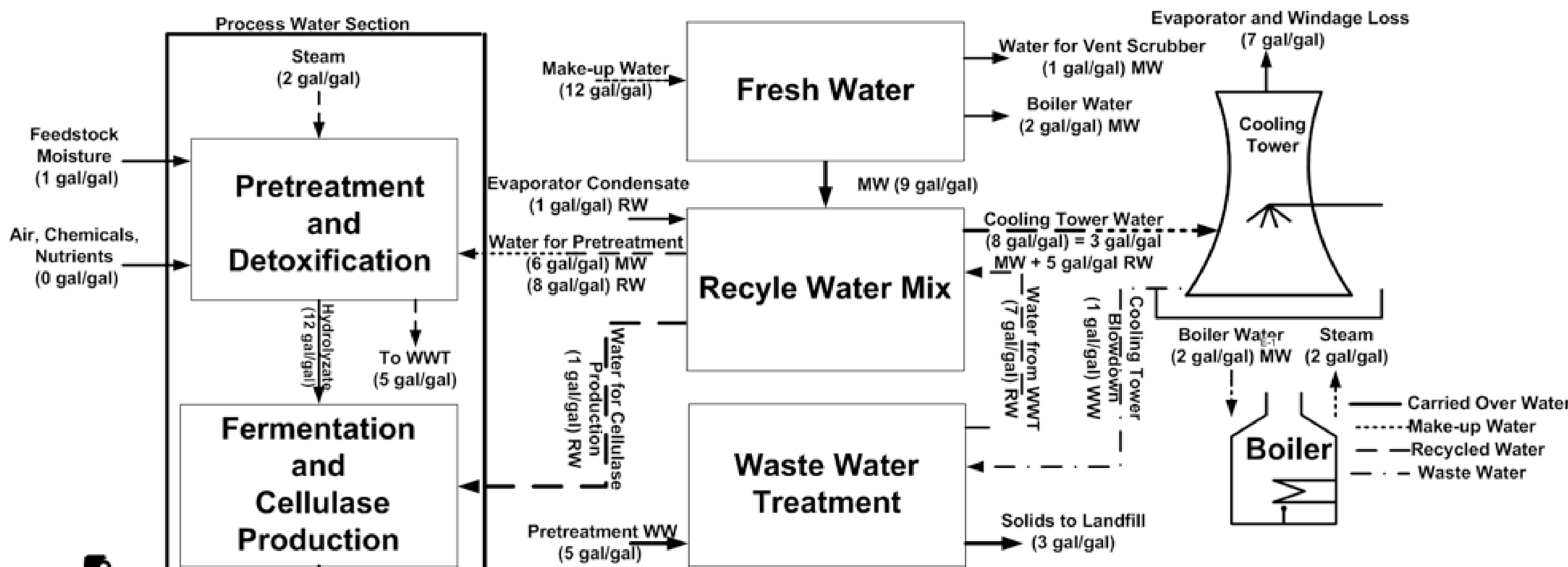
Note: * This water balance does not include carried-over and recycled water used inside the process.



Unit Operation	Water Gallons of Water per Gallon of Ethanol			
	Process Water			
Pretreatment	Total Water Raw Material Moisture Steam	17 3 3	Make-up Water Recycled Water	2 9
Fermentation	Total Water Carried Over Water	13 12	Make-up Water Recycled Water	0 1
Product Recovery	Total Water Carried Over Water	13 12	Make-up Water Recycled Water	1 0
	Utility Water			
Cooling Tower	Total Water Input Make-up Water	8 3	Recycled Water	5
Steam Generation	Total Water Input Make-up Water	3 3	Recycled Water	0

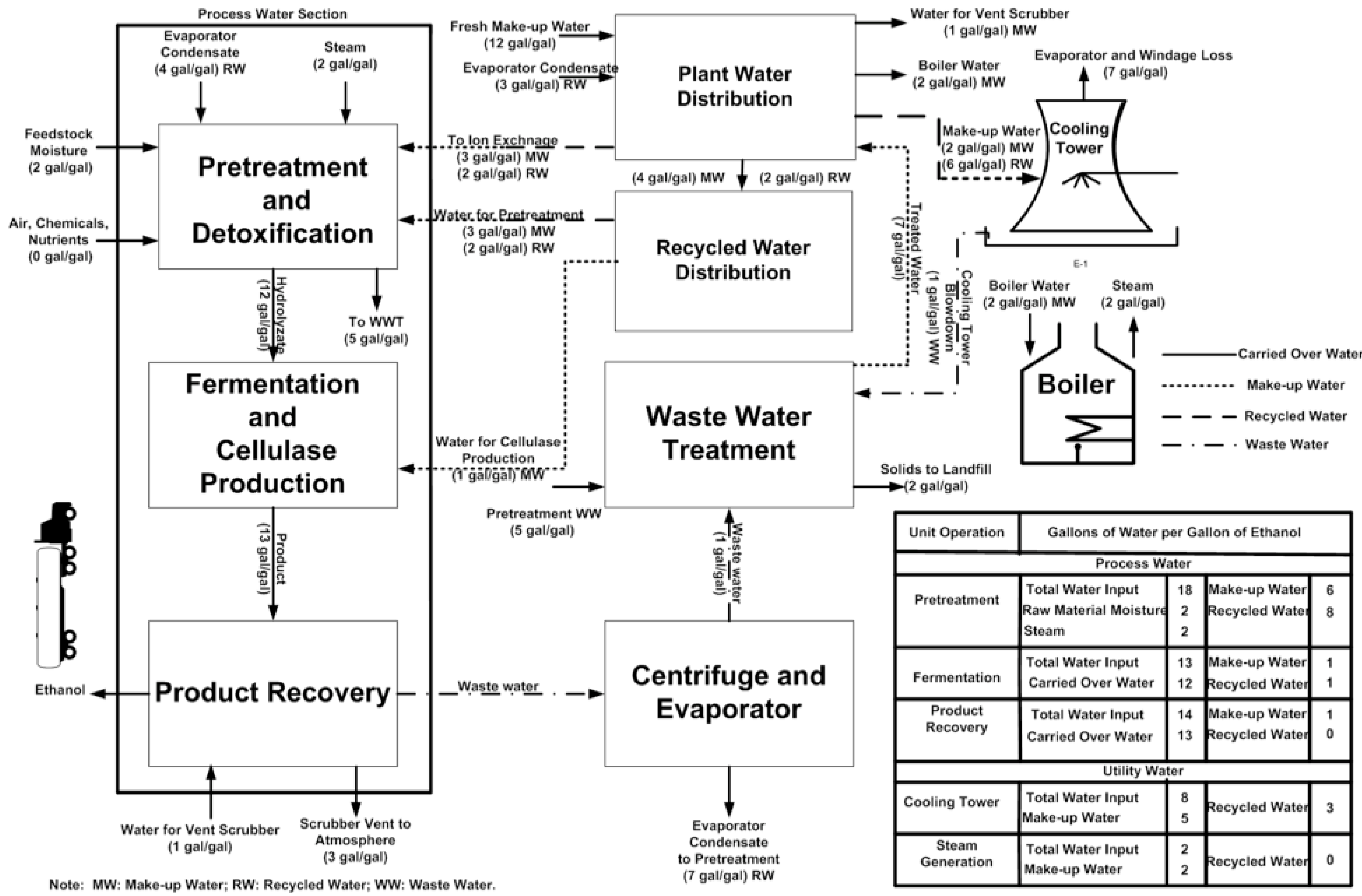
Note: MW: Make-up Water; RW: Recycled Water; WW: Waste Water.

Figure 7.5 Process layout based on case 1 (hardwood + dilute acid pretreatment).



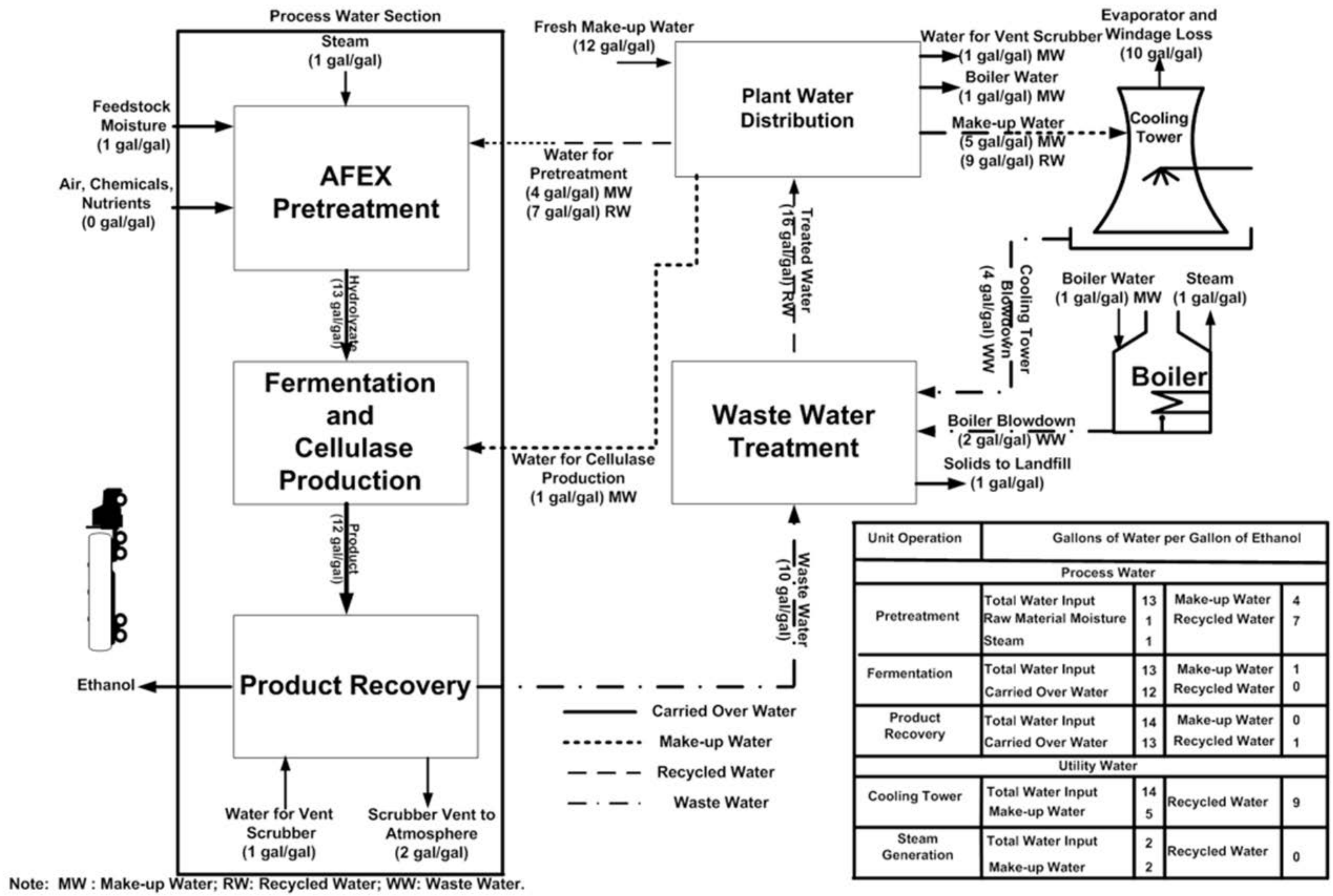
Unit Operation	Gallons of Water per Gallon of Ethanol			
	Process Water			
Pretreatment	Total Water Input Raw Material Moisture Steam	17 1 2	Make-up Water Recycled Water	6 8
Fermentation	Total Water Input Carried Over Water	13 12	Make-up Water Recycled Water	0 1
Product Recovery	Total Water Input Carried Over Water	13 12	Make-up Water Recycled Water	1 0
	Utility Water			
Cooling Tower	Total Water Make-up Water	8 3	Recycled Water	5
Steam Generation	Total Water Make-up Water	3 0	Recycled Water	0

Figure 7.6 Process layout based on case 2 (corn stover + dilute acid pretreatment).



Unit Operation	Gallons of Water per Gallon of Ethanol			
Process Water				
Pretreatment	Total Water Input Raw Material Moisture Steam	18 2 2	Make-up Water Recycled Water	6 8
Fermentation	Total Water Input Carried Over Water	13 12	Make-up Water Recycled Water	1 1
Product Recovery	Total Water Input Carried Over Water	14 13	Make-up Water Recycled Water	1 0
Utility Water				
Cooling Tower	Total Water Input Make-up Water	8 5	Recycled Water	3
Steam Generation	Total Water Input Make-up Water	2 2	Recycled Water	0

Figure 7.7 Process layout based on case 3 (switch grass + dilute acid pretreatment).



Unit Operation	Gallons of Water per Gallon of Ethanol			
Process Water				
Pretreatment	Total Water Input	13	Make-up Water	4
	Raw Material Moisture	1	Recycled Water	7
	Steam	1		
Fermentation	Total Water Input	13	Make-up Water	1
	Carried Over Water	12	Recycled Water	0
Product Recovery	Total Water Input	14	Make-up Water	0
	Carried Over Water	13	Recycled Water	1
Utility Water				
Cooling Tower	Total Water Input	14	Recycled Water	9
	Make-up Water	5		
Steam Generation	Total Water Input	2	Recycled Water	0
	Make-up Water	2		

Figure 7.8 Process layout based on case 4 (switch grass + afex pretreatment).

Table 7.5 Water balance in individual unit operations

		Case 1 (Dilute acid + Hardwood)		**Case 2 (Dilute acid + Corn stover)**		**Case 3 (Dilute acid + Switchgrass)**		**Case 4 (AFEX + Switchgrass)**	
Biomass capacity (Dry tonnes per hr)		83		83		189		189	
Ethanol capacity (Gallons of ethanol/hr)		6,181		8,219		7,018		21,888	
Process Water (gallons of water per gallon of ethanol)									
		Input	Output	Input	Output	Input	Output	Input	Output
Pretreatment	Total water	17	17	17	17	18	18	13	13
	Raw materials	3 (18%)		1 (6%)		2 (12%)		1 (8%)	
	Reclaimed water	9 (53%)		9 (53 %)		8 (47%)		7 (54%)	
	Make-up water	2 (12%)		5 (29 %)		6 (29%)		4 (30%)	
	Process steam**	3 (18%)		2 (12%)		2 (12%)		1 (8%)	
Fermentation	Total water	13	13	13	13	13	13	13	13
	Carried over water	12 (92%)		12 (92%)		12 (92%)		12 (92%)	
	Reclaimed water	1 (8%)		1 (8%)		1 (8%)		0 (0%)	
	Make-up water	0 (0%)		0 (0%)		1 (0%)		1 (8%)	
Product Recovery	Total water	13	13	13	13	14	14	14	14
	Carried over water	12 (92%)		12 (92%)		13 (93%)		13 (93%)	
	Reclaimed water	0 (0%)		0 (0%)		0 (0%)		1 (7%)	
	Make-up water	1 (8%)		1 (8%)		1 (7%)		0 (0%)	
Utility Water (gallons of water per gallon of ethanol)									
Cooling Tower	Total water	8	1	8	1	8	1	14	4
	Reclaimed water	5 (65%)		5 (60%)		3 (35%)		9 (64%)	
	Make-up water	3 (35%)		3 (40%)		5 (65%)		5 (36%)	
Steam Generation	Total water	3	3	3	3	2	2	2	2
	Reclaimed water	0 (0%)		0 (0%)		0 (0%)		0 (0%)	
	Make-up water*	3 (100%)		3 (100%)		2 (100%)		2 (100%)	

Note: Make-up water for steam generation* is used for process steam directly injected into the pretreatment reactor** and utility steam for the preheater and reboiler used for distillation. The utility steam used for distillation is not shown because its consumption is relatively small.

Pretreatment and Detoxification: In the water requirement estimation, the dilute acid pretreatment used for cases 1, 2 and 3 requires 17 to 18 gal water/gal ethanol irrespective of the feedstock, while the AFEX pretreatment used for case 4 consumes 13 gal water/gal ethanol. The process steam is directly injected into the pretreatment reactor, accounting for 2 to 3 gal water/gal ethanol for cases 1, 2 and 3, and 1 gal water/gal ethanol for case 4. Dilute acid pretreatment for switchgrass consumes the largest amount of water. On the other hand, a combination of switchgrass and AFEX pretreatment in case 4 requires the lowest water consumption of 13 gal water/gal ethanol due to a very high ethanol yield—almost three times as much ethanol than case 3 (Laser et al., 2009a).

Furthermore, operating conditions are different among the four cases. The typical operating temperature and pressure of the dilute acid pretreatment are 12.1 atm and 190 °C, while AFEX pretreatment is typically operated at 21 atm and 90 °C (Laser *et al*., 2009a). Although there is a stringent water quality requirement for slurry dilution in the pretreatment reactor, the recycle water generated from the wastewater treatment unit meets the requirements to be used as make-up water for slurry dilution (Merrick & Company, 1998). In Case 2, for example, the condensate from the evaporator was directly used as process water without wastewater treatment as shown in Figure 7.4. The AFEX pretreatment used for Case 4 turned out to consume the least amount of water for pretreatment. For cases 1 through 3, the output water from the pretreatment section is estimated to be ~17 to 18 gal water/gal ethanol, and 12 gal water/gal ethanol was carried over to fermentation. The difference between pretreatment and fermentation, ~5 to 6 gal water/gal ethanol, is directed to wastewater treatment.

Fermentation: Water consumption in fermentation is minimum as the hydrolyzate carried over from the pretreatment and detoxification units is already diluted water. Approximately 1 gal water/gal ethanol is added to the process for the growth of micro-organisms.

Product Recovery: Fermented beer is distilled to separate ethanol from water in product recovery operations. Cooling water is recirculated in the condenser of a distillation column without any make-up water. A vent scrubber used to separate CO_2 consumes ~1 gal water/gal ethanol. Wastes are recovered from the distillation column bottom in order to fully utilize the energy required to generate steam for this section (Merrick & Company, 1998). The waste heat is used in evaporators and the distillation reboiler for saving energy. This arrangement also helps reduce the load on the wastewater treatment unit by concentrating the streams. The steam requirement as utility water for the reboiler and preheater of the distillation feed stream is less than 0.5 gal water/gal ethanol for all cases. This utility steam consumption is smaller than the process steam consumption for the pretreatment section in all cases.

Wastewater Treatment: The aerobic and anaerobic wastewater treatment unit originally designed by Merrick and Company (Hill et al., 2006) was used in all four cases. High chemical oxygen demand (COD) streams were sent to the wastewater treatment unit, and a 95% decrease in the COD value was assumed to be achieved in the reclaimed water streams. The input streams of the wastewater treatment unit come from all unit operations, including 1) Pretreatment: waste from flash vents and an ion-exchange unit, and 2) Product recovery: part of the evaporator condensate is reclaimed in the wastewater treatment unit and is routed back to the process. Some of the waste streams from distillation columns are sent to evaporators and centrifuges located after the distillation columns in series. The recycled water collected from centrifugation is also re-used in the process without any wastewater treatment where water quality requirements are not stringent (Montague, 2002). Such streams help reduce the load on the wastewater treatment.

7.4.2 Water quality

Soluble solids, insoluble solids and chemical oxygen demand (COD) are the primary indicators of water quality affecting the cellulosic ethanol production process. In this study, their concentrations were calculated for the streams sent to wastewater treatment, reclaimed water and recycled water without treatment. Then the COD of each stream was calculated by multiplying the mass flow rate of each component by a COD factor reported in a previous NREL study (Merrick & Company, 1998)

Reclaimed water: Recycled water is a supplement to make-up water. High-strength wastewater treatment processes consist of aerobic oxidation followed by anaerobic digestion with a typical 95% COD reduction rate. A wastewater treatment feasibility study (Merrick & Company, 1998) recommends on-site wastewater treatment instead of discharge to the publicly owned treatment works (POTW) for cellulosic ethanol production. Consistent with this recommendation, all of the cellulosic ethanol plants analyzed here were assumed to use on-site wastewater treatment. The effluent from on-site wastewater treatment is recycled in the ethanol production process, and this water stream is labeled as recycled water in the analysis. Distillation columns are followed by centrifuges and evaporators to concentrate the waste streams from product recovery, and the water separated from centrifuges and evaporators is recycled to the distillation columns. The centrifuges and evaporators are used to remove insoluble solids and to recycle water through a three-stage evaporation process (Merrick & Company, 1998). The evaporator condensate is referred to as non-treated recycle water. In a recent NREL process design (Montague, 2002), the size of the wastewater treatment unit was reduced by routing the water, containing a high level of suspended solids (SS), into the centrifuge-evaporator system. Water containing a high level of dissolved solids (DS) typically has a high COD content, and is routed to the wastewater treatment unit instead of the evaporator system (Wooley et al., 1999). In this analysis, different water networks were applied to individual cases following the network configurations used in the references (Wooley et al., 1999; Montague, 2002; Laser et a*l*., 2009a).

The quality of water streams used within a cellulosic ethanol plant is summarized in Table 7.6. The COD level of the influent wastewater streams is in the range of 15,000 to 50,000 mg COD/L. After wastewater treatment with a reduction of 95% or higher, the COD level decreases to the range of 750 to 2,500 mg COD/L. A reduction in the COD level for different cases depends on the performance of aerobic and anaerobic processes used in wastewater treatment, and the applied COD removal efficiencies used for the four analyzed cases are summarized in Table 7.6.

Cooling Tower: The primary water consumption in the cellulosic ethanol production process stems from windage and evaporation loss. The water loss from the cooling tower takes ~75 to 80% of the make-up water supplied to the cooling tower. The windage and evaporation loss for case 4 is largest because 14 gal water/gal ethanol are sent to the cooling tower, whereas for cases 1, 2, and 3, only 8 gal water/gal ethanol are sent to the cooling tower. The higher cooling water requirement for case 4 results from the use of chilled water for ammonia recovery. The loss can be avoided with the promotion of advanced cooling technologies, and some of the water saving options and alternatives under consideration and development are summarized in Table 7.6. From a water requirement analysis of the current cellulosic ethanol plant designs and a literature survey of water requirements for thermoelectric power plants, it is understood that a major share of make-up water withdrawal is used as cooling water. Hence, the development of advanced cooling technologies that can reduce cooling water consumption and utilize unconventional water resources will be critical to reducing water requirements for energy production (Rodgers and Castle, 2008; Feeley and Carney, 2005; Manan et al., 2004).

Table 7.6 Water quality used for four cases

	Case 1 (Dilute acid + Hardwood)	Case 2 (Dilute acid + Corn stover)	Case 3 (Dilute acid + Switchgrass)	Case 4 (AFEX + Switchgrass)
Biomass capacity (Dry tonne/hr)	83	83	189	189
Ethanol capacity (Gallons of ethanol/hr)	6,181	8,219	7,018	21,888
Quality of Influent Wastewater to Wastewater Treatment				
Total input mass flow rate (kg/hr)*	179,283	97,265	187,603	1,323,100
COD (mg COD/L)*	29,164	14,575	49,283	22,333
COD (kg/hr)*	5,511	1,446	4,833	29,917
% Soluble Solids	< 0.1	< 0.1	<0.1	<0.1
% Insoluble Solids	< 0.1	< 0.1	< 1.5	<1.5
Quality of Effluent Wastewater from Wastewater Treatment				
Total output mass flow rate (kg/hr)*	173,154	95,805	181,822	1,225,845
Aerobic & anaerobic removal efficiencies (%)	92	90	96	97
COD (mg COD/L)*	2,237	1,315	1,747	746
COD (kg/hr)*	388	126	318	920
% Soluble Solids	< 0.1	< 0.1	< 0.1	< 0.1
% Insoluble Solids	< 0.1	< 0.1	< 0.1	< 1.5

Notes: N/A - Not Available;
* - Calculation based on the values reported in the references (See Table 7.3 for references).

Steam Generation: Steam is required for direct injection into the pretreatment reactor as process water and for the preheater and reboiler in the product recovery section as utility water. The steam requirement for the preheater and reboiler in the distillation column is less than 0.5 gal water/gal ethanol production, and is much less than that for the pretreatment section as shown in Table 7.4. The water quality requirement for steam generation is very stringent. The scale build-up, frequency of boiler blowdown, and use of boiler chemicals can be minimized by reducing such impurities as colloids, silicates, zinc, and alumina (Wooley et al., 1999). Allowable total suspended solids in the boiler feed water are less than 1% for all four cases (Wooley et al., 1999; Montague, 2002). Because of these stringent water quality requirements, the wastewater treatment effluents shown in Table 7.6 are unlikely suited for stream generation. Large potential exists in 1) recycling and reusing most of the wastewater, and 2) avoiding the windage and evaporation water loss that can significantly reduce make-up water.

7.5 Technological Challenges and Opportunities for Water Reuse and Conservation

The growing water footprint due to increased biofuels usage has led to increased focus on water reuse and its conservation in the production of biofuels. In 2005, ~3% of irrigation water worldwide was used for the production of biofuels (UNESCO, 2014). It is predicted that the proportion of irrigated water is expected to be greater than 8% of the total withdrawals by the end of 2030 due to the increased production of biofuels (Ottman, 2008). In the production of biofuels in a dry mill ethanol plant, 30% of the total water consumption goes into the fermentation of corn, which results in the cooking and conversion of the biomass to dextrose. The remaining 70% of the water is used for cooling tower and boiler operations (Minnesota EQB, 2007). As discussed in the above section, cooling water consumption is very high. A major loss of cooling water results from evaporation and drifts (Martín et al., 2010). Methods to reduce the consumption of the cooling water are being investigated. High efficiency cooling systems are a viable option in decreasing water consumption in the cooling tower. Air-cooling using forced convection fans has been proposed and such systems are being used instead of water for system cooling (Aden, 2007). This could potentially decrease the amount of water evaporating from the cooling tower. However, the energy efficiency of dissipating heat is relatively low compared to water-cooling. For cooling water recycling, the water quality should be high in order to avoid scaling inside the cooling tower (Schnoor et al., 2008). One method known as the HiCycler® method, removes hardness of water and silica (Owens, 2007). This is a propriety method, which helps to reduce costs in both cooling water make-up as well as cooling water blowdown (CHEMICO, 2014). This process reduces blowdown by 95%; however, it does not help in cutting the evaporative losses in a cooling tower as it focuses primarily on reducing blowdown losses.

Production of second-generation biofuels is increasing in part due to RFS2 requirements (EPA, 2010; EPA, 2014). Second generation biofuels are fuels that can be manufactured from various types of biomass. Examples of biomass that can be used include lignocellulosic biomass and woody crops such as switch grass and also include crops such as algae (IPIECA, 2012). With second-generation biofuels, the use of membrane filtration is a feasible option that can reduce the amounts of waste produced and water consumed compared to the first generation fuels, such as starch-based ethanol. The production processes related to the first generation biofuels did not focus on increasing the process efficiency, but processes are now being developed to increase the process efficiency in the production of second-generation biofuels (Chem.info, 2010; Koch, 2014). The production of a high concentration ethanol broth is being investigated to reduce the energy consumption during the distillation process (Aden, 2007). A membrane technology, known as pervaporation, is also a potential method to increase the ethanol concentration and thereby reduce water usage. Pervaporation is a method in which two or more miscible components are made to permeate through the membrane. On the other side of the membrane, a vacuum is applied. This evaporates the liquid that passes through the membrane (Ramaswamy et al., 2013; Vane, 2004). The use of graphene oxide-based membranes for the recovery of water for reuse has been investigated. These have been used in an application of pervaporation used to separate water from ethanol (Tang *et al*., 2014). Highly selective membranes can save energy when compared to the present distillation process. However, temperature-sensitive compounds such as the microorganisms, were not suitable for this process (Vane, 2004). The capital costs are higher for heating the compounds, and formation of precipitates may also be a problem at elevated temperatures. If solids are present, microfiltration or centrifugation can be used as an option to remove them. In place of the distillation process, *in situ* biofuel separation within the fermentation broth is under development with the help of membrane processes to improve fermentation performance (Balan, 2014).

Another opportunity for reusing water in the ethanol industry is the use of a novel membrane solvent extraction technology (U.S. EPA, 2011). This patented technology uses a porous membrane that helps to separate ethanol from a fermentation broth using an extracting solvent. The solvent forms an immiscible solution with the extracted ethanol, which can be processed further. By separating ethanol from water, the cooling load decreases, which in turn decreases the use of water. This process can effectively remove ethanol continuously during the fermentation process, which in turn increases the fermentation process and also increases throughput. This process is useful for second-generation ethanol production as it helps in commercializing cellulosic biomass as a feedstock. However, this technology has not been scaled up to pilot-scale operation. The costs involved may also be a barrier when compared with current separation techniques. Another technology, ultrafiltration, is used for clarifying the process stream after conversion into sugars, which is used for the purification of biofuels. A major problem encountered in this technology has been membrane clogging (Khanal, 2010).

Reverse osmosis is used in downstream processing instead of an evaporator for the recovery of water (Cho et al., 2012). This process has reduced operating costs by almost 75% (Jevons, 2011). A reverse osmosis process powered by photovoltaic renewable energy has also been proposed. A disadvantage of this novel technique is that the pressure required to drive the process is heavily dependent on climatic and weather conditions, which in turn, reduces the life of the membrane. Adequate pretreatment of water to remove minerals such as magnesium and calcium ions can be used to prevent scaling in this process. However, this leads to an increase in the operational and maintenance costs. The membrane technology's efficiency depends on the selectivity of the membranes, scale-up of the processes to industrial scale, reliable and consistent long-term performance, and the capital cost required to install these technologies. Another technology proposed for the reuse of water is electrodialysis driven by solar energy (Khanal, 2010). This technology has advantages relative to reverse osmosis technology, as there is no dependence on climatic and weather conditions. However, a major drawback of this technology is that nonpolar compounds cannot be removed.

The technologies to reduce the water consumption in the production of biofuels are primarily focused on the use of membranes. The systems employing membranes are mainly targeted towards reducing the energy consumption, which will in turn reduce water consumption in biofuels production. However, there are some problems that must be resolved in order to use these technologies at a commercial level. The selectivity of the membranes remains a significant issue. The capital costs inherent with these processes also remain an issue, as they need to be cost competitive with currently available processes.

7.6 Summary

In this study, the process and utility water requirements for cellulosic ethanol production has been assessed based on the published data in the literature. The study is not intended for a life-cycle analysis of water usage from biomass production to waste disposal. Instead it is focused on a detailed engineering examination of water usage and the potential for water conservation at a unit operation level for cellulosic ethanol production. Overall, 12 to 17 gallons of water are consumed for each gallon of ethanol production as derived from a mass balance analysis for four combined cases of feedstocks and pretreatment technologies. This is approximately within the range of water-intensities reported for corn ethanol production within Chapter 6 of this report. Among the four cases analyzed, the AFEX pretreatment technology requires less process water (i.e., 13 gal water/gal ethanol) than the dilute acid pretreatment technology (i.e., 17 to 18 gal water/gal ethanol). This is primarily due to the fact that a far greater ethanol yield is obtained when AFEX pretreatment is used for herbaceous feedstocks such as switch grass. Hence, a process water requirement is primarily determined by the combination of a feedstock and a pretreatment technology. The best pretreatment technology for a given feedstock can be determined, and thus a process water requirement for a cellulosic feedstock can also be determined.

Utility water for cooling tower and steam generation accounts for ~40 to 70% of the total freshwater consumption in the process. The utility water requirements for the AFEX pretreatment are higher (i.e., 14 compared to 8 gal water/gal ethanol for the dilute acid pretreatment) due to the chilled water requirements for ammonia recovery. However, the consumption of total process and utility water is not significantly different for the four analyzed cases. The water networks for all cases were designed for zero wastewater discharge. Nonetheless, the use of recycled water will primarily depend on process economics and will be a function of the availability of freshwater make-up, and the capital and operating costs of an on-site wastewater treatment system. Overall, alternative water saving options and advanced cooling tower design are critically important to minimize freshwater consumption.

7.7 References

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8 Biodiesel Production and Impacts on Water Resources

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8.1 Introduction

As a renewable alternative to petroleum diesel, biodiesel has been widely used in the U.S. and around the world. In the U.S., a record high of 1.8 billion gallons of biodiesel (including 1.34 billion gallons of biodiesel with the remainder being renewable diesel) was produced in 2013 (EIA, 2014), compared to 315 million gallons in 2010, 700 million gallons in 2008, and just 25 million gallons in 2004 (Figure 8.1). A decline in biodiesel production from 2008 to 2010 was due to the expiration of the blender's credit in 2008. Oil plant growth requires water (irrigation or precipitation) and water is needed to process oil seed into oil and the oil into biodiesel. As an example, currently soybean remains the dominant biodiesel feedstock in the U.S., which requires a large quantity of irrigation water consumption for growth. The goal of this chapter is to investigate water consumption during biodiesel production.

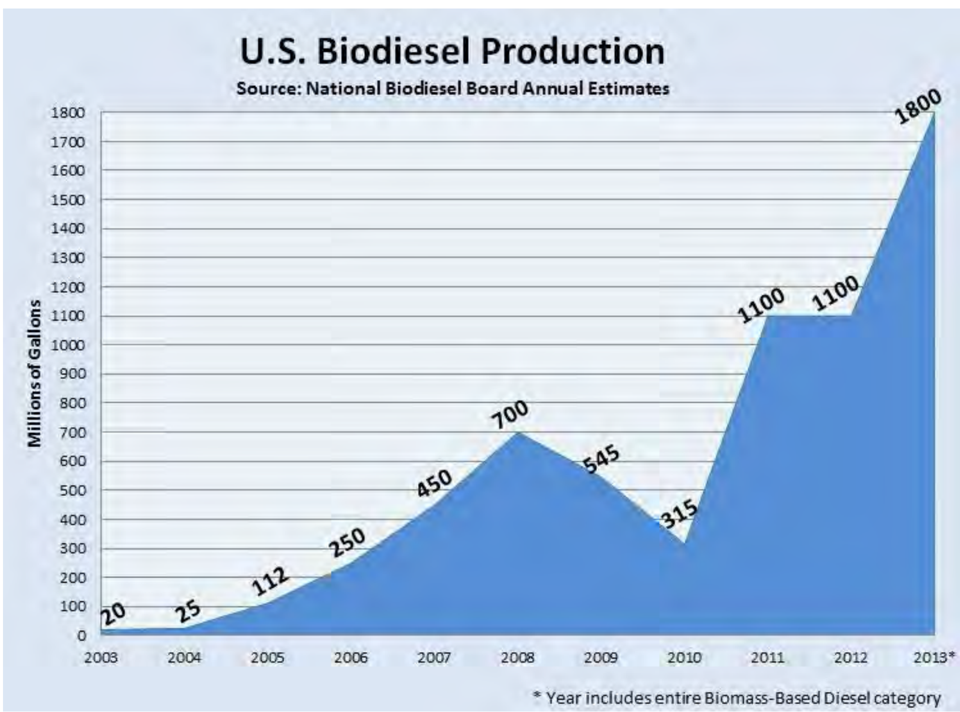

Figure 8.1 Annual biodiesel production in U.S. (2003~2013). Source: National Biodiesel Board (http://www.biodiesel.org/production/production-statistics)

This chapter will begin with a summary of the current status of the U.S. biodiesel industry, followed by an estimate of water consumption for the processing of lipids into biodiesel. Currently, soy oil is the primary source of lipids that are processed into biodiesel fuel in the U.S. The production of soy-based fatty-acid methyl ester (FAME) biodiesel (the biodiesel

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process) are defined as consisting of the following three stages: soybean irrigation, soybean-to-soybean oil processing, and biodiesel manufacturing. This analysis of water consumption from the biodiesel process began with a survey of relevant literature. Water consumption was then estimated by using characteristic allocation factors for each of these three stages. Both state-level estimates and national averages of water consumption were determined within this analysis. Results from this analysis were then compared with several relevant studies in detail. Water consumption patterns of water-stressed areas were also summarized. The chapter concludes with a discussion of future biodiesel trends, including the use of new feedstocks and the use of new biodiesel production technologies since these changes can also affect water use. Water use from algal biodiesel is also briefly summarized.

8.2 Water Consumption Estimates for the Soybean Oil FAME Biodiesel Process in the U.S.

A water consumption analysis for the processing of soybean oil to biodiesel in the U.S. using transesterification to FAMEs was conducted. The analysis aimed at evaluating the water consumption in three stages of the process: soybean growth, soybean oil processing, and soybean oil transesterification to FAME biodiesel.

8.2.1 Methodology

Water consumption in the biodiesel process is estimated as the sum of irrigation water use in the soybean growth stage (W_1), water use during soybean crushing and processing into soybean oil (W_2), and water use in biodiesel production (W_3). Water usage in fuel transportation and distribution was not included due to a lack of data. The water consumption associated with producing energy that is used to move and treat the water was also not included in the scope of this study. Both W_1 and W_2 focus on soybeans as a feedstock due to its dominant market share in biodiesel production in the U.S. and the availability of data. W_1, W_2 and W_3 are expressed in the unit of "million gallons per year (MMgpy)." N_1, N_2 and N_3 are the normalized values for each stage based on biodiesel produced in the unit of "gallons of water per gallons biodiesel (gal/gal)," which is commonly used by other studies (Wu et al., 2009; Pate et al., 2008; Martín and Grossmann, 2012). The parameters for state-level water consumption are expressed as W_{1j}, W_{2j} and W_{3j}, with j representing each state. The overall total water consumption for the U.S. (W_{tot}) is the sum of W_1, W_2 and W_3, and corresponding normalized value N_{tot} is the sum of N_1, N_2 and N_3. As an example, details in estimating of W_{1j}, W_{2j}, W_{3j}, N_{1j}, N_{2j} and N_{3j} for Ohio are provided in the Appendix to this chapter.

8.2.2 Data sources

8.2.2.1 Soybean irrigation stage: irrigation water consumption (W_{1j}, N_{1j})

The "Farm and Ranch Irrigation Survey" (2008 is the most current) was used in this analysis since U.S. Department of Agriculture (USDA) surveys are the most comprehensive surveys of irrigation water use for soybean agriculture in the U.S. (USB, 2010; USDA, 2008). In estimating W_{1j}, the following factors have been considered: the fraction of soybeans processed into biodiesel, the oil content of the soybeans, and the efficiency of the transesterification reaction.

8.2.2.2 Processing soybean into soybean oil stage: crushing, oil extraction, and crude soy oil refining (W_{2j}, N_{2j})

After harvesting, soybeans are transported to the refining plant for crushing, oil extraction, and crude oil degumming. Water consumption in this stage is primarily related to equipment operation, such as cooling tower make-up or water use in free fatty acid (FFA) removal (USB, 2010; van Gerpen et al., 2004). The FFA is usually removed from soybean oil via caustic refining (i.e., neutralizing the FFA with a caustic soda and using water to wash away the soap formed). Other refining practices, such as bleaching and deodorizing are not as considered at this stage since they are less typical. The consumptive water involved was summarized in an aggregated form by the National Oilseed Processers Association (NOPA), which was the result of a representative survey among its member companies in 2008 (USB, 2010).

8.2.2.3 Biodiesel production stage: crude biodiesel purification, cooling tower make-up (W_{3j}, N_{3j})

In biodiesel manufacturing from soy oil, the following processes are found to be associated with water use: biodiesel washing to remove residual glycerin and other impurities, boiler make-up, and cooling tower make-up. The actual consumption can vary considerably depending upon the system setup and the extent of heat economization used in the facility. Due to the pretreatment requirements for the wash water prior to discharge, waterless separation/purification or "dry-wash" technologies are increasingly practiced by biodiesel producers to replace water washing. Even for water washing, the wash water is reused instead of being discharged after one use. Boiler water make-up should be considered when distillation is used to separate glycerin and other impurities from biodiesel, and the rates vary depending on the distillation processes (vacuum or steam distillation) used in the facilities. The resultant boiler water make-up from vacuum distillation can be much lower than for steam distillation. Cooling tower make-up water should be considered in W_3 if the producer uses evaporative cooling towers to condense process vapors (such as for methanol recovery) and cool liquid process streams. In this analysis, these data were collected from actual biodiesel producers in addition to using data from published literature (Tu et al., 2014).

8.2.2.4 States reporting zero water use

Fifteen states (Alaska, Arizona, California, Florida, Hawaii, Idaho, Montana, Nevada, New Hampshire, New Mexico, Oregon, Pennsylvania, Rhode Island, Utah and Wyoming) are not included in the calculation of W_{1j} and N_{1j}, either due to negligible soybean growth or lack of irrigation data from the USDA. Of these 15 states, the states of Florida, Montana and Pennsylvania have sufficient soybean harvest data and accordingly are included in the calculation of W_{2j} and N_{2j}

Four states (Colorado, Montana, Vermont and Wyoming) were not included in the calculation of W_{3j}, total and normalized water consumption during the biodiesel manufacturing stage, because there was no biodiesel production in those states prior to conclusion of this analysis.

8.2.3 Results

8.2.3.1 Water consumption in soybean growth stage (W_{1j}, N_{1j})

Appendix Figures 8.1 and 8.2 (see Chapter 8 Appendix) show the results of irrigation water consumption (W_{1j}) and irrigation water intensity (N_{1j}) for soybean agriculture dedicated to biodiesel production in 35 states in the U.S. While W_{1j} is a direct reflection of irrigation water consumption, N_{1j} is an important measure of irrigation intensity regardless of the soybean growth scale for a specific state. The irrigation water use W_{1j} varies significantly from state to state, 0.00 to 15,953.00 MMgpy. The range of normalized irrigation intensity (N_{1j}) varies from 1058.20 gal/gal (Washington) to 0.00 gal/gal (states with minimal irrigation) with the weighted nationwide average (N_1), median and weighted standard deviation being 61.78, 23.67 and 147.92 gal/gal, respectively.

The states with negligible irrigation consumption (0.00 MMgpy) were Massachusetts, Connecticut, Maine, Vermont, West Virginia and New York, primarily due to limited soybean growth. In fact, Massachusetts, Connecticut, Maine, Vermont, West Virginia and New York rank 35th, 34th, 33rd, 31st, 29th and 23rd in terms of total amount of soybeans harvested. On the other hand, the states with the highest irrigation water use, Arkansas (15,953.00 MMgpy), Nebraska (9056.78 MMgpy), Mississippi (3714.78 MMgpy), Kansas (2514.84 MMgpy) and Missouri (2456.94 MMgpy), are also major soybean producers, ranking 10th, 6th, 14th, 11th and 7th among the 38 states that reported soybean harvests.

The irrigation water intensity of 11 states (Washington, Arkansas, Colorado, Mississippi, Nebraska, Texas, Delaware, Kansas, Louisiana, Georgia and Oklahoma) are above the national average, with values of 1058.20, 674.30, 611.52, 285.90, 199.74, 190.08, 148.21, 127.09, 108.59, 106.75 and 88.13gal/gal, respectively. These 11 states represent 18.32% of the total soybean harvest, and 36.10% of total biodiesel production capacity. As previously mentioned, Arkansas, Mississippi and Nebraska are three states with both significant soybean growth and significant irrigation water consumption. Although the states of Washington and Colorado have very high irrigation water intensities, their total irrigation water consumption (W_{1WA}, W_{1CO}) is lower than the national average due to much less soybean cultivation. On the other hand, Iowa, Illinois, Minnesota, Indiana and Ohio account for 56.37% of U.S. soybean production, while their irrigation water intensities are only 1.88, 4.01, 8.60, 7.85 and 0.71gal/gal, respectively. The much lower N_{1j} values reported in states such as Illinois, Indiana, Iowa, Kentucky, Minnesota, North Dakota, Ohio, South Dakota, Tennessee, etc., are due to much less irrigation used in soybean production in these states.

The vastly different irrigation ratios (irrigated acres vs. total acres) are the primary contributing factors with respect to the wide range of state level irrigation water intensities. The average irrigation ratio is 8.2% among these 35 states, with the range of 0% to 65.40% (with the highest irrigation ratio for Arkansas), and 25 states have irrigation ratios below average. For the top five soybean producing states, soybean irrigation ratios range from 0.02% to 1.72%. These results indicate that it may be advantageous to grow soybeans where less irrigation is needed rather than in states that have high irrigation ratios. Due to the significant variation in irrigation practices among U.S. states, a simple national average cannot accurately represent water use.

8.2.3.2 *Water consumption in the soybean processing and refining stage (W_{2j}, N_{2j})*

A uniform value of the N_2 (0.17 gal/gal) was used for calculation of water consumption, and the range of W_{2j} varied from 0.003 to 112.00 MMgpy.

8.2.3.3 *Water consumption in the biodiesel production stage (W_{3j} and N_{3j})*

Water consumption data for the biodiesel washing process varies significantly among different studies. The National Biodiesel Board (NBB) estimated that one pound of wash water was needed for four pounds of biodiesel, which is equivalent to 0.22 gal/gal (Scott, 2010). The United Soybean Board (USB) conducted a life cycle assessment (LCA) for the soybean-to-biodiesel process, where water used for biodiesel washing was reported as 0.26 gal/gal (USB, 2010). However, the water consumption reported from simulations was 0.03 (Haas *et al*, 2005) and 0.01 gal/gal (Zhang *et al*., 2003), respectively.

The substantial difference in water use among data sources warranted data collection from actual biodiesel manufacturers. In this analysis, inquiries were sent to 123 commercial biodiesel producers listed by the NBB[34]. A total of 21 replies were received, among which six reported water washing, 11 indicated dry purification or "dry washing" and four considered this information proprietary. The weighted average water consumption based on plant capacity was 0.12 gal/gal for biodiesel washing (Appendix Table 8.3). Therefore, water consumption in biodiesel washing for this analysis was determined to be in a range from 0.12 to 0.26 gal/gal for water washing processes and 0 gal/gal for dry washing.

The dry wash method often consumes less water during distillation compared with water washing. Water consumption for cooling tower make-up is presented in Appendix Table 8.4. This again indicates the highly process-specific characteristics of actual biodiesel production operations. The water consumption of cooling water make-up was averaged based on plant capacity, and was also separately analyzed for dry washing and water washing. Accordingly, the cooling tower make-up for water washing was 0.275 gal/gal and was 0.153 gal/gal for dry washing. Only limited information was available on boiler water make-up and the extent of dry wash use among biodiesel producers, so these were assigned zero values.

The water consumption rates in biodiesel production (N_3) were summarized based on three scenarios: water washing (upper range), water washing (lower range) and dry washing with the corresponding values for N_3 being 0.54, 0.4 and 0.15 gal/gal, respectively. On average, dry washing consumes approximately one third of the total water consumed within the biodiesel manufacturing process. A uniform N_3 of 0.31 gal/gal was calculated by averaging the three scenarios. Accordingly, the resultant water consumption in biodiesel production (W_{3j}) was estimated based on N_3 and biodiesel capacities in each state.

In 2013, 46 out of the 50 states have biodiesel plants in operation (with no commercial-scale biodiesel production in Colorado, Montana, Vermont and Wyoming). Texas has the highest biodiesel production capacity in the U.S. (577 MMgpy), followed by Iowa, Missouri, Illinois and Ohio. The average capacity is approximately 64 MMgpy per state, and detailed production capacities in each state are summarized in the appendix (Appendix Table 8.1). The biodiesel

[34] The NBB maintains a list of biodiesel producers on the Internet at the following URL: http://www.biodiesel.org/production/plants, accessed June 2014.

production capacities in the 46 biodiesel producing states varied from 0.25 MMgpy in Alaska to 577.25 MMgpy in Texas. Assuming that the purification and process water consumption rate N_3 (0.31 gal/gal) is uniformly applied to all biodiesel plants, the resultant W_{3j} ranges from 0.08 to 178.47 MMgpy (see sample calculations in the Appendix to this chapter). As dry wash technologies are increasingly practiced among the biodiesel industry, the water consumption for this stage of biodiesel processing is expected to decrease with time.

8.2.3.4 *The total annual water consumption by states ($W_{tot,j}$, $N_{tot,j}$)*

The total quantity (W_{tot}) of consumptive water as the sum of water consumption from the three stages is summarized for each state as the sum of water consumption in irrigation (W_1), soybean–to-soybean oil processing (W_2) and biodiesel production (based on capacity, W_3). The fractions of water use at each stage are also estimated to better understand the relative contribution. Figure 8.2 illustrates the total consumptive water ($W_{tot,j}$) for the soybean-to-biodiesel process in each state. 49 states are included in this figure, with the exception of Wyoming which had neither soybean growth/processing or biodiesel plants in 2007/08. $W_{tot,j}$ ranges from 0.004 MMgpy to 16,016.11 MMgpy in these 49 states. Figure 8.3 shows the normalized total water consumption for 49 biodiesel producing states. The range of $N_{tot,j}$ varies from 0.17 gal/gal to 1058.68 gal/gal, with a national average of 62.26 gal/gal. On average, irrigation represents 99.23% of the total water consumption, 0.27% for soybean crushing/refining and 0.50% for biodiesel manufacturing. However, the fractions vary significantly among the states.

Water consumption for the ten states with the highest soybean harvest is listed in Table 8.1. These represent 83.31% of soybean harvest in the U.S. in 2008 (USDA, 2008). Most of these major soybean-growing states are located in the Midwest region with the exception of Arkansas. The irrigation water intensities (N_{1j}) of these states are below national average with the exception of Arkansas, Nebraska and Missouri. This again supports the fact that not all soybeans in the U.S. are irrigated, and warrants further state level water consumption analysis.

Table 8.2 lists water consumption for the ten states with the highest biodiesel capacities. These ten states account for 66.6% of biodiesel production capacities in 2013 (Biodiesel Magazine, 2013). The states of Arkansas (#1 in irrigation water use), Mississippi (#3), Missouri (#5), Indiana (#8), Illinois (#9) and Iowa (#14) are both the highest in irrigation water use (not necessarily entirely soybean production) and biodiesel production. This may be an indication that the soybeans produced have been consumed in close proximity, as biodiesel plants usually seek nearby feedstock to reduce the cost of transport and storage. In contrast, water use from biodiesel production accounts for a much larger fraction in the states of Washington and Pennsylvania when compared with soybean irrigation, as soybean growth in these states is relatively low.

It is noteworthy that in most of the states, W_{1j} and W_{3j} dominate the total water consumption for biodiesel production except for Ohio, Illinois and Iowa where W_{2j} consumptions account for 28.04%, 19.02% and 40.53% of water use in their biodiesel processes, respectively. This is due to high soybean harvest (5th, 2nd and 1st in the U.S., respectively), and therefore a high percentage of water use in soybean oil processing.

Table 8.1 Total annual water consumption ($W_{tot,j}$) in top 10 soybean harvesting states*

State	$W_{tot,j}$ (MMgpy)	$W_{1j}/W_{tot,j}$ (%)	$W_{3j}/W_{tot,j}$ (%)
Iowa	400.577	48.46	23.50
Illinois	484.8529	69.91	11.07
Minnesota	622.8166	85.84	3.28
Indiana	488.7905	81.09	7.65
Ohio	123.2441	26.36	33.11
Nebraska	9107.751	99.44	0.02
Missouri	2556.946	96.09	2.22
South Dakota	289.2936	87.50	0.75
North Dakota	139.1979	60.49	19.55
Arkansas	16016.11	99.61	0.23

Note: * - Ranked by harvest.

Table 8.2 Total annual water consumption ($W_{tot,j}$) in top 10 biodiesel producing states*

State	$W_{tot,j}$ (MMgpy)	$W_{1j}/W_{tot,j}$ (%)	$W_{3j}/W_{tot,j}$ (%)
Texas	335.77	45.58	53.16
Iowa	400.58	48.46	23.50
Missouri	2,556.95	96.09	2.22
Illinois	484.85	69.91	11.07
Ohio	123.24	26.36	33.11
Indiana	488.79	81.09	7.65
Arkansas	16,016.1	99.61	0.23
Mississippi	3,764.65	98.68	0.95
Washington	41.98	16.75	83.23
Pennsylvania	34.85	0	98.70

Note: * - Ranked by plant capacities

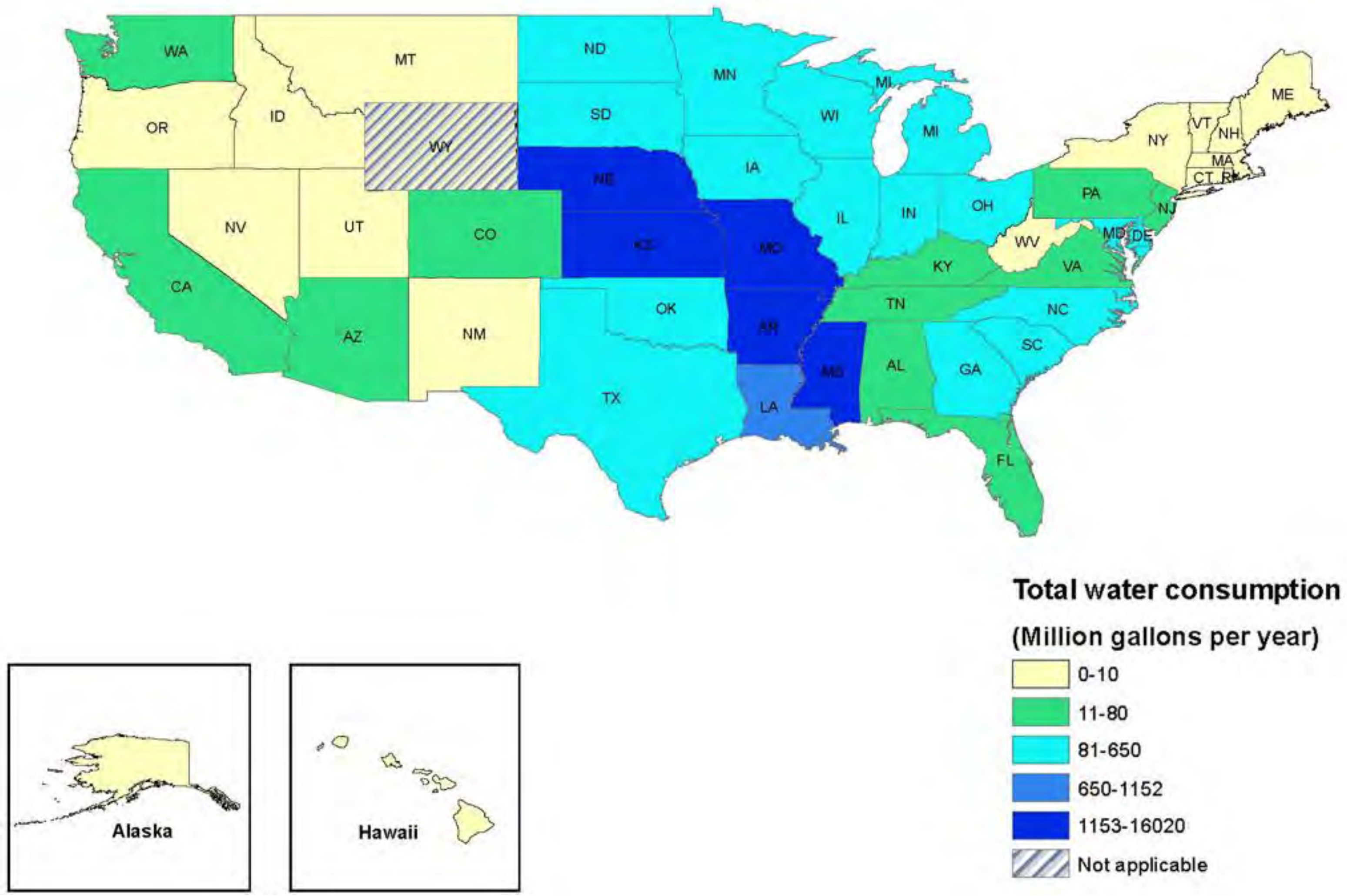

Figure 8.2 Total annual water consumption of the soybean-to-biodiesel process ($W_{tot,j}$).

Consumption includes irrigation (USB, 2010; USDA, 2008), soybean processing into oil (USB, 2010) and biodiesel production from oil (Tu et al., 2014).

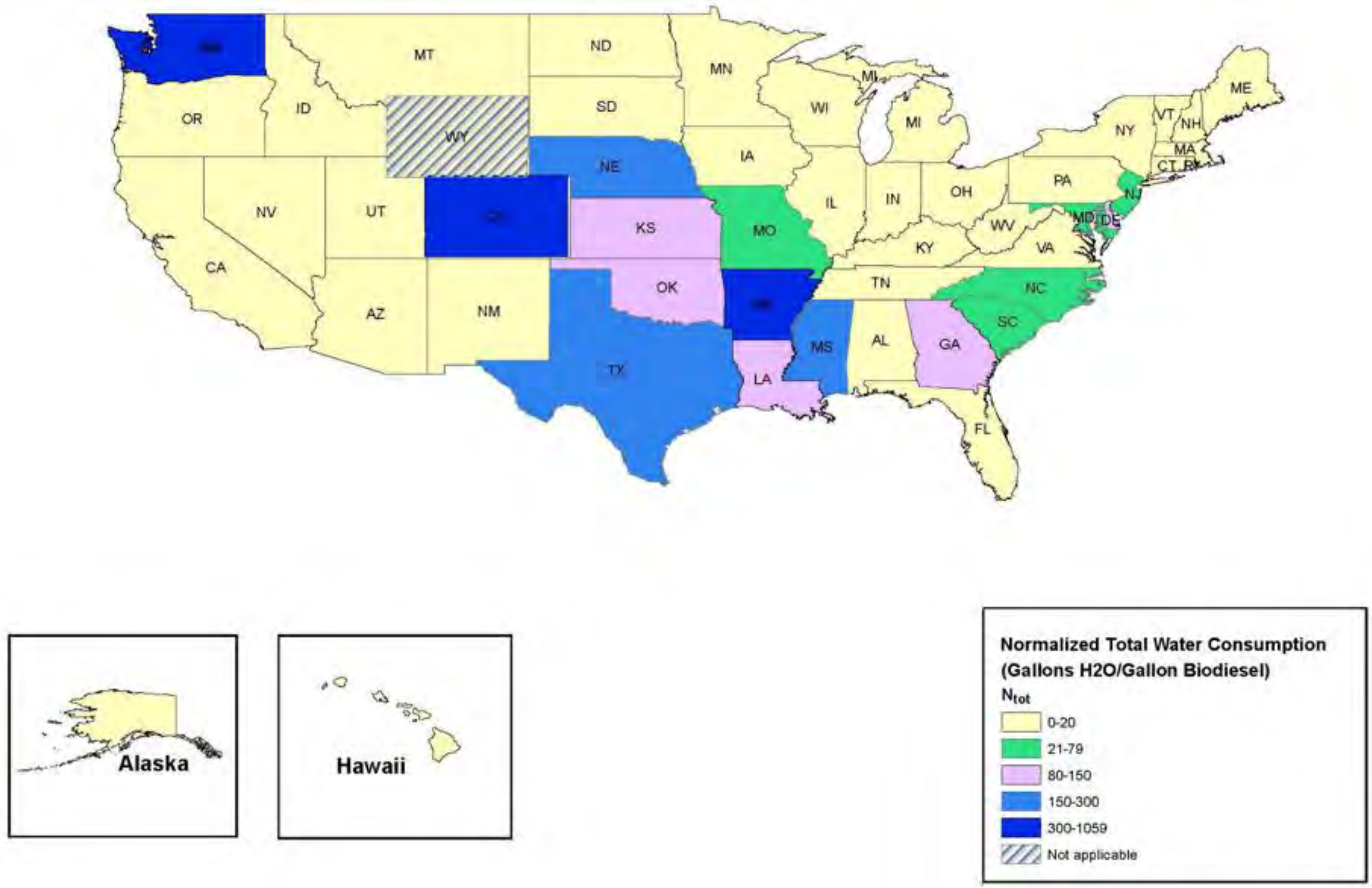

Figure 8.3 Total water consumption of the soybean-to-biodiesel process on per gallon biodiesel basis ($N_{tot,j}$). Data from USB (2010), USDA (2008), and Tu et al. (2014).

8.2.4 Discussion

8.2.4.1 Regional impact analysis

In this analysis, regional water use for biodiesel processing was also determined by grouping the states into nine census regions (Doddler et al., 2011). Regional data averages out differences among states as found in our study. Table 8.1 indicates that water use for the biodiesel process mainly impacts the water resources in the Midwestern and Southern regions of the U.S. Table 8.2 indicates that nine out of the ten top soybean growing states are in the East North Central and West North Central regions, except for Arkansas in the West South Central region. The states of South Dakota and North Dakota have high soybean harvests but are below the national average in irrigation water use and total water use.

In Table 8.3, water consumption of the biodiesel process for each region is evaluated by the fractional percentage of water consumed for irrigation (P_1) and biodiesel manufacturing (P_3) for each region, and also the regional irrigation intensity ($N_{tot\text{-}region}$).

Table 8.3 Regional water consumption data

	W_{tot} (MMgpy)	P_1 (%)	P_3 (%)	$N_{tot\text{-}region}$ (gal/gal)
New England	4.22	0.00%	99.25%	0.48
Middle Atlantic	60.95	23.73%	73.10%	8.65
East North Central	1617.51	76.11%	9.73%	6.34
West North Central	15654.20	96.43%	1.30%	46.7
South Atlantic	981.66	90.32%	7.74%	51.9
East South Central	3892.92	97.35%	1.94%	150
West South Central	17114.78	98.44%	1.36%	536
Mountain	42.16	51.50%	48.40%	552
Pacific	71.78	9.80%	90.19%	1059

The West South Central (TX, OK, AR and LA) region accounts for 43.35% of the total water consumption for biodiesel production and 5.13% of soybean harvest (the 3rd highest in the U.S.). State-level data indicates that the high water consumption was primarily caused by relatively high irrigation water intensities in AR, LA and OK, and large biodiesel production capacity in Texas. The West North Central region had the second largest water consumption, representing 39.65% of total water consumption, but with low total water intensity. The region represents 53.25% of soybean growth in the U.S. and 22.5% biodiesel capacity. New England (six states) accounts for approximately 0.01% of the irrigation water consumption in the U.S., and this is predominantly from biodiesel manufacturing. Similar trends can be observed in the Pacific and Middle Atlantic regions. The highest regional water intensity in the Pacific region is due to the irrigation water intensity in Washington. Together, from Figures 8.3 and 8.4, it was observed that the water use varies vastly within the West North Central. Agricultural water use in Nebraska and Kansas is much larger than the national average, while such water use in other states is less than the national average. This regional heterogeneity is also evident for the West South Central, East South Central and South Atlantic Regions.

Given the large variations among states within the same region, from a planning and decision making standpoint, state level soybean water use data can be considerably more accurate than regional data.

8.2.4.2 Water-stressed areas

For areas where the water supply is potentially constrained, the impact of biodiesel production on water resources should also be analyzed with respect to future climate adaptation considerations. A few studies have identified the water-stressed areas based on different criteria, as summarized in Appendix Table 8.5. Accordingly, the following states are identified as water-stressed in this study: Arizona, California, Colorado, Florida, Georgia (especially southern Georgia), New Mexico, Nevada and Texas (WRI, 2014). Accordingly, a summary of total annual water consumption ($W_{tot,j}$) is found in Table 8.4.

Table 8.4 Total annual water consumption ($W_{tot,j}$) for soybean biodiesel production in the states in the water-stressed areas

State	$W_{tot,j}$ (MMgpy)	$W_{1j}/W_{tot,j}$ (%)	$W_{3j}/W_{tot,j}$ (%)
Arizona	14.84	0	100
California	24.26	0	100
Colorado	21.75	99.82	0
Florida	12.13	0	99.46
Georgia*	225.24	90.36	8.72
New Mexico	0.46	0	100
Nevada	0.31	0	100
Texas*	335.77	46.58	53.16

Note: * Southern Georgia (Yang et al., 2011) and two-thirds of Texas (WRI, 2014) have been reported as water stressed areas

These states represent 1.6% of total water use, 0.46% of soybean harvest and 27.61% of biodiesel production capacity in the U.S. The total water consumed for all stages of biodiesel processing in these states is much lower than the national average of 1,152.05 MMgpy. For the States of California, Arizona, Florida, New Mexico and Nevada, more than 99% of the water consumption is in biodiesel production from oil due to very limited soybean growth in these areas. Colorado and Georgia only account for 0.32% of the total soybean harvested and 0.63% of total water consumption in the U.S., however, the irrigation intensity in Colorado is 611.52 gal/gal, the 3rd highest in the U.S., while Georgia ranks 10th with respect to irrigation water intensity at 106.8 gal/gal. Texas accounts for 0.13% of total soybean growth and 19.71% of biodiesel production capacity in the U.S., while its irrigation water intensity of 190.58 gal/gal is the 6th highest.

For companies located in water-stressed areas, such as Company 2 (Appendix Table 8.3) in Texas and Company 4 in California, the adoption of water-saving technologies may be more critical. If biodiesel production is to expand in these areas, water supply issues should be considered within the decision making process.

8.2.4.3 Comparison with existing studies

Appendix Table 8.6 provides a detailed comparison of analysis contained within this report compared with other similar studies by evaluating different parameters and assumptions used. In the soybean growth stage, all studies except King and Webber (2008) assumed a complete consumption of irrigation water (i.e., none of the applied irrigation water was recycled or reused). Different irrigation ratios were used within these studies. The analysis within this report is consistent with O'Connor (2010) in irrigation water intensity, and its water intensity in biodiesel manufacturing (N_3) is within the same range as King and Webber (2008) and Harto et al., (2010). All of these studies, and this analysis, found that the water intensities within soybean oil processing and biodiesel manufacturing were much smaller than agricultural irrigation water intensity.

O'Connor (2010) used an overall irrigation ratio of 8.2% by dividing irrigated acres of soybean over total harvested acres. King and Webber (2008) separated the calculation by either non-irrigation or 100% irrigation scenarios. Harto et a*l*. (2010) averaged the irrigation ratios from low, middle and high cost soybean farms, resulting in a national average of 4%. Mulder et al (2010) did not specify an irrigation ratio. Only King and Webber (2008) and the analysis within this report quantified water intensity during the soybean processing stage (N_2). For the biodiesel manufacturing stage (N_3), both King and Webber (2008) and Mulder et al. (2010) cited data from Sheehan et al. (1998), and their values were 0.158 gal/gal and 3.63 gal/gal respectively. Harto et al. (2010) used a value of 1 gal/gal from a 2006 U.S. DOE report (U.S. DOE, 2006). The N_3 used in this study is based on more current data from the biodiesel industry. For the actual water use in "million gallons per year (MMgpy)," the values obtained in this study are expected to be much lower than others since only 17% of the soybean oil was processed into biodiesel. Substantial data variation exists among individual states, which is an indication that state level data is likely to be more accurate than both the national average and the regional data.

8.2.4.4 Limitations of current study

Although only parts of Texas (WRI, 2014) and southern Georgia (Yang et al., 2011) are considered water-stressed areas instead of the entire state in each case, data is only available at the whole state level, so the estimates in Table 8.3 are for entire states. In estimating W_2 and W_3, uniform allocation factors have been used, instead of using state-specific allocation factors due to data limitations. For W_3, the 0.31 gal/gal may decrease as dry-wash methods are increasingly adopted by biodiesel manufacturers.

Indirect water consumption such as water consumed during fertilizer production and water use for energy generation was not included in this analysis. Water loss factor was not accounted for during the irrigation stage (i.e., irrigation water input during the irrigation was assumed to be 100% consumptive).

In real-life situations, some biodiesel producers import soybean oil from other states to meet demand, especially those in the states where soybean growth is minimal (e.g., CA and

WA). The introduction of imported soybean oils may change the N_{Ij} of the biodiesel produced in a specific state, since usually there is a significant difference in the irrigation application between states. Considering the fact that major soybean producing states such as IA and OH have more than enough soybean oil available to meet the demand for in-state biodiesel production, it is likely that the interstate export of soybean oil from these states may help to reduce the N_{Ij} of soybean biodiesel produced in other states. To quantify this phenomenon, robust data is needed for the soybean oil trade across state boundaries for biodiesel production. Unfortunately, such data is not readily available.

8.3 New Trends in Biodiesel Research and Development

8.3.1 Feedstock development

Concerns have been raised about the first generation of biofuels, namely corn ethanol and soybean biodiesel, regarding the diversion of agricultural resources away from food production (Canali and Aragrande, 2010; Casman and Liska, 2007; Tilman et al., 2009). Since feedstock cost constitutes the highest fraction of the biodiesel production cost, newer and lower cost feedstocks may provide attractive alternatives to the biodiesel industry while meeting national policy goals for reducing dependency on fossil fuels. With more R&D on new feedstocks and/or commercialization, the water use of these new feedstocks should also be studied in the future. Based on various sources, the following feedstocks are discussed in this section: distiller grains from corn ethanol, renewable diesel, algae and waste feedstocks.

8.3.1.1 Distillers dried grains with solubles (DDGS) from ethanol plants

Distillers dried grains with solubles (DDGS) is a by-product from the ethanol manufacturing process. Currently, the primary outlet for DDGS is livestock feed (Klopfenstein et al., 2007; Lumpkins et al., 2004; Shurson, 2002). However, the expansion of the bio-ethanol industry has generated more than enough DDGSs, which is essential to make good use of in order to keep the production cost low. Extraction of residual oil from DDGS for biodiesel production has been proposed (Liu and Rosentrater, 2011). The potential feedstock supply from recovered oil from ethanol plants is estimated to reach as high as 680 million gallons in 2022 (U.S. EPA, 2010). On average, residual oil takes up approximately 10 wt% of DDGS. The FFA level in the extracted oil varies from case to case, with typical values of approximately 13 to 15% (Haas, 2011). One potential concern is high wax concentration in the resulting biodiesel from the recovered oil, since certain components of wax, such as steryl glucosides, are likely to precipitate out when biodiesel is cooled, causing filter clogging. One way to solve this problem is to apply a "winterization" processing step to fractionalize the wax components and remove them from the biodiesel.

8.3.1.2 Renewable diesel

"Renewable diesel," also called "second generation biodiesel," refers to hydrocarbon based diesel fuel refined from renewable sources, such as plant oil, fats or biomass instead of from petroleum. Renewable diesel can come from three processes: hydro-treatment of biomass, hydro-thermo processing of oils (vegetable oil and animal fat) and via the Fisher-Troche (F-T) process. The key process is decarboxylation as opposed to the transesterification that is used to produce FAME biodiesel (Knothe, 2010). Under the revised Renewable Fuel Standard (RFS2) program, renewable diesel is credited at 1.7 RINs per gallon compared with 1.5 RINs per gallon for biodiesel (primarily FAME). Industrial scale development investments have been made to produce renewable diesel fuel. Neste Oil, a Finland-based oil refining company, has a production capacity of up to 600 million gallons per year (MMgpy). In the U.S., Dynamic Fuels possesses a renewable diesel plant with a production capacity of 75 MMgpy. Renewable diesel production facilities under construction in the U.S. include a 137 MMgpy plant by Diamond Green Diesel and an 85 MMgpy plant by Emerald Biofuels.

At first, renewable light-distillate fuel oils such as renewable diesel fuel and renewable jet fuel are of particular interest to the aviation industry and military since in these two sectors, vulnerability to the filter clogging and other cloud-point-temperature issues of biodiesel under cold climate conditions limits its application. Renewable diesel and jet fuels may be particularly suited for these applications since they can be processed into short chain paraffins that will not cause the crystallization of fuel under cold weather conditions. But renewable diesel can have wider usage, as it can essentially replace petro-diesel.

Neste Oil has been in collaboration with Lufthansa for test flights of their renewable aviation fuel (Reuters, 2012). In the U.S., UOP demonstrated the performance of their renewable jet fuel in five aircraft from Gulfstream Aerospace as part of a trip from Gulfstream's headquarters in Savannah, GA to Orlando, FL, where the National Business Aviation Association (NBAA) convention was being held (PR Newswire). During an air show in Maryland, two U.S. Air Force F-16 aircrafts also used UOP renewable jet fuel (UOP, 2011). The U.S. Navy has initiated several tests of algae-based renewable diesel in their vessels. Based on initial success in small vessels, the Navy continued to test biodiesel with one of its destroyers. The test is part of the program named the Navy's Green Fleet Initiative, which aims to form the capability of deploying a Navy fleet that is powered entirely by alternative fuels (Casey, 2011).

It is still not possible to draw any definitive conclusions regarding water consumption associated with renewable diesel production based on the current literature because only very limited literature exists. As renewable diesel generally uses the same oil feedstocks as biodiesel, the differences in water consumption reside within the renewable diesel manufacturing processes. An initial life-cycle assessment published by Argonne National Lab (ANL) reported that producing 84.19 lb renewable diesel (out of 100 lb feed oil) by UOP process generated 6.11 lb wastewater and required cooling water input (partially consumed) of 1,356 lb (ANL, 2008).

8.3.1.3 Algae

Research on algal biofuel began in the 1970s and has been a subject of considerable research in recent years (NRC, 2012; U.S. EPA, 2010). The lipid content of most algae species are higher than that of conventional oil crops (Mata *et al*., 2010), which makes algae a promising feedstock to produce significant amounts of biofuel in the U.S. (Chisti, 2007). As compared with conventional oil feedstocks, the cultivation of microalgae requires less land use in general, and the use of algal oil is not competing with human consumption of edible oil (Singh *et al*., 2011). However, there are limited amount of algae biofuel companies that are able to grow algae and produce biofuel in a commercial scale. It was estimated that 100 million gallons of algal biodiesel would be produced in the U.S. in 2022 (U.S. EPA, 2010).

U.S. DOE (2010) laid out an algal biofuel technology roadmap, which listed areas of research and development needed for future production of algal biofuels. In addition to the technical and economic hurdles, water consumption is another significant obstacle in front of the commercialization of algal biodiesel, considering the nature of algae growth.

8.3.1.4 Water consumption in algal biodiesel production

As part of the analysis of biodiesel production for this report, we collected feedback from expert biodiesel industry sources (National Renewable Energy Laboratory, USDA, NBB and biodiesel producers) regarding future trends of the biodiesel industry. Algae were recognized as having potential to be a significant future biodiesel feedstock. A National Academies' report (NRC, 2012) highlighted some concerns with respect to algal biofuel production, such as water and nutrient demands, low energy output, leakage, etc.

As described by DOE's algae technology roadmap (U.S. DOE, 2010) and within the report by the National Academies (NRC, 2012), many technical issues still need to be solved, such as improving algal strains for desired characteristics, advancing the materials and methods for growing and processing algae into fuels, reducing energy requirements for multiple stages of production, etc.

Preliminary findings from our analysis of algal biodiesel production are presented in this section. Similar to the analytical approach used within this report with respect to water use in the soy biodiesel production process, water use in algae to biodiesel processing was also determined primarily in the form of a summary of existing literature. The results showed that freshwater consumption can be a significant concern if algae biodiesel is to undergo commercialization. Switching to saline and/or wastewater use may be a potential solution.

Water is used in the following algal biodiesel processes: open pond cultivation, harvesting and dewatering, algal oil extraction and biodiesel production via transesterification. Water consumption during algae cultivation is mainly caused by the need to make up for the evaporation losses. The evaporation loss in an open pond system is primarily affected by local topography and by climate conditions. At the algae harvesting stage, dewatering is necessary to reduce the carry-over water in the algae biomass down to a level at which it can be successfully processed through oil extraction. In the harvesting and dewatering steps, water may be lost by evaporation.

After algae are harvested and dewatered, extraction (e.g., by hexane) is performed to separate the lipids from algae cells. The extraction process involves solvent recovery, which requires make-up water for extraction facilities that include a boiler and cooling tower. The water consumption during the biodiesel production stage includes crude biodiesel purification (water washing) and process-related water consumption (e.g., make-up water for the cooling tower).

Table 8.5 summarizes the water consumption in these steps from several studies. These studies were all focused on freshwater consumption. Harto et al. (2010) calculated the evaporation losses that occurred in open pond systems based in the Southwest U.S. Water consumption ranged from 32 gallons of water for 1 gallon of biodiesel to 656 gal/gal, depending on the evaporation rates, with an average of 216 gal/gal. Wigmosta et al. (2011) calculated the evaporative loss of freshwater in an open pond system using the Modular Aquatic Simulation System 2-D (MASS2). MASS2 is a two-dimensional, depth-averaged hydrodynamic and transport model developed at Pacific Northwest National Laboratories (PNNL, 2004). As a result, the consumptive freshwater use due to evaporation was 1,421 gallons water per gallon biodiesel. Yang et al. (2011) also investigated the freshwater consumption in an open pond from algae cultivation to oil transesterification. A value of 591 kg water/kg biodiesel (i.e., 520 gal/gal) was calculated when harvested water was recycled. Pate (2008) estimated a 1,000 gal/gal evaporative water loss for a cooling photobioreactor based on a 50 MMgpy scale. Guieysse et al. (2013) studied the variation of freshwater consumption by algae growth in five different climatic regions and the results showed that the water footprint (WF) varied from 33.1 m^3/GJ to 36.7 m^3/GJ (1,093 gal/gal to 1,212 gal/gal).

The "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis" released by U.S. EPA (2010) contains a LCA study on algae biodiesel conducted by the National Renewable Energy Laboratory (NREL). The authors evaluated three scenarios for the algae growth. The base case assumed the yield of algae to be 25 g/m^2/day in an open pond and 63 g/m^2/day in a photobioreactor (PBR). The lipid concentration was assumed to be 25%. In the aggressive case, the yield was 40 g/m^2/day (op) and 100 g/m^2/day (PBR), and the lipid concentration was 50%. The third scenario, the max case, assumed the yield to be 60 g/m^2/day (open pond) and 150 g/m^2/day (PBR), with a lipid concentration of 60%. The result of net water demand showed that water consumption in an open pond was significantly higher than a PBR, and increasing yield and lipid concentration was an effective approach to reduce the total water consumption for algae cultivation. Overall, the water consumption of algae biodiesel production is higher than that of biodiesel derived from soybean (62.26 gal/gal; this study) and waste cooking oil (0.33 gal/gal; Martín and Grossmann, 2012), corn ethanol (10.1 gal/gal; Wu et al., 2009) and cellulosic ethanol (1.9-9.8 gal/gal; Wu et al., 2009) reported in the literature. It is also notable that the water consumption during the biodiesel production stage is significantly lower than the cultivation, harvest and dewatering stages. This was also observed by Tu (2012) through a water consumption analysis for soybean biodiesel production in the U.S.

8.3.1.5 Water saving methods

In general, water savings can be achieved through using alternative water resources (e.g., saline water, municipal wastewater), improving reactor design and applying innovative harvesting and extraction technologies.

- *Cultivation*

- Species for saline water

Utilizing algae strains that are tolerant to saline water is expected to divert the algal biofuel production towards reduced use and consumption of freshwater resources. Current efforts are focused on isolating and genetically modifying marine and brackish algae species to accommodate them for lipids production. Examples include a genetic manipulation of *Dunaliella tertiolecta*, (Lane, 2012) and certain strains of *Nannochloropsis sp*. and *Chlorella sp*., which possess both high lipid content and a preferred fatty acid profile that are crucial to successful biodiesel production (Lim et al., 2012). Although growing salinity-tolerant algae for oil production slows freshwater depletion, freshwater input is still necessary for preventing salt build-up within ponds (Vasudevan et al., 2012). Murphy and Allen (2011) calculated the saline and freshwater consumptions for massive cultivation of algae in open ponds. The results showed a national average water consumption of 5.5 m^3/m^2 (4.4 m^3/m^2 saline and 1.1 m^3/m^2 freshwater) per year. The utilization of these saline strains of algae can be promising as it will reduce the use of freshwater.

Table 8.5 Literature summary of water consumption during different algal biodiesel production stages*

Study	Cultivation	Harvest & Dewatering	Oil Extraction	Biodiesel Production	Total
Open Pond (OP)					
Harto et al. (2010)	165	50		1	216
Wigmosta et al. (2011)	1421	NA			1,421
Yang et al. (2011)	514		6		520
Guieysse et al. (2013)	1093-1212	NA			1,093-1,212
RFS2 RIA (2010)	974[a], 383[b], 317[c]	NA			974, 383, 317
Photobioreactor (PBR)					
Harto et al. (2010)	0	40	1		41
Pate (2008)	1000	NA	1		1,001
RFS2 RIA (2010)	72[a] 32[b], 25[c]	NA			72, 32, 25

Note: * - All consumption in units of gallons of water per gallon of biodiesel.
[a] Base case; [b] Aggressive case; [c] Max case

- Immobilized microalgae culture

Suspended algae growth is the most common practice under consideration for algal biofuel production due to the improved economics of algae cultivation. However, separating the suspended algae culture from water in the harvesting stage becomes energy and cost intensive due to the difficulty in concentrating the suspended algae culture. Thus, immobilization of microalgae has been proposed to ease separation (Hoffmann, 1998). The immobilized microalgae cultures facilitate algal biomass recovery and hence reduce water losses during the harvesting process. Mallick (2002) identified six processes for immobilizing algae strains: covalent coupling, affinity immobilization, adsorption, confinement in liquid-liquid emulsion, capture behind semipermeable membrane, and entrapment. Ozkan et al. (2012) reviewed existing studies on immobilized algae production systems. The authors indicated that the lipid productivity and growth rate of the immobilized growth systems were not consistent when compared to suspended algae cultivation systems.

- Co-location with WWTP

Using algae as a treatment for wastewater has been previously investigated (Hoffmann, 1998). More recently, numerous studies have been published on using wastewater as growth media for algae to avoid extensive freshwater consumption during the algae cultivation process. One advantage of using wastewater is its higher nutrient content. Lundquist et al. (2010) estimated that using wastewater could save approximately 10% of the operational cost of algal biofuel production, mainly by reducing fertilizer use. Pittman et al. (2011) listed several factors that determined the success the of algae cultivation in wastewater, including operational parameters (e.g. pH, temperature), nutrient level, toxin concentration and biotic factors. In addition, algae species and starting density were also of key importance. The authors compared several sources of wastewater and concluded that municipal sewage wastewater and agricultural wastewater were preferred considering their high nutrient level, low toxin concentration and wide availability. Industrial wastewater, on the other hand, typically contains lower nutrient levels and higher levels of toxins and thus would not be as suitable for algae growth. Strum et al. (2011) investigated algae growth in open ponds with wastewater from a local wastewater treatment plant. The results showed that algal biomass productivity ranged from 0.78 to 15.9 g dry weight per m^2 per day over the course of the six month experiment. The analysis of the algal oil profile and its resultant biodiesel indicated that algae produced under such a system could be used as an alternative to oil seed crops for biodiesel production. The removal of 19% dissolved nitrogen and 43% of dissolved phosphorus were an additional benefit to the environment realized by this production method.

Beal et al. (2012) performed research to assess the energy return on investment (EROI) for integrating algae biodiesel production with wastewater treatment. The results indicated that an additional 5.5 kJ of energy could be produced or saved for each liter of processed wastewater through an integrated algae biodiesel production system, and the EROI was increased to 1.44 in this case as compared with 0.42 for a separate, stand-alone biodiesel production system. Zhou *et al*. (2011) isolated 60 algae-like microorganisms for algal biomass cultivation in concentrated municipal wastewater (CMW). The CMW had high total suspended solid (TSS) concentration and turbidity, allowing less light transmission for algae growth. 17 out of 60 strains survived in the CMW, among which 60% were *Chlorella* species. The total algal oil concentration (wt%) after a six-day cultivation period ranged from 17.41% to 33.53%.

- Reactor design

Considering the evaporation loss in open pond systems, the use of a photobioreactor (PBR) is an option to reduce the water consumption during algae cultivation. However, a crucial obstacle associated with PBR is difficulty in oxygen removal. Oxygen is the product of photosynthesis from algae culturing and it starts to prohibit the photosynthesis when its concentration is beyond air saturation (Carvalho et al., 2006). Additionally, to overcome the overheating issue in PBR, cooling water spray may be necessary and the water consumption associated can be huge (Pate, 2008). Another option of reactor design is to utilize algal biofilms. Algal biofilm formation initiates when algae cells attach to the growth surface. After initial attachment, algae starts to secrete extracellular polymeric substances (EPS) to strengthen the attachment. Finally, the biofilm develops into a mature structure (Qureshi et al., 2005). Algal biofilm is expected to provide a similar advantage of lower water loss as with immobilized algae cultures since harvesting can be realized by scrubbing algae biomass from the growth surface. Ozkan et al. (2012) introduced the application of a biofilm photoreactor for algae cultivation to lower water and energy consumptions. The photoreactor was composed of a biofilm growth surface, a nutrient medium recirculation system and an illumination system. The nutrient medium was delivered to the algae growth surface by dripping nozzles and at the end of the surface the nutrient overflow would be collected and re-circulated to the dripping nozzles. Harvesting was realized by mechanically scraping the thickened algae biomass with a squeegee. The process provided an algae mass production rate of 0.71 g per m^2 per day, and the total lipid content was 26.8% by dry weight. More importantly, the reduction in water required was approximately 45% in volume.

- *Harvesting and lipid extraction*

Unlike the conventional biodiesel process, feasible technology is still under investigation for harvesting algae from water and extracting the algae oil for biodiesel production. Many companies are developing various technologies, and details can be found in the Appendix to this chapter.

The following studies illustrate the potential to achieve a "water-efficient" harvesting or extraction process. Wet lipid extraction methods eliminate algae harvesting and dewatering steps, and thereby reduce energy consumption and water loss. The development of wet extraction technology is deemed as a critical step for the algal biofuel industry to move towards commercialization (Sills *et al*., 2013). Sathish and Sims (2012) employed *in-situ* hydrolysis of lipids in algae, centrifuge separation and recovery of lipids by hexane for biodiesel production. The process was able to extract 79% of the total transesterifiable lipids from a mixed-culture algae with 84% moisture. Teixeira (2012) used a combination of dissolution and hydrolysis of cell walls for algae extraction. It was found that at 100 to 140 °C, most of the algal cell walls were completely dissolved and lipid extraction could be achieved within 50 minutes. Cerff et al. (2012) performed a screening study on magnetic separation of both fresh and marine algae species. The results showed that over 95% separation efficiencies could be achieved, and complete algae removal could be attained in approximately five minutes in a high gradient magnetic filter system under continuous flow conditions. Levine et al. (2010) developed a two-step, catalyst-free process that extracted algal oil and converted it into biodiesel. Subcritical water was applied to hydrolyze the intracellular lipids and to agglomerate the cells into solids that retained fatty-acid rich lipids. In the second step, the solids underwent *in-situ* conversion by ethanol under supercritical conditions. Patil et al. (2011) studied the *in-situ* conversion of lipids in wet algae biomass (with 90% water) into biodiesel in a one-step process. The lipids were transesterified with supercritical methanol under 225°C for 25 minutes with an optimum ratio for wet algae and methanol (wt./vol.) of 1:9.

- *Resource demand*

As discussed previously, water will be a vital resource for algal biodiesel production. Site selection will be crucial to the success of an algal biodiesel plant and careful consideration must be given to the availability of water resources (especially freshwater) and access to sunlight radiation and carbon sources. Yang et al. (2011) discussed the impact of site selection on water consumption for algae growth. Considering the tradeoff between solar irradiation and evaporative water loss, their spatial analysis revealed that the water footprint of algae-derived biodiesel decreased from north to south with a roughly-defined boundary from the northern border of California to the northern border of New York. On the northern side of this boundary, the water footprint was estimated to be approximately 1,500 kg water/kg biodiesel, while in the southern side the value became progressively smaller. On the other hand, the water footprint also demonstrated a trend of decreasing from west to east. Similarly, Wigmosta et al. (2011) pointed out several preferred locations for microalgae growth in terms of reducing water loss that included the Gulf Coast region, most of the eastern seaboard and areas adjacent to the Great Lakes. It was also noted that the optimization of site selection could lead to a reduction of water consumption as large as 75%. Subhadra (2011) analyzed current water usage associated with biofuel production in Southwestern U.S. The authors confirmed that this region was potentially an optimum area for algal biodiesel production considering the availability of various resources. But the authors also indicated that sustainable water management policies would be imperative to protect regional water resources and hydrologic patterns while developing algal biodiesel in this region.

- *Data gaps*

- Data gaps with respect to studying the impact of algal biodiesel on freshwater consumption

As proposed by the NAP report (NRC, 2012), a more accurate model to estimate evaporation losses from algal biodiesel production processes is needed. Guieysse et al. (2013) compared nine evaporation models from existing literature and discovered significant uncertainty regarding evaporation predictions. Currently, some studies use pan evaporation (Harto et al. 2010; Yang et al. 2011), which is not a very good surrogate for actual open-pond evaporation, to approximate the evaporation behavior of algae raceways. Also, modeling of the water balance, salt buildup and its management is of particular importance for future research. In addition, when wastewater is used to minimize freshwater consumption, knowledge of water quality and its influence on algae growth and an understanding of the resultant processing steps that may be necessary (e.g., bioconcentration of heavy metals in algae may affect the further processing of algae biomass) is another area possibly needing additional research. Information about water resource distribution (both survey and ground water) needs updating so that analyses of sustainable water withdraws can be performed with higher precision.

There is potential for algae cultivation to have negative influences on water quality from the release of algae culture broth into surface water bodies and/or ground water aquifers. The release could occur as a result of overflow caused by extreme weather events, improper operation or noncompliant discharges, or due to defects in the design, construction and maintenance of open ponds. Considering the nutrients in the algae growth broth, the release may lead to eutrophication in surface water bodies. In addition, many algae species can bioconcentrate heavy metals if flue gases are used as the CO_2 source for algae growth (O'Dowd et al., 2006). If wastewater is used, waterborne toxicants contained in the released algae culture broth may pose a risk to both surface and ground water sources, and threaten drinking water quality.

In addition to the algae growth stage, the harvesting and extraction stage may also result in negative impacts on water quality through incidental release or spillage of the culture broth. Wastewater generated during the algal biodiesel production stage, on the other hand, is expected to have a similar impact on water quality as transesterification of other lipid feedstocks.

- Data gaps regarding the impact of algal biodiesel on the water quality of surface and ground water resources:

To assess the impact of algae biodiesel production on the quality of surface and ground water resources, an initial step would be to develop a representative database of factors such as the typical nutrient load and the quality of the non-freshwater used for algae growth. Additionally, background information about the region of interest would be necessary for impact analysis. Examples include the current loading and concentrations of nitrogen and phosphorus-containing compounds, herbicide, heavy metals and salinity in surface and ground water sources.

8.3.1.6 Drought-tolerant plants

New and improved crop species, such as the ones that can use less water, marginal lands, etc., may also help reduce the water intensity for biodiesel production. In order to reduce water consumption, several drought-resistant feedstocks have been proposed, including jatropha, camelina, and pennycress.

Jatropha is a genus of a long history and belongs to the *Euphorbiaceae* family. Jatropha is known for its high adaptability to a wide range of soil quality and irrigation/precipitation conditions (Makkar and Becker, 2009). It has been reported by several studies to be more capable of withstanding drought stress than other lipid crops (Niu et al., 2012; Rao et al., 2012; Ye et al., 2009). According to Gardner et al. (2012), the oil productivity of jatropha is approximately 194 gallons per acre, more than four times as much as that of soybeans. One downside of jatropha oil is that it usually contains high FFA levels, which require acid esterification as a pretreatment (Tiwari et al., 2007). Several pilot studies have been performed to investigate the feasibility of jatropha cultivation and the outcomes were not as promising as expected. It was found that if jatropha is cultivated in the marginal areas, the yield is compromised (Louma, 2009). However, growth of jatropha is not likely to be feasible in regions above the 30-degree latitude in North America (U.S. EPA, 2010).

Camelina belongs to the *Brassicaceae* family. Similar to jatropha, camelina can survive in drought and semiarid conditions, and requires less fertilizer and pesticide application (Moser, 2010). Camelina has an oil productivity of approximately 60 gallons per acre, slightly higher than that of soybeans (Gardener et al., 2012). In addition to the oil, camelina meal can be used as animal feed (Ehrensing and Guy, 2008). Unlike jatropha oil, camelina oil generally contains a very low level of FFA (Sanford et al., 2009).

Pennycress is also a member of the *Brassicaceae* family. Pennycress is able to tolerate low temperatures, minimal fertilizer inputs and limited water supply. Moreover, its low temperature tolerance makes it possible to grow pennycress during winter when arable lands are typically fallow. Analysis shows that pennycress contains around 30 wt% oil content and the field yield is expected to be approximately 100 gallons per acre (USDA-ARS, 2006; Voegele, 2010).

Other waste oil containing materials can also become biodiesel feedstocks, especially at the community scale, such as the fats, oils and greases (FOG) from food services and the sewer system. An EPA study indicated that FOG in the sewer system is the number one cause of sewer overflows and it is mainly landfilled (U.S. EPA, 2007). The advantages include low costs and cost savings from landfill tipping fees. The difficulties usually lie in the quantity, waste collection, and, most challenging of all, oil extraction from these feedstocks.

8.3.2 Biodiesel and bio-based diesel fuel technology development

Along with the rapid expansion of the biodiesel industry in the U.S., there has also been active research and development in search of new feedstocks, technology innovation and further process improvement.

8.3.2.1 *Biodiesel dry wash*

As a purification process step, biodiesel water washing has several advantages. It is easy to operate, has a relatively low cost, and it is effective in removing glycerin and alkaline catalysts. Its disadvantages include emulsion formation, the need for post-washing heating (to remove moisture content), a long process time, water consumption and wastewater generation. Emulsion not only prolongs the purification time but also leads to the loss of biodiesel yield. More importantly, wet washing consumes considerable amounts of water and generates wastewater that usually requires pretreatment or discharge permitting. With increased concerns regarding biodiesel sustainability and regional water stress, dry wash technologies have been increasingly adopted by biodiesel producers, especially for newly constructed biodiesel processing plants. Major dry wash technologies include using adsorbents and ion-exchange resins. A typical adsorbent used by the biodiesel industry is a synthetic magnesium silicate. This adsorbent is able to adsorb polar compounds such as methanol, glycerin, and FFAs (Bryan, 2005). Use of ion-exchange resins, such as Purolite® PD 206, the Na^+ and K^+ from the sodium hydroxide and/or potassium hydroxide catalysts, is exchanged with H^+ from a reactive group on the surface of the resin beads to break down soaps (Biodiesel TechNotes, 2010).

The advantages of dry washing processes include reduced purification time, waterless processing, and increased final biodiesel recovery (Sims, 2011). The disadvantages of dry washing methods include sorbent cost, increased metal concentrations in biodiesel (such as Na, K and even Ca) and waste disposal issues as most of the sorbents are not regenerated.

For adsorbents such as magnesium silicates, one concern is the increased purification cost since it cannot be regenerated. Also, it has been found that some fine silicate particles can remain in the purified biodiesel, potentially causing engine deposit or wear issues. For ion-exchange resins, the elevated acid value after purification is an inherent problem, so the FFA level should be relatively low before ion-exchange resin purification can be applied (Smith, 2012).

Some biodiesel producers are developing sorbents (proprietary research and development) from waste materials, such as saw dust, wood chips and waste coffee grounds. These materials resemble activated carbon and can be burned as boiler fuel (i.e., for steam generation or evaporative distillation) after use.

8.3.2.2 *Heterogeneous catalysis*

Homogeneous catalytic transesterification is the standard technology in the biodiesel industry, with alkaline catalysts such as $NaOCH_3$, NaOH and KOH. The advantages are the use of low-cost catalysts, high reaction rates and high yield reactions. With increased biodiesel production and more stringent environmental regulations, the disadvantages are that the catalysts are non-recyclable, they are hard to separate from biodiesel, and often require neutralization during biodiesel processing. Therefore, heterogeneous catalysis using solid catalysts is under active research.

A variety of materials have been tested as catalysts: (1) alkaline earth metal oxides and derivatives such as MgO, CaO, SrO, etc., (2) carbohydrates such as sucrose and cellulose, (3) alkaline inserted complexes and zeolites, (4) transition metal oxides and derivatives, (5) mixed metal oxides and derivatives, (6) hydrotalcite metal oxides, (7) cation-exchange resin, (8) sulfated oxides, and (9) biocatalysts (Singh Chouhan and Sarma, 2011).

Heterogeneous catalysis of FAME eliminates the use of potentially hazardous acid and alkali materials, which also reduces the efforts for subsequent purification. The heterogeneous process is usually developed to be more effective with low quality feedstocks that contain larger amounts of free fatty acids (FFA). For example, the current process of high FFA feedstocks uses H_2SO_4 esterification and excess methanol. Additional energy and material are required for excessive methanol recovery and neutralization of H_2SO_4. The heterogeneous process is developed to combine the esterification and transesterification in a single step and thereby has the potential to reduce methanol use. Additionally, heterogeneous catalysts are reusable. Currently the downsides of the heterogeneous process includes high energy input (e.g., high temperature and pressure). Only a few biodiesel producers use heterogeneous catalysis since it requires significantly different process equipment from most existing biodiesel production operations. McNeff et al. (2008) developed a heterogeneous catalysis process, called Mcgyan®, which has been applied by the Ever Cat Fuels™, LLC biodiesel manufacturer (3 M-gallons per year capacity). To date, very few applications have been found in the biodiesel industry, and some resistance in adopting has been observed.

8.4 Summary

The current biodiesel industry still relies heavily on oil crops like soybeans. The water consumption associated with biodiesel production from oil crops mainly stems from irrigation, with minor consumptions from oil processing and biodiesel manufacturing stages. The results suggest that on average irrigation accounts for 61.78 gallons (gal) of water for a gallon of soybean biodiesel, while soybean processing (0.17 gal/gal) and biodiesel production (0.31 gal/gal) stages consume much less. The total water consumption intensity for the entire biodiesel production process was found in this analysis to be 62.26 gal/gal, which is considerably lower than reported in previous literature. However, water consumption from the three stages varies significantly from state to state, which warrants state-level water consumption analyses in order to improve decision making with respect to water resource management.

The need to develop lower cost feedstocks will remain critical for the biodiesel industry. The need to understand their impact on water resources is also critical. Distiller grains are expected to become a major biodiesel feedstock (U.S. EPA, 2010). Renewable diesel has the potential to become a significantly important technology since it is a direct replacement for diesel and jet fuel petroleum distillate fuels. If large-scale production of renewable diesel is to happen in the future, its impact on water resources should also be and further analysis should be conducted to characterize water used in renewable diesel fuel manufacturing and its upstream feedstock production.

Production of biodiesel from algae has the potential to reduce competition for agricultural resources between biofuel production and food crop production, and to reduce the cost of lipids used for transesterification to FAME. Important advances have been made in developing more sustainable algal lipid production processes through the use of wastewater and brackish water for algal growth. With technology improvements, low quality lipid feedstocks, especially feedstocks from waste such as the trap grease from restaurants, sewer pipeline, and other lipid containing wastes, will be increasingly used for biodiesel production. These serve the dual benefits of waste reduction and renewable fuel production. Limitations of these feedstocks include their limited quantity (i.e., they will contribute to only a small fraction of the biodiesel supply) and that they will require pretreatment to extract the oil fractions useable for FAME production. A better understanding of the life cycle water needs for waste feedstocks will be necessary. Similarly, a comprehensive evaluation of the sustainability matrix of any crop-based feedstocks would also be necessary before large scale use of any of the new crop-based feedstocks for FAME biodiesel or renewable diesel fuel production.

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8.6 Appendix

8.6.1 Sample calculation for irrigation water consumption and normalized water intensity for Ohio

8.6.1.1 Irrigation water consumption for Ohio (W_{1OH})

An example of calculation procedures for W_1 and N_1 for Ohio is provided below. Following the same principle, results can be calculated for the state-level irrigation water consumption for soybean growth by using state-specific data from USDA reports (USDA, 2007, 2008). According to Table 28 in 2008 Farm and Ranch Irrigation Survey (USDA, 2008), the total irrigated area for soybean through primary water distribution methods is 1,056 acres in Ohio and the average acre-feet applied per acre is 3.2. Therefore, the total volume of irrigation water for soybean in 2007 is:

$$V_T = 1056 \times 3.2 = 3379.2 \text{ acre-feet}$$

Since one acre-foot equals 325,851 gallons:

$$V_{Tj} = 3379.2 \times 325851 = 1.10 \times 10^9 \text{gallons of water}$$

Mass-based allocation:

According to the assumptions above, 19.5% (F_{soy}) of soybean was oil, about 17% (F_{use}) of the soybean oil in 2007 was used for biodiesel production (Centrec Consulting Group, 2013) and 89% (F_{BioD}) oil was eventually converted into biodiesel (USB, 2013).

So for the calculation of W_1:

$$W_{1OH} = V_{Tj} \times F_{soy} \times F_{use} \times F_{BioD}$$

$$= \frac{1.10 \times 10^9 \times 19.5\% \times 17\% \times 89\%}{1000000}$$

$$= 12.25 \text{ million gallons of water (MMgpy)}$$

8.6.1.2 Normalized irrigation water intensity for Ohio (N_{1OH})

Assume one bushel soybean weighs about 60 pounds and the density of soybean biodiesel is 7.4 lb/gallon. According to Table 28 in 2008 Farm and Ranch Irrigation Survey (USDA, 2008), total harvested soybeans in bushel are 191,559,567, the normalized irrigation water consumption per bushel of soybean is:

$$R_1 = 1.10 \times \frac{10^9}{191559567}$$

$$= 5.75 \text{ gallons of water / bushel soybean}$$

Appendix Table 8.1 Biodiesel plant capacity in each state

State	Plant Capacity (MMgpy)	State	Plant Capacity (MMgpy)
Alabama	13.3	Nebraska	5
Alaska	0.25	Nevada	1
Arizona	48	New Hampshire	5.75
Arkansas	119	New Jersey	90
California	78.465	New Mexico	1.5
Colorado	0	New York	25.25
Connecticut	3.8	North Carolina	21.6
Delaware	5	North Dakota	88
Florida	39	Ohio	132
Georgia	63.5	Oklahoma	36
Hawaii	4.5	Oregon	17.94
Idaho	5.5	Pennsylvania	111.26
Illinois	173.6	Rhode Island	2
Indiana	121	South Carolina	90.3
Iowa	304.5	South Dakota	7
Kansas	3.9	Tennessee	53
Kentucky	63	Texas	577.25
Louisiana	19.2	Utah	10
Maine	1.5	Vermont	0
Maryland	7.5	Virginia	16
Massachusetts	0.5	Washington	113
Michigan	49.75	West Virginia	3
Minnesota	66		
Mississippi	115.5		
Missouri	183.5		
Montana	0		

So, the allocated water consumption for biodiesel from one bushel is:

$$R_2 = 5.75 \times 19.5\% \times 17\% \times 89\% = 0.17 \ gallons \ water \,/\, bushel \ soybean$$

Finally, the irrigation water consumption based on every single gallon of biodiesel is:

$$N_{1OH} = 0.71\ gallons\ water\ /\ gallon\ soybean\ biodiesel$$

8.6.1.3 Allocation factor for soybean growth stage

$$F_1 = F_{soy} \times F_{use} \times F_{BioD} = 19.5\% \times 17\% \times 89\% = 0.03$$

8.6.2 Calculation of normalized water consumption and sample calculation for water consumption in the soybean crushing and processing stage for Ohio

8.6.2.1 Normalized water consumption (N_2) in the soybean crushing and processing stage

According to the life cycle report by United Soybean Board (2010), the water consumption during soybean processing and refining stage is: 1,167 and 65.9 kg/1,000 kg soybean oil for the two steps. Below is the conversion of water consumption occurred in this stage into normalized value based on one gallon of biodiesel.

$$N_2 = \frac{(1{,}164 + 65.9)kg\ H_2O}{1{,}000kg\ soybean\ oil} \times \frac{1\ m^3}{1{,}000\ kg\ H_2O} \times \frac{900\ kg\ soybean\ oil}{1\ m^3} \times F_{use} \times F_{BioD} = 0.17\ gal/gal$$

As stated in the main text, N_2 is assumed to be uniformly applicable to all the states in this study.

8.6.2.2 Water consumption during soybean crushing and processing for Ohio (W_{2OH})

Also for the total water consumption in this stage (W_2), the calculation is performed based on the same allocation principles. Below is the sample calculation for the State of Ohio.

From Table 28 in 2008 Farm and Ranch Irrigation Survey (USDA, 2008), the harvested soybean in 2007 is 191,559,567 bushels, which translates into $5.2 \times 10^9\ kg$. By applying the consumption factor of 1,229.9 kg water /1000 kg oil (Appendix Table 8.2), the total water consumption before allocation is $6.4 \times 10^9\ kg$. Following the same allocation procedure, the total water consumption during soybean crushing and processing stage for Ohio is 49.95 MMgy.

$$W_{2OH} = 191{,}559{,}567 \times \frac{60\ lb\ soybean}{bushel} \times F_{soy} \times \frac{0.454\ kg}{lb} \times \frac{1}{1{,}000} \times \frac{(1{,}164 + 65.9)kg\ H_2O}{1{,}000\ kg\ soybean\ oil} \times F_{use} \times F_{BioD} \times \frac{1\ gal\ H_2O}{3.78\ kg\ H_2O} \times \frac{1\ MMgy}{1{,}000{,}000\ gal/yr} = 49.95\ MMgpy$$

8.6.2.3 Allocation factor for soybean crushing & processing stage

$$F_2 = F_{use} \times F_{BioD} = 17\% \times 89\% = 0.15$$

8.6.3 Sample calculation for normalized and total water consumption for biodiesel manufacturing in Ohio

8.6.3.1 Normalized water consumption (N_3) in the biodiesel manufacturing stage

Three scenarios are proposed in this study to account for water consumption from different purification methods (water/day wash) and process operations (cooling tower make-up). Assuming water wash and dry wash both account for 50% of current biodiesel purification technology, an averaged value from the data representing different scenarios is obtained through the following equation:

$$N_3 = \left\{\frac{1}{2} \times \left[\left(Water\ Wash_{upper} + Cooling\ Tower_{water}\right) + \left(Water\ Wash_{lower} + Cooling\ Tower_{water}\right)\right] + Cooling\ Tower_{dry}\right\} \times \frac{1}{2} = 0.31\ gal/gal$$

Where: $Water\ Wash_{upper}$ and $Water\ Wash_{lower}$ are the washing water consumptions (gal/gal) from upper and lower scenarios; $Cooling\ Tower_{water}$ and $Cooling\ Tower_{dry}$ are the volumes of cooling tower make-up water (gal/gal) for water wash and dry wash scenarios.

8.6.3.2 Total water consumption (W_{3OH}) in biodiesel manufacturing stage for Ohio

W_3 is calculated by following equation:

$$W_3 = N_3 \times Total\ Biodiesel\ Plant\ Capacity$$

For a specific state, such as Ohio, the product of N_3 (0.31) and total biodiesel plant capacity (132 MMgpy) yield a W_{3OH} of 40.92 MMgy.

8.6.4 Water-saving technologies developed in the algae industry

- Reactor design

A commercial application of the biofilm reactor is the "Algal Turf Scrubber" by Hydromentia (http://www.hydromentia.com/). A plastic mesh is used as the growth substrate for filamentous algae and the mature biofilm is scraped by a scrubber to harvest algae biomass.

- Harvesting and lipid extraction

Algaeventure Systems, Inc. (http://algaevs.com/) received $5.9 million from U.S. Department of Energy's Advanced Research Projects Agency-Energy (ARPA-E) and developed the solid liquid separation (SLS) system for the harvesting of algae, which significantly lowers the cost of separation compared with centrifuge separation systems. Evodos (www.evodos.eu) developed a low-cost, high-performance centrifuge system that could reach over 95% of the separation efficiency and minimize the extracellular water attached to the algae biomass paste. Aurora Algae Inc. (http://www.aurorainc.com/) developed a unique process that removed protein and carbohydrates from the algae growing media and left behind the water/lipid mixture that could be easily separated. AER Sustainable Energy (www.aer-bio.com) developed an enzymatic hydrolysis process that lysed cell walls of algae. United Technologies Inc. (www.uniteltech.com) developed a hydrolysis technology that focused on producing fatty acids from algae biomass to avoid the water removal and lipid extraction steps. Diversified Technologies Inc.

(www.divtecs.com) utilized pulsed electric field technology to rupture the cell wall of the algae biomass to release the lipids and hence facilitate the oil extraction process. Phycal's (www.phycal.com) proprietary non-destructive oil extraction technology continuously recovers oil from algal cells. The process mixes the algae culture with a lipid extraction solvent and uses sonication for separation. OriginOil (www.originoil.com) developed an electro-assisted harvesting device that coagulates and floats the algae cultures for skimming collection. New Oil Resources (www.newoilresources.com) employed a one-step process that converts biomass into fuels. The technology uses water at high temperature and pressure to de-polymerize the biomass into smaller compounds and allow recovery.

Appendix Table 8.2 Water consumption data in biodiesel wash collected from biodiesel manufacturers

Data Sources	Feedstock	Washing Water (gal/gal)	Production Capacity (Million Gallons per year)
Company 1	Multi-feedstock	0.1	3
Company 2	Animal Fats	0.0125~0.015	1.25
Company 3	Waste Cooking Oil	0.84	4.5
Company 4	Multi-feedstock	0.25~0.375	12
Company 5	Multi-feedstock	0.09~0.1	180
Company 6	Waste Cooking Oil Animal Fats	0.06	1.5

* Company names omitted at their requests.

The variation in the data reported by these companies can be attributed to a number of factors, including water reuse practices, washing water properties (e.g., acidic/warm), plant size, as well as water availability and pricing.

Appendix Table 8.3 Water consumption in cooling tower make-up

Data Sources	Feedstock	Purification method	gal water/ gal biodiesel
Company 7	Virgin oil	Dry wash (silicate)	0.12-0.15
	Virgin oil	Water wash with recycle	0.19-0.21
	Waste cooking oil	Dry wash (silicate)	0.27-0.3
	Waste cooking oil	Water wash with recycle	0.33-0.36
Company 8	Multi-feedstock	Dry wash (silicate)	0.03-0.05

Data from Company 7 indicates that using low quality feedstock corresponds to higher make-up water, which may be due to the need to recover an excessive amount of methanol (e.g., for the esterification reaction). Company 8 has much smaller make-up water consumption, which is achieved by integrating other cooling approaches such as an air chiller. The biodiesel production capacities of these two companies are 29 MMgpy and 14 MMgpy respectively.

Appendix Table 8.4 Summary of water-stressed states from literature

Studies	Criteria	Water stressed areas
EPRI report [1]	Water Supply Sustainability Index	AL, AZ, CA, FL, GA, ID, LA, NM, NV, TX, WA
Hurd et al. [2]	Level of development, natural variability, dryness ratio, groundwater depletion, industrial water use flexibility and institutional flexibility	AZ, CA, CO, KS, NM, NV, TX, UT
Scown et al. [3]	Palmer Drought Index	Southwestern US
Yang [4]	Available precipitation	AZ, CA, CO, FL, GA, NV

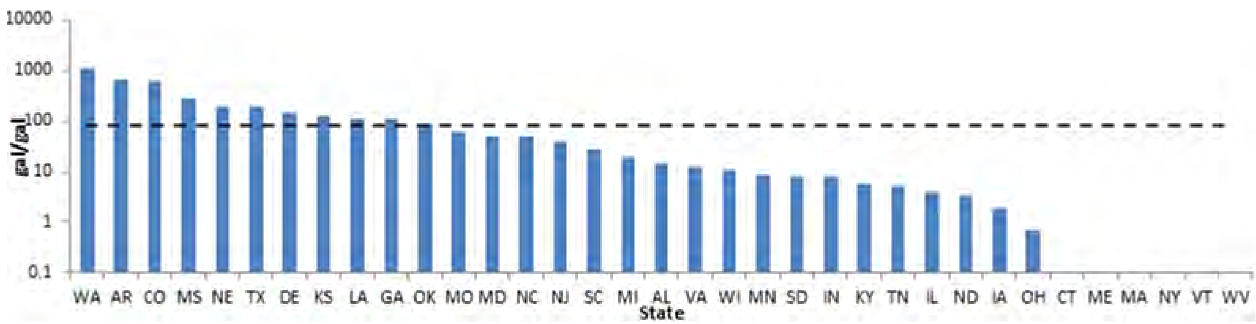
Note: [1] EPRI, 2003; [2] Hurd et al., 1999; [3] Scown et al., 2011; [4] Yang, 2010

Appendix Table 8.5 Key assumptions and parameters of the studies

	O'Connor[1]	King and Webber[2]	Harto *et al.*[3]	Mulder *et al.*[4]	This study
Parameters and Assumptions					
Irrigation water loss %	100%	79.7%	100%	100%	100%
% soybean irrigated	8.2%	either 100% or 0%	4%	NA	Overall: 8.2%
Energy-water in irrigation	No	0.158 gal/gal	No	No	No
Fertilizer water use	No	No	11 gal/gal	No	No
Parameters and Assumptions					
Normalized irrigation consumption (N_1)	79 gal/gal	200 gal/gal	119.5 gal/gal	716.35 gal/gal	61.78 gal/gal
Normalized consumption during soybean crushing & processing (N_2)	NA	0.009 gal/gal	No	No	0.17 gal/gal
Soybean oil-to-biodiesel (N_3)	NA	0.158 gal/gal	0.5gal/gal	3.63gal/gal	0.31 gal/gal
N_{tot} (gal/gal)	79	200.32	131	719.98	62.26

Note: [1]O'Connor, 2010; [2]King and Webber, 2008; [3]Harto et al., 2010; [4]Mulder et al., 2010.

Appendix Figure 8.1 Irrigation water use at state level for soybean growth (W1, million gallons per year). Note that 35 out of 50 states have data.



Appendix Figure 8.2 The irrigation water intensity for soybean growth by state (N1, gallon water per gallon biodiesel).

8.6.5 Appendix 8 References

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9 Impacts of Electric Generation on Water Resources: Regional Assessment and Adaptation

Patcha Huntrai and Timothy C. Keener[i]

9.1 Introduction

Thermoelectric power plants in the southwest U.S. are most likely to face challenges regarding water withdrawal and consumption due to the arid climate. The impacts of thermoelectric water withdrawals are exacerbated by regional population migration. The southwest and southeast regions of the U.S. were selected for a sustainable future projection case study within this report. Southwestern states in particular (e.g., Arizona, California, New Mexico, Nevada, Texas and Utah) face severe water-stressed conditions (Yates et al. 2013a; Yates et al. 2013b). Consumptive water (i.e., water that is effectively removed from the system and not available for other uses) is an important consideration for water-scarce regions, and is particularly relevant in future energy resource development (NREL, 2012). Physical and regulatory compliance limitations associated with high water withdrawals can lead to water-related power plant curtailments and shut downs even in water-rich regions, such as the 2007 southeast U.S. drought (NETL, 2009).

As discussed in further detail within Chapters 2 and 4, the electric power sector is responsible for a significant fraction of total water withdrawals in the U.S. For example, thermoelectric power plant operations are estimated to be responsible for 36 to 41 percent of total freshwater withdrawals (Meldrum, 2013b). Regulatory changes, policy changes, and shifts in the dispatch of electricity by plant type are expected to significantly impact management of local, regional, and national water resources (NREL, 2012).

9.2 Regional Integrated Water-Energy Resource Management

There is geographical variation in the relative importance of water withdrawals and consumption due to regional water resource availability, environmental considerations and water allocation requirements (NREL, 2012). Due to the uncertainty of climate change and the increasing demand for water to cool thermoelectric generation capacity, there will be substantial competition for water in many regions. Water-stressed regions are of particular concern as water withdrawal rates are greater than 60 percent of mean annual runoff (NREL, 2012; Raskin et al., 1997; Waggoner et al., 1990). Evaluating the water usage of all electricity-generating technologies will provide critical information necessary for decision makers to develop strategies to relieve critical stresses from water resources.

The most common forms of electric generation in the U.S. such as coal, natural gas, and nuclear power are highly water-consumptive. In contrast, the least water-consumptive forms of generation are those of emerging technologies such as wind and solar photovoltaic technologies.

Figure 9.1 shows the water intensity of electricity generation (represented in gallons per megawatt). These water intensities demonstrate the consumptive demand for cooling systems,

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which vary considerably depending on the fuel source and the type of cooling technology used. Researchers have found that many low-carbon-intensity, renewable sources of electric generation such as wind, solar photovoltaic (PV), geothermal energy, and some types of concentrating solar power (CSP), consume far less amounts of water when compared to non-renewable sources such as fossil-fuel thermoelectric generation (WRA, 2008).

Photovoltaic and wind generation require far less water per unit energy produced than do conventional thermoelectric generation. In water-deficient regions, such generation sources with low water requirements may be in increasing demand. Another example of renewable electric generation is a wet cooling CSP plant that uses water to condense steam downstream of a steam turbine. Even though wet cooling CSP designs consume a great amount of water compared to dry cooling CSP, the wet cooling CSP may be required in arid climates because a dry solar CSP plant may overheat due to an insufficient temperature differential in the heat exchanger. Overheating of a CSP plant reduces efficiency, thus decreasing electricity output (WRA, 2008).

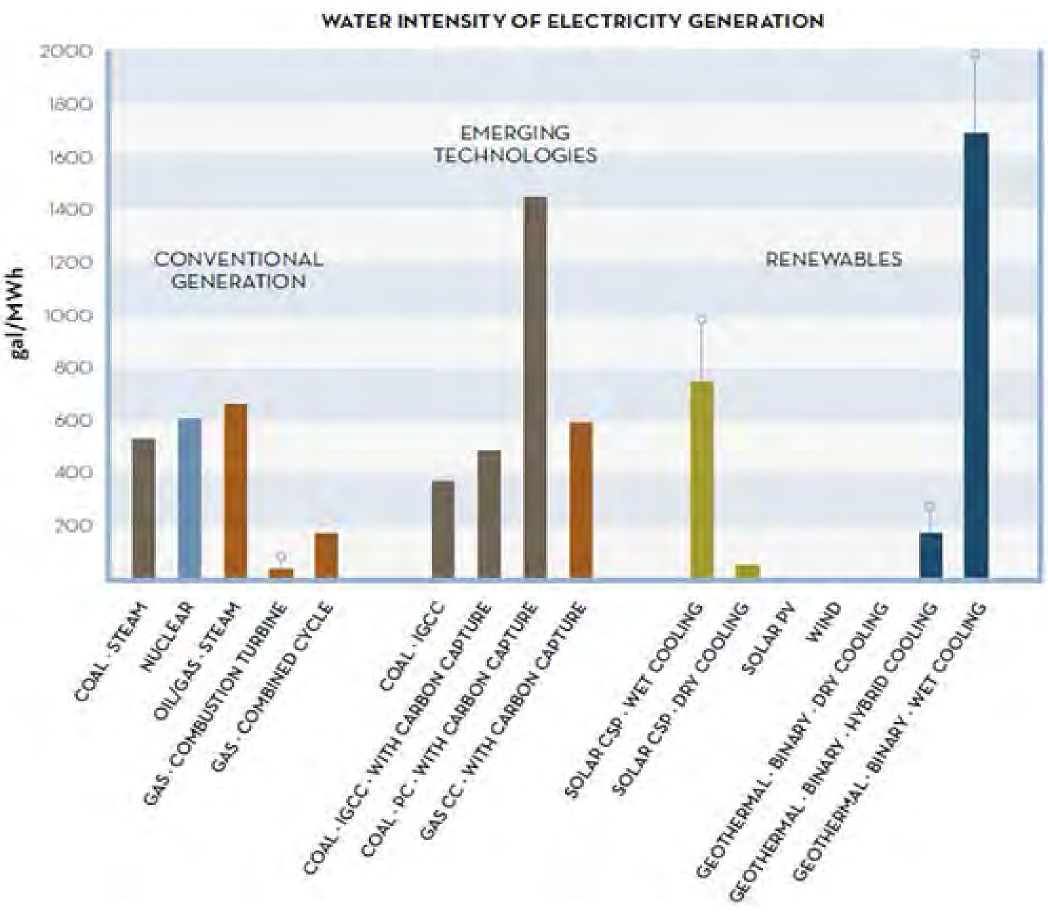

Figure 9.1 Typical rate of water consumption for electricity generation (consumptive use). Error bars are included for technologies for which multiple data points were available. Adopted from Western Resource Advocates (2008).

The life cycle water use research by Meldrum et al. (2013a) estimates water withdrawal and water consumption for selected electricity-generating technologies. These water use estimates were classified as either "water withdrawal" or "water consumption." Water withdrawal is defined as the water diverted from a water source for use, and water consumption is defined as the portion of withdrawn water that is not returned to the immediate water resource after use (Meldrum *et al.* 2013b). Water use factors were developed for each of the three main life cycle stages: the fuel cycle, the power plant life cycle, and power plant operation. These three stages can be seen in Tables 9.1 to 9.3. The fuel cycle includes fuel extraction, fuel processing, and fuel transportation. The power plant life cycle includes component manufacturing, power plant construction and power plant decommissioning. The life cycle water usage factors are primarily influenced by the cooling water demands for thermoelectric generation. Of the renewable energy sources, two generation technologies (PV and wind) used the least amount of water across the life cycle. These two technologies only require water for occasional cleaning purposes (see Table 9.2 and Table 9.3). The life cycle water use for the different technologies varies based on the spatial and temporal requirements associated with the fuel cycle and the power plant life cycle. Because of this variability, the water consumption and water withdrawal for electricity generation should be considered separately across different life cycle stages (Meldrum *et al.* 2013b). Thus, the following stated water usage will be considered solely in the context of power plant operation, and more specifically, the cooling water process.

Table 9.1 Range of fuel cycle water consumption and withdrawal estimates for selected generation technologies and sub-categories

		Consumption (gal/MWh)			Withdrawal (gal/MWh)		
Generation Technology	**Sub-Category**	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**
Coal	Surface Mining	6.1	21.9	58.1	6.1	21.9	60.8
Coal	Underground Mining	16.9	55.5	229.9	16.9	58.1	229.9
Natural Gas	Conventional Gas	1.1	4.0	25.9	4.0	5.0	34.3
Natural Gas	Shale Gas	2.9	16.1	208.7	5.0	16.9	219.3
Nuclear	Centrifugal Enrichment	12.9	55.5	290.6	12.9	55.5	290.6
Nuclear	Diffusion Enrichment	42.3	87.2	317.0	60.8	140.0	422.7

Note: Adopted from Meldrum et al. (2013a,b).

Table 9.2 Range of power plant equipment water consumption and withdrawal estimates for selected generation technologies and sub-categories

	Consumption (gal/MWh)			Withdrawal (gal/MWh)		
Generation Technology	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**
Coal	< 0.5	1.1	25.1	< 0.5	1.1	11.9
Natural Gas	< 0.5	1.1	1.1	< 0.5	< 0.5	1.1
Nuclear	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5
CSP	79.3	158.5	169.1	97.8	161.2	169.1
Geothermal	2.1	2.1	2.1	< 0.5	2.9	10.0
PV (C-Si)	10.0	81.9	208.7	1.1	95.1	1611.6
PV(Other)	5.0	6.1	6.9	< 0.5	18.0	1400.3
Wind	< 0.5	1.1	9.0	13.00	25.9	81.9

Note: Adopted from Macknick et al. (2012).

Table 9.3 Power plant operations cycle water consumption and withdrawal estimates for selected generation technologies and sub-categories

		Consumption (gal/MWh)			Withdrawal (gal/MWh)		
Generation Technology	**Sub-Category**	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**
Coal: Pulverized Coal(sub-critical)	Cooling Tower	200.8	528.4	1294.6	449.1	660.5	1188.9
Coal: Integrated Gasification Combined Cycle	Cooling Tower	34.3	317.0	449.1	161.2	396.3	605.0
Natural Gas: Combined Cycle	Cooling Tower	47.6	208.7	290.6	150.6	251.0	766.2
Natural Gas: Combustion Turbine	No Cooling	50.2	50.2	343.5	422.7	422.7	422.7
Nuclear	Cooling Tower	581.2	713.3	898.3	792.6	1109.6	2589.2
CSP: Trough	Cooling Tower	554.8	898.3	1902.2	871.9	951.1	1109.6
CSP: Power Tower	Cooling Tower	739.8	819.0	871.9	739.8	739.8	739.8
Geothermal	Binary, Dry Cooling	264.2	290.6	634.1	264.2	290.6	634.1
PV	Flat Panel	1.1	6.1	25.9	1.1	6.1	25.9
Wind: On-shore	n/a	1.1	1.1	2.1	1.1	1.1	1.1

Note: Adopted from Meldrum et al. (2013a,b) and Macknick et al. (2012).

The location of a power plant also has a major impact on the technology and processes that are used for generating electricity and, therefore, has a direct impact on water consumption

Table 9.4 National electricity water crisis areas

Rank	County	Total Electricity in 2025 in (MW)	Population Growth 1995 to 2025 (per sq.mile)	Summer Water Deficit in 2025 (inches)	Metropolitan Area
1	Mecklenburg	17,950	1,528	28.72	Charlotte, NC
2	Lake	12,987	1,064	18.1	Chicago, IL
3	Will	27,399	806	16.67	Chicago, IL
4	Queens	11,613	8,056	12.68	New York, NY
5	Cobb	3,480	2,049	9.34	Atlanta, GA
6	Dallas	6,170	1,437	6.6	Dallas, TX
7	Coweta	6,180	510	5.56	Atlanta, GA
8	Denver	4,503	1925	4.98	Denver, CO
9	Montgomery	3,776	757	4.45	Washington, DC and Baltimore, MD
10	St. Charles	3,350	533	4.33	St. Louis, MO
11	Washington	3,203	632	4.2	St. Paul, MN
12	Bexar	9,222	555	2.98	San Antonio, TX
13	Calvert	12,938	533	2.92	Washington, DC and Baltimore, MD
14	Harris	4,462	1,179	2.4	Houston, TX
15	Tarrant	2,704	1,170	2.34	Dallas, TX
16	Multnomah	5,402	548	2.24	Portland, OR
17	Contra Costa	4,759	678	1.99	San Francisco, CA
18	Fort Bend	19,656	851	1.88	Houston, TX
19	Wake	5,967	1,266	1.65	Raleigh, NC
20	Suffolk	5,062	1,184	1.65	Boston, MA
21	Clark	20,148	642	1.52	Las Vegas, NV
22	Montgomery	2,871	647	1.52	Houston, TX

Note: Adapted directly from Sovacool and Sovacool (2009).

and withdrawal. Sovacool and Sovacool (2009) identified 22 National Electricity-Water Crisis Areas (shown in Table 9.4), and showed that there is likely to be a trade-off between the water needed to satisfy demands for drinking, agriculture and other uses in these areas and the water needed for new thermoelectric generation capacity. These metropolitan areas have a combined population growth of at least 500 people per square mile, a demand of at least 2,700 MW of electric capacity, and a projected summer water deficit of at least 1.52 inches by 2025 (See Table 9.4) (Sovacool and Sovacool, 2009). Their findings showed that ten of the National Electricity-Water Crisis Areas—Atlanta, Charlotte, Chicago, Denver, Houston, Las Vegas, New York, San

Francisco, St. Louis, and Washington, DC—plan to add a collective 149,892 MW of thermoelectric capacity by 2025 with the potential use of 29.41 trillion gallons of water per year for thermoelectric cooling (nearly 81 billion gallons of water per day) (Sovacool and Sovacool, 2009). A case study was conducted to follow the water and energy management of one of these ten National Electricity-Water Crisis Areas, Las Vegas.

9.2.1 Case study: Las Vegas

The Las Vegas metropolitan area is one of the ten national electricity-water crisis areas depicted in Table 9.4. Growing populations, including tourists and business visitors, have increased demand for electricity and water supplies. Water resources in the Las Vegas metropolitan area have been a concern due to the ongoing drought conditions in the Colorado River Basin. The basin supplies water to Lake Mead, which accounts for 90% of Southern Nevada's water. Managing demand and meeting long-term needs are urgently required along with extensive planning to make sure that water consumption in the area falls within the amount of water available for use. The following subsections describe ongoing problems, existing water conservation efforts and long-term water resources management options for Las Vegas.

9.2.1.1 Drought in Lake Mead

Lake Mead is the reservoir for the southwest states' share of Colorado River water resources. It provides water for 20 million people in southern Nevada, southern California, and Arizona. Since 2000, Lake Mead's elevation at the Hoover Dam has declined more than 80 feet (see Figure 9.2).

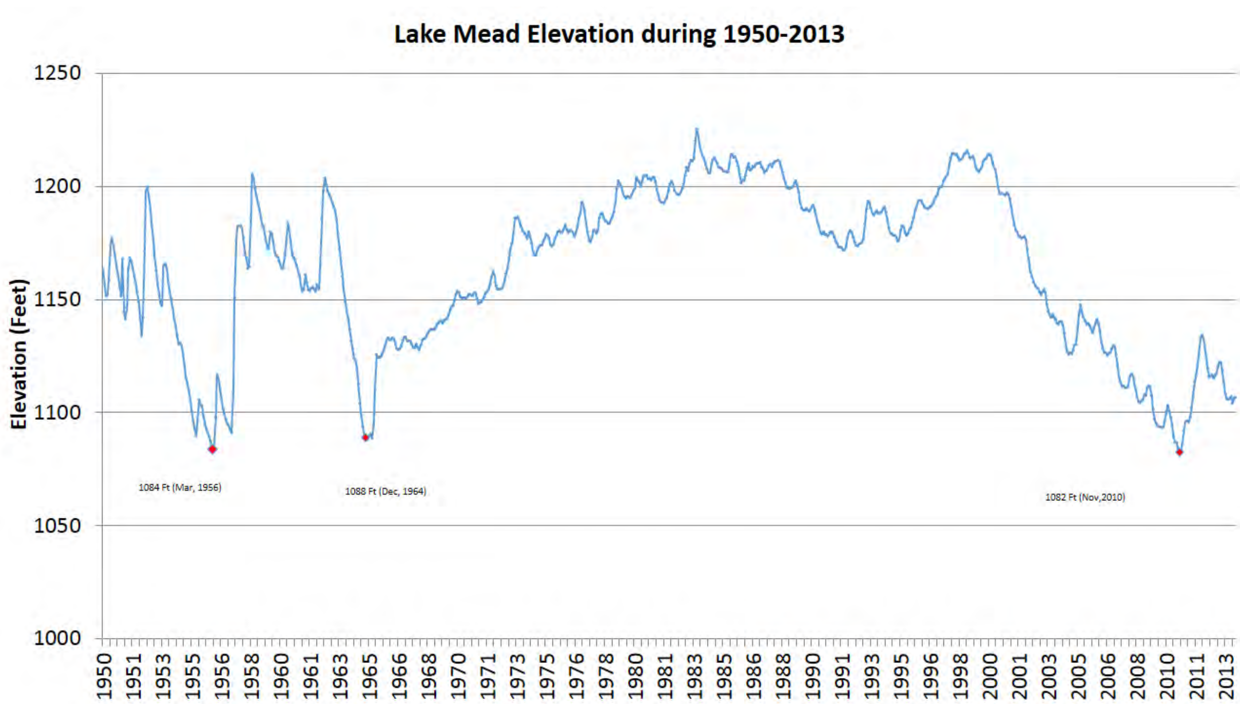

Figure 9.2 Lake Mead elevation from 1950 to 2012.

If Lake Mead's water level drops below 1,075 feet, the U.S. Department of the Interior will declare a water shortage on the river (SNWA, 2012). Figure 9.2 shows monthly records of elevation at Lake Mead from 1950 to 2013. The lowest elevation of 1,082 feet occurred in November 2010, during which time the Department of the Interior was about to declare a shortage on the river. These elevation drops lead to a reduction in Nevada and Arizona's available Colorado River water allocation (SNWA, 2012).

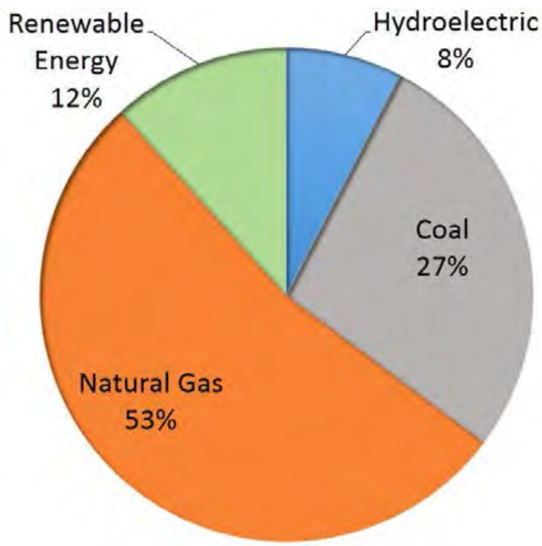

Figure 9.3 Electricity generation by source type for Nevada as of February 2014. Data from EIA (2014c).

9.2.1.2 Water resource management for electricity generation in Las Vegas area areas

Most of Nevada's electricity is generated thermoelectrically, a process that relies on a significant amount of water resources due to the water required for steam cooling and other processes. Of Nevada's total electricity production, 53 percent is from natural gas and 27 percent is from coal. Moreover, from Nevada's energy portfolio in 2014, hydroelectric power accounts for 8 percent of total electricity generation (see Figure 9.3). Renewable energy (excluding hydroelectric) accounts for 12 percent of the electricity production in Nevada. Of the total renewable energy in Nevada, 82 percent came from geothermal energy and solar energy (EIA, 2014c).

During the past decade, the nation battled drought and adapted to dramatic changes in weather patterns. These warm, arid conditions are expected to continue through the next decade (SNWA, 2012). To cope with these changes, the Southwest Nevada Water Authority (SNWA) employs a multi-faceted approach to add flexibility to the state's water resources. Their primary approaches to water resource management included implementing a water conservation program, treating and reusing wastewater and extending water supplies, as described below.

- *Water conservation programs in Las Vegas*

To promote the efficient use of water and reduce water waste, the SNWA has created conservation programs in the Las Vegas area. Conservation is considered to be a valuable water resource that reduces overall demand and extends supplies. The SNWA utilizes several conservation tools to reduce water usage that include a combination of regulation, water pricing, incentives and education.

Established in 1991, the conservation program in southern Nevada aims to reduce water use for both indoor and outdoor consumption. The primary conservation programs are focused on regulating outdoor water uses, which make up the majority of consumptive water demand in southern Nevada.

In 1991, local government agencies adopted watering restrictions that prohibited watering during the hottest times of the day in the warmer months (SNWA, 2009). In 2003, the SNWA member agencies adopted more policies that include additional restrictions on landscape watering, vehicle washing, lawn installation, mist systems and golf course water use during declared droughts (SNWA, 2009).

Landscape water, for example, is prohibited from 11 a.m. to 7 p.m. in the summer, and limited to one day a week in winter and three days a week in spring and fall (SNWA, 2009). For residential vehicle washing, a positive shutoff nozzle is required, and commercial vehicle washing is prohibited unless water is captured to be treated and reused. Moreover, for lawn installation, turf is prohibited in the new residential front yards and commercial development. The use of commercial mist systems is limited to the summer months, and fountains and ornamental water features are prohibited except as allowed by jurisdiction policy. Golf courses are subject to mandatory water budgets of 6.3 acre feet of water (SNWA, 2009).

Water rates are one of the most effective conservation tools. The SNWA member agencies have adopted conservation-oriented water rates that support the community's conservation goals. The SNWA regularly assesses the rate to ensure that it corresponds with inflation and maintains their effectiveness in encouraging conservation (SNWA, 2009).

The SNWA also has a number of "water smart" incentive programs that invite the community to participate in the conservation effort. These water smart programs include a water-smart landscape rebate program, efficient landscape irrigation equipment, water-efficient technologies, water-smart car washes, a pool cover rebate program, water smart contractor program, water smart homes and water upon request.

To educate communities about the importance of conservation and how they can conserve water most effectively, the SNWA also created public education programs such as the water conservation coalition, water smart innovations, a conservation helpline, publication and media, demonstration gardens and H_2O university (SNWA, 2009). Details regarding both the SNWA incentive programs and education programs are summarized within the Appendix to this chapter.

SNWA's conservation efforts have reduced water consumption by roughly 21 billion gallons annually between 2002 and 2008 (SNWA, 2009). As a result, conservation remains an important element in planning and balancing the resource and infrastructure needs in southern Nevada.

- *Wastewater reuse and recycle*

Wastewater is reclaimed, treated and used as a resource in southern Nevada (SNWA, 2012). When southern Nevada directly reuses or returns flows to Lake Mead, additional reclaimed Colorado River water for irrigation or cooling are credited. These credits are referred to as “Return-flow credits.” Reclaimed water accounts for roughly 40 percent of domestic water, making it the second-largest water resource (SNWA, 2012). Southern Nevada reclaims wastewater through return-flow credits or direct reuse. Approximately 200,000 acre-feet or 62,700 million gallons of urban flow wastewater and runoff are returned to the Colorado River each year for return-flow credits. Direct reuse accounts for about 17,000 acre-feet per year or 5,542 million gallons per year (SNWA, 2012).

- *Extending water resources*

Intentional Created Surplus (ICS) are credits that accumulate when water agencies conserve or introduce additional water into the Colorado River. These credits can be earned through Tributary Conservation, Importation, System Efficiency and Extraordinary ICS.

The SNWA has created approximately 124,000 acre-feet (40,400 million gallons) of Tributary Conservation ICS from conveying Muddy and Virgin rivers water rights to Lake Mead for Colorado River credit (SNWA, 2012). For the Imported ICS, the SNWA transports groundwater from Coyote Spring Valley to Lake Mead by constructing facilities for conveying groundwater to Lake Mead, which totaled 4,000 acre-feet of groundwater or 1,300 million gallons in 2012 (SNWA, 2012). An “Extraordinary Conservation ICS” is the credit that is applied when both the “Imported ICS” and “Tributary Conservation ICS” are not used during the year and thus converted to credit for the following year.

Southern Nevada has an additional 40,000 acre-feet or 13,000 million gallons of Colorado River water available for consumptive use each year, which was created by the Warren H. Brock Reservoir near Gordon Wells, California to capture unused Colorado River water that eventually passes into Mexico (SNWA, 2012).

SNWA’s system Efficiency ICS also received water credit from the Yuma Desalting Plant (YDP) that conserved 30,000 acre-feet or 9,700 million gallons of irrigation return flow water, which was then returned to the Colorado River to adjunct water delivery obligations to Mexico (SNWA, 2012).

Moreover, Arizona and California struck an agreement with Nevada that allows the SNWA to bank an additional 200,000 to 400,000 acre-feet of Colorado River water between 2012 and 2016 in their resources.

Regarding infrastructure adaptation for water resource management, the SNWA is constructing a third intake tunnel for treatment and distribution, located approximately 350 feet beneath the surface of Lake Mead, to keep Lake Mead above shortage levels during critical drought conditions. The project is expected to be completed in 2014 (SNWA, 2012).

9.3 Holistic Water Resource Adaptation

9.3.1 Future energy production scenarios

In 2011, nearly 90 percent of electricity in the U.S. came from thermoelectric (coal, natural gas and nuclear) power plants (Clemmer *et al.* 2013), yet this percentage is projected to fall to 83 percent by 2040 (Figure 9.4) (EIA, 2014a). Note that the most recent EIA projections due not yet include projected impacts due to proposed GHG regulations.[36]

Growth in renewable generation is supported by many state requirements and by greenhouse gas (GHG) emission regulations. The proportion of U.S. electricity generation coming from renewable fuels (including conventional hydropower) is expected to increase from 12 percent in 2012 to 16 percent in 2040 (EIA, 2014a).

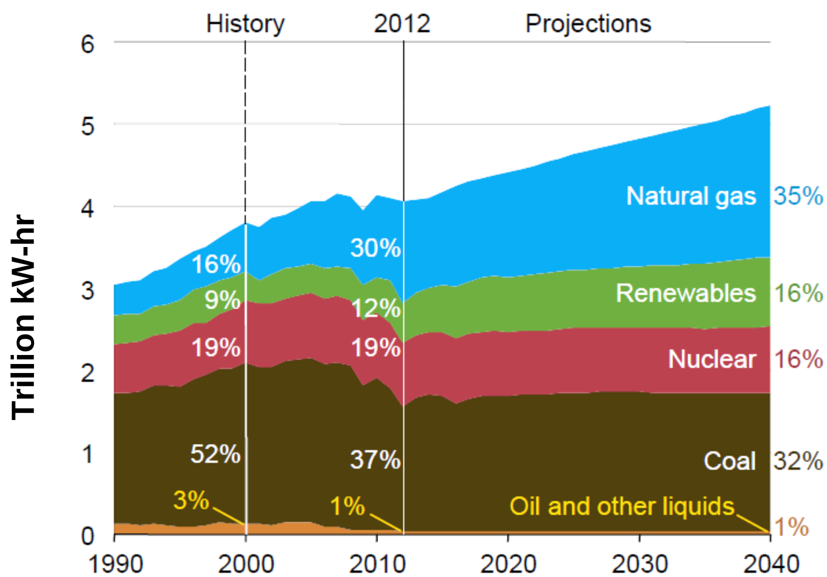

Figure 9 4 Electricity generation by fuel, 1990-2040 (trillion kilowatt-hours). From EIA (2014a).

To analyze the impact of different fuel sources on water withdrawals and water consumption for future electricity generation, the base and future scenarios were modeled using the Regional Energy Deployment System (ReEDS), an electricity model developed by the National Renewable Energy Laboratory (NREL) (Clemmer et al., 2013). The electricity portfolios within the model take into account existing state and federal regulations, and the relative economics of different electricity generating-technologies (Clemmer et al., 2013). ReEDS is a linear optimization program that analyzes the future impacts of different electricity-generating technologies on water withdrawals and consumption, along with carbon emissions, electricity and natural gas prices in the U.S. (Clemmer et al*.,* 2013). The major future electricity generation technologies within the model include supercritical coal and integrated gasification

[36] See Chapter 2 for further details regarding pending GHG standards for new and existing electric generating units.

combined cycle coal (IGCC), natural gas combined cycle (NGCC), natural gas combustion turbines (steam/Rankine cycle), fossil fuels with carbon capture and storage (CCS), nuclear, hydropower, wind, solar photovoltaic (PV), concentrating solar power (CSP), geothermal power and biopower with storage (Clemmer et al., 2013). When developing future scenarios, the cost and performance estimates for different electricity generating-technologies need to be taken into consideration. Key estimates for the ReEDS model are shown in Table 9.4. The U.S. Energy Information Administration (EIA) estimates that electricity demand in the U.S. will grow 0.8 percent per year between 2010 and 2050 (EIA, 2011a).

Table 9.5 Electricity modeling scenarios

Scenario	Key Assumptions and targets
1) Reference Case	Existing state and federal regulations
2) Carbon budget, no technology targets	Electricity sector contribution to a 170-Gt CO_2 eq US carbon budget through 2050
3) Carbon budget and higher nuclear and coal with carbon capture and storage (CCS)	29% nuclear generation by 2035 and 36% by 2050 15% coal with CCS generation by 2035 and 30% by 2050
4) Carbon budget and higher energy efficiency and renewable energy	20% reduction in electricity use by 2035 and 35% by 2050 50% renewable generation by 2035 and 80% by 2050

Note: Adapted from Clemmer et al. (2013)

Because the electricity generation portfolio varies greatly in different regions of the U.S., the ReEDS model also determines the geographic distribution of the technologies at the regional level based on relative economics, resource potential and electricity demand (Clemmer et al., 2013). For water-stressed regions such as the southwest and southeast, where water is limited for withdrawal and consumption, future energy production was used for the projected electricity generation scenarios (Table 9.4).

9.3.1.1 National electricity generation

Electricity generation from coal-fired power plants is expected to steadily decrease by 37 percent between 2010 and 2050 (Figure 9.5, EIA 2011a). This decline is initially due to announced coal plant retirements (included in the model), resulting primarily from low natural gas prices, the implementation of EPA regulations and state requirements for energy efficiency and renewable energy, and the higher cost of new coal plants compared with natural gas (Clemmer et al., 2013). Nuclear generation is also projected to decline due to the estimated 60-year lifetime for existing nuclear plants and the relatively high cost of building new plants. Renewable energy generation is expected to more than triple by 2030, due to state renewable electricity standards and federal tax credits. A more than six-fold increase is expected by 2050 due to projected cost reductions that make some technologies more economically competitive (Clemmer et al., 2013). Of the renewable energy technologies, wind and solar PV are expected to make the biggest contributions, providing 55 percent of the total generation in the U.S. by 2050 (Figure 9.5 scenario 4).

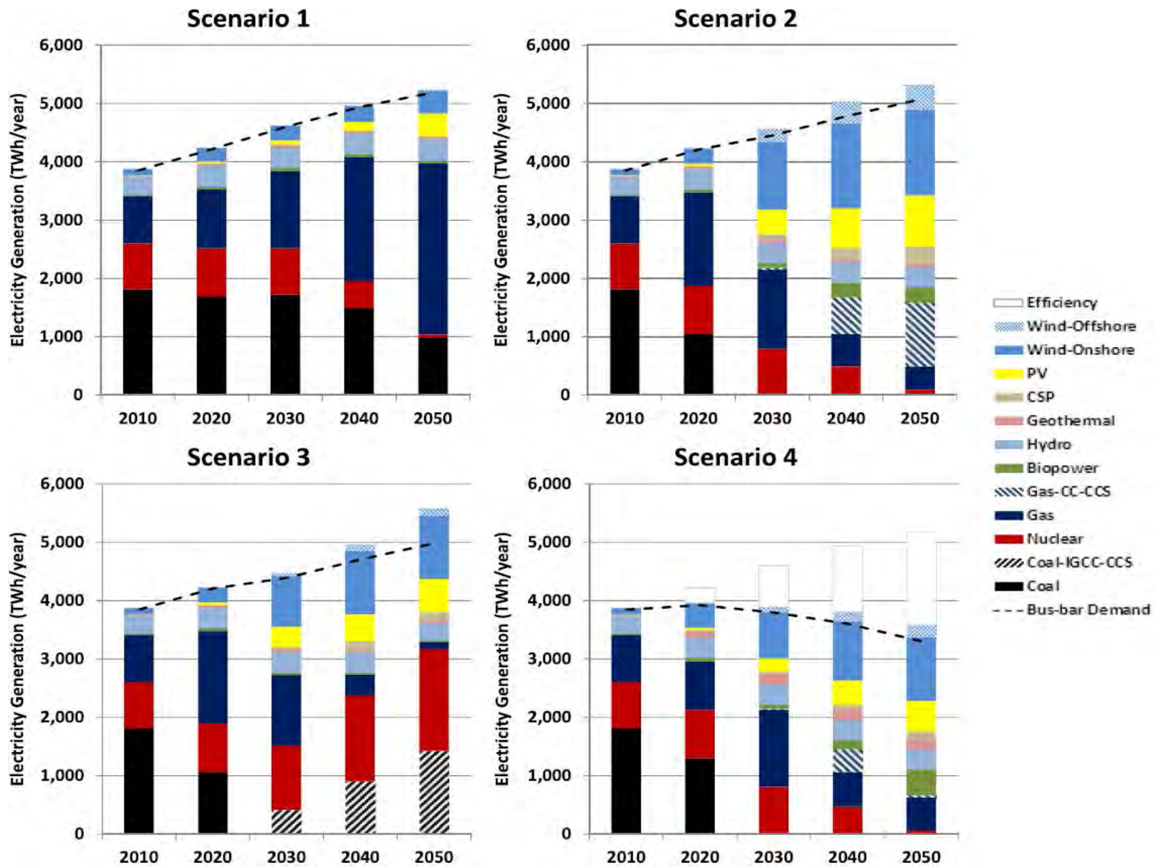

Figure 9.5 National electricity generation by scenario. Adopted from Clemmer et al. (2013). Scenario 1, reference case; Scenario 2, carbon budget, no technology target; Scenario 3, carbon budget with coal with CCS and nuclear targets; Scenario 4, carbon budget with efficiency and renewable energy targets.

9.3.1.2 Southwest

The southwest region analyzed by Clemmer *et al.* included California, Nevada, Arizona, Utah, New Mexico, Colorado and Wyoming. The southwest currently relies on natural gas (36 percent), coal (33 percent), nuclear energy (14 percent), hydroelectric power (10 percent) and other renewable energy sources (7 percent) (EIA, 2011a). In the reference case (Figure 9.6), non-hydro renewable generation increases from 7 percent to more than 38 percent, while natural gas generation grows to 39 percent (Clemmer et al., 2013). Renewable generation increases appreciably especially in scenario 4 that shows an increase to over 95 percent by 2050. With scenario 4, geothermal generation utilizing enhanced geothermal systems technology (EGS) provides a much larger share of renewable generation (36%) as it becomes more economically viable (Clemmer et al., 2013; EERE, 2007).

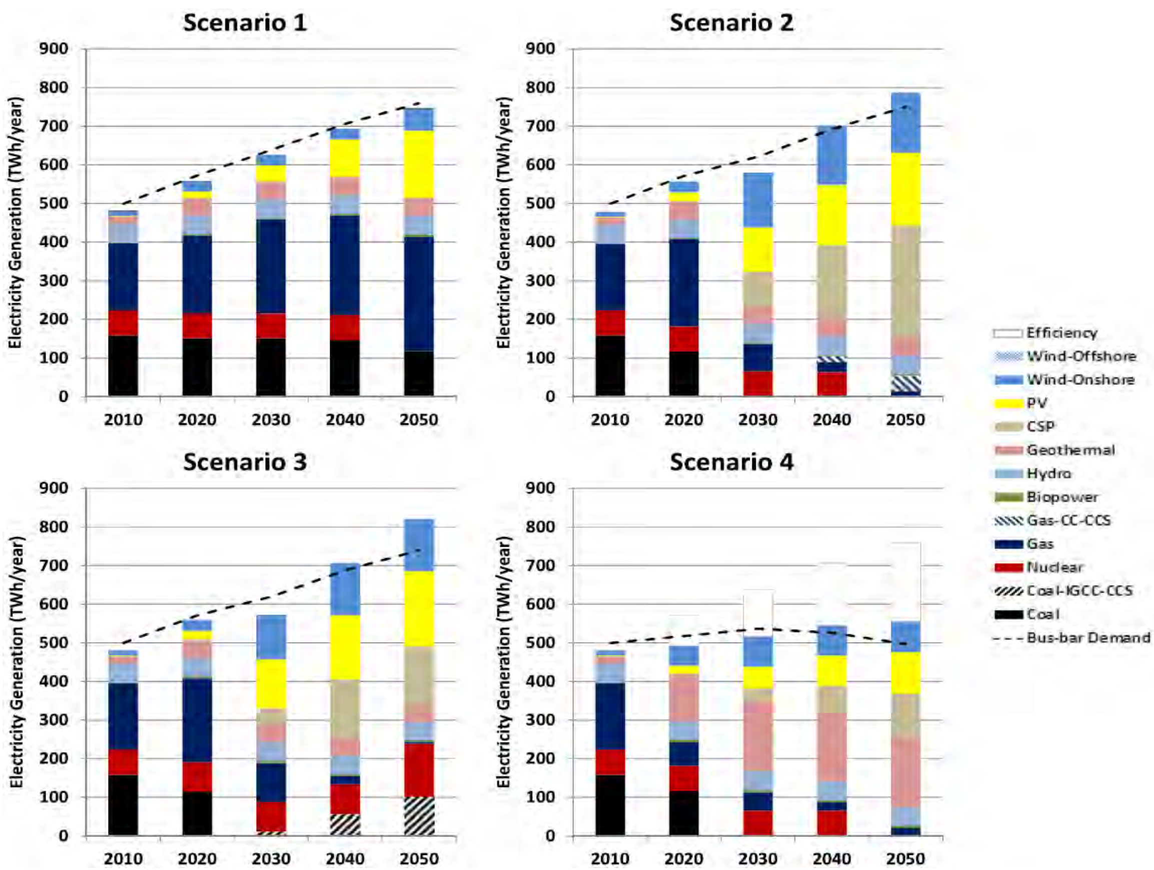

Figure 9.6 Electricity generation in the southwest by scenario. Adapted from Clemmer et al. (2013). Scenario 1, reference case; Scenario 2, carbon budget, no technology target; Scenario 3, carbon budget with coal with CCS and nuclear targets; Scenario 4, carbon budget with efficiency and renewable energy targets.

9.3.1.3 Southeast

The southeast region analyzed by Clemmer et al. included Mississippi, Alabama, Tennessee, Georgia, South Carolina, North Carolina and Virginia. In 2010, the southeast relied heavily on coal (47 percent), nuclear (27 percent) and natural gas (17 percent) (EIA, 2011a). Under the reference case, gas generation is projected to provide 75 percent of the region's total generation by 2050, as it replaces retiring coal and nuclear plants (Clemmer et al*.*, 2013). Figure 9.7 also shows that the southeast has an increase of renewable energy generation due to the region's relatively high intensity of solar PV, biomass and offshore wind resources. Scenario 4 shows an increase in solar PV to 28 percent, biomass to 26 percent and offshore wind to 15 percent by 2050.

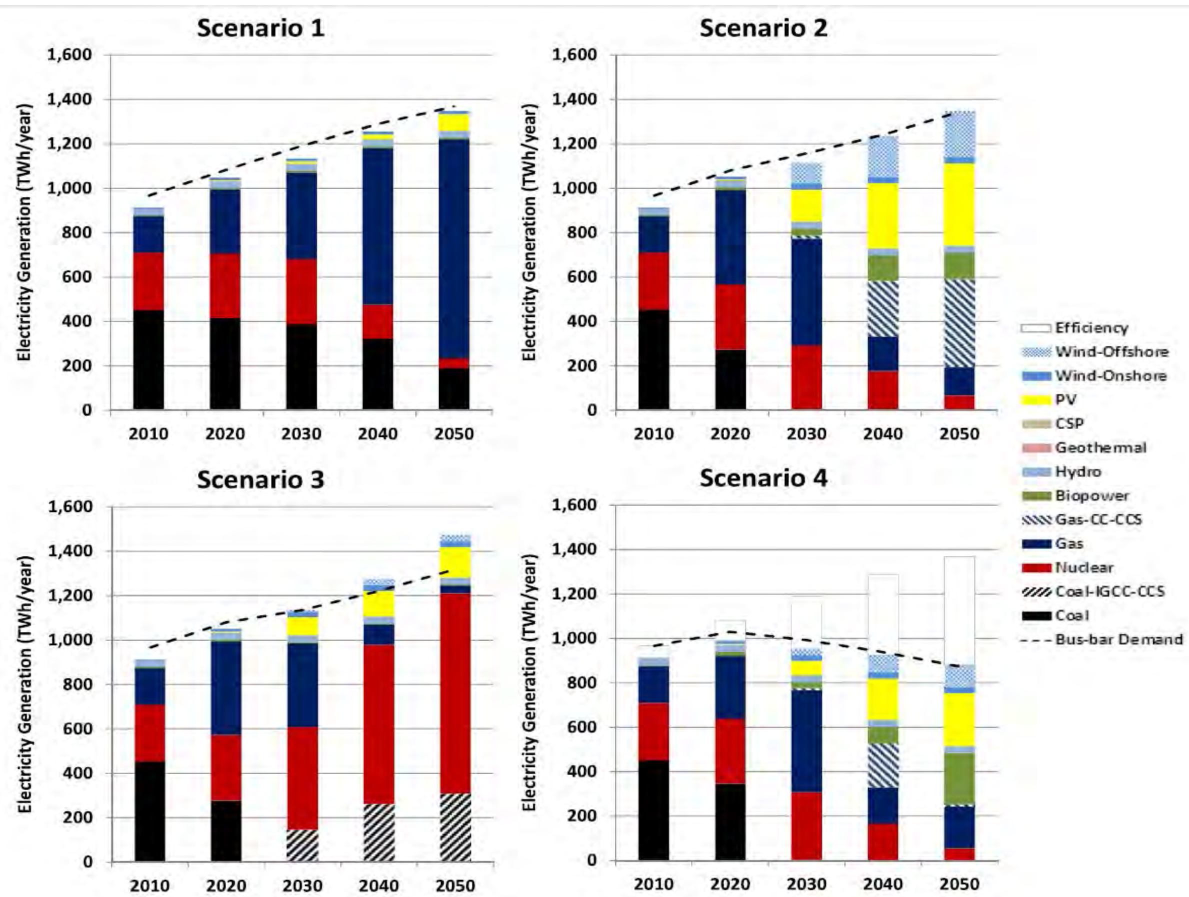

Figure 9.7 Electricity generation in the southeast by scenario. Adapted from Clemmer et al. (2013). Scenario 1, reference case; Scenario 2, carbon budget, no technology target; Scenario 3, carbon budget with coal with CCS and nuclear targets; Scenario 4, carbon budget with efficiency and renewable energy targets.

9.3.2 Water Demand Distribution and Water availability

According to the US Geological Survey, in 2005, power plants accounted for 41 percent of total freshwater withdrawals (USGS, 2005a). In 2005, thermoelectric power plant cooling processes accounted for 49 percent of all water withdrawals (freshwater and saline water) in the U.S., compared to 31 percent for agricultural uses and 11 percent for public supply (Kenny et al., 2009). Water withdrawals from thermoelectric power maintained a steady trend from 1985 to 2005 (Figure 9.8). Focusing on water consumption (consumptive use), the U.S. electric sector constituted about 3 percent of the national total in 1995, compared to more than 75 percent for the agricultural sector and 12 percent for public supply (Solley et al., 1998).

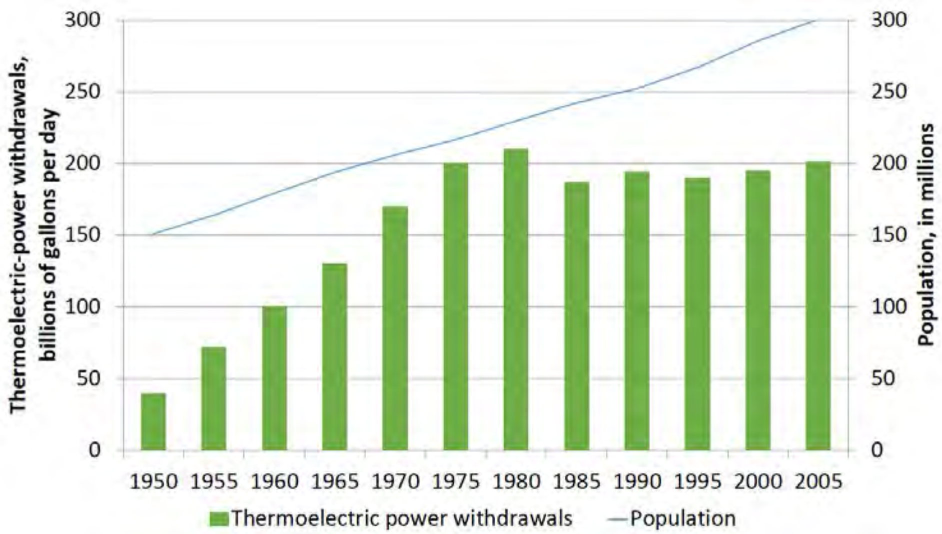

Figure 9.8 Thermoelectric-power water withdrawals 2005. Adopted from USGS (2005a).

The most important determinant for water demand variation is the choice of cooling technology (Macknick et al., 2011). As mentioned in Chapter 4, conventional thermoelectric generation uses two types of cooling systems: recirculation systems with cooling towers and once-through systems without cooling towers. Both systems use "wet cooling" of process steam via heat exchangers and can utilize either saline water or freshwater for cooling (NREL, 2012). Cooling systems can thus be classified under four general types based upon the source of cooling water and the type of cooling system utilized: once-through cooling using freshwater (OTF), once-through cooling using saline water (OTS), re-circulation cooling using freshwater (CCF) and re-circulation cooling using saline water (CCS) (NREL, 2012). The five states with the highest water withdrawals for each of the four general system types are shown in Tables 9.5 and 9.6.

Table 9.6 The top 5 states with the highest thermoelectric-power water withdrawals for once-through cooling type in 2005

Withdrawals for once-through cooling in million gallons per day											
Groundwater						Surface water					
State	Fresh	%	State	Saline	%	State	Fresh	%	State	Saline	%
HI	25.3	28.0%	HI	1450	99.8%	IL	11800	9.3%	CA	12600	22.4%
OH	16.7	18.5%	FL	3.26	0.2%	MI	9140	7.2%	FL	11300	20.1%
IA	13.6	15.1%				TN	8750	6.9%	MA	5940	10.6%
AZ	5.13	5.7%				OH	8550	6.7%	NJ	5190	9.2%
IN	4.27	4.7%				TX	8180	6.4%	NY	4880	8.7%

Note: Adopted from USGS (2005).

Table 9.7 The top 5 states with the highest thermoelectric-power water withdrawals for recirculation cooling type in 2005

Withdrawals for recirculation cooling in million gallons per day											
Groundwater						Surface water					
State	Fresh	%	State	Saline	%	State	Fresh	%	State	Saline	%
LA	97.4	23.2%	UT	4.18	99.8%	KY	2670	17.3%	NJ	273	57.9%
TX	55.8	13.3%	NJ	0.01	0.2%	PA	2320	15.1%	FL	140	29.7%
AZ	45.3	10.8%	AL	0	0.0%	LA	1670	10.8%	TX	35.2	7.5%
MS	35.4	8.4%	AK	0	0.0%	NC	1660	10.8%	MA	14.8	3.1%
MO	17.7	4.2%	AZ	0	0.0%	TX	1450	9.4%	DL	8.4	1.8%

Note: Adopted from USGS (2005)

In 2008, about 43 percent of thermoelectric generators in the U.S. used once-through cooling, 56 percent used recirculating and 1 percent used dry-cooling. Including renewable energy generations, 30 percent of the total electricity generation in the U.S. involved once-through cooling, 45 percent recirculating cooling, and 2 percent dry-cooling (UCS, 2013). In 2010, referring to Chapter 4-Figure 4.2, the total electricity generation increased to 58.2 percent for recirculating systems and reduced to 41.6 percent for once-through cooling systems. Generally, less water is required for withdrawal when cooling water is recycled through cooling towers or ponds compared to once-through cooling. Consumptive water loss (i.e., loss through evaporation) for recycled cooling systems is approximately 60 percent of the total water withdrawal for that method, but accounts for only two percent of total water withdrawal for once-through cooling (Solley et al., 1998).

Sources of energy and cooling technologies used to generate electricity determine the quantities of water consumption (Macknick et al., 2011). The water demand projection for power plant cooling can be estimated using electricity generation (by source of energy and cooling technology type) and average water use (withdrawals or consumptions) in gallons per unit of electricity (Kilowatt-hour) for each type, as shown in Figures 9.9 and 9.10. The data in Figures 9.9 and 9.10 were calibrated with the ReEDS estimated dispatch of a historical year (2006) to estimate regional variations and calculate consumption values. From this calibration, the water withdrawal and consumptive factors for each cooling technology were found to vary widely between regions (NREL, 2012).

As reported in Chapter 4.4.2, the volume of water withdrawn in coal plants operating once-through systems in 2010 was, on average, 30 times greater than those operating recirculating systems. The comparison was in close agreement with that found in the database in 2006 shown in Figures 9.9 and 9.10.

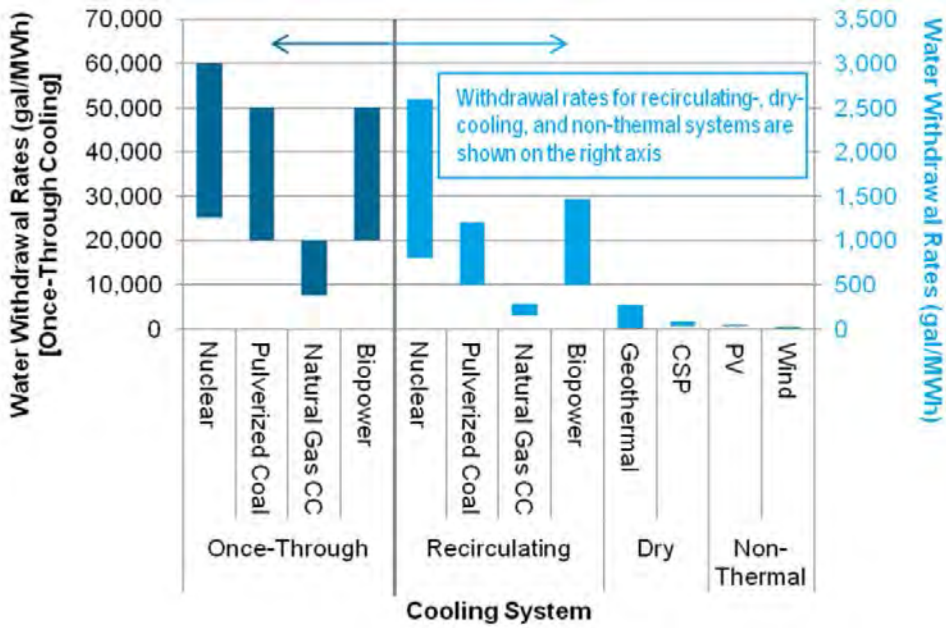

Figure 9.9 Overview of water withdrawal factors by technology. Adopted from NREL (2012).

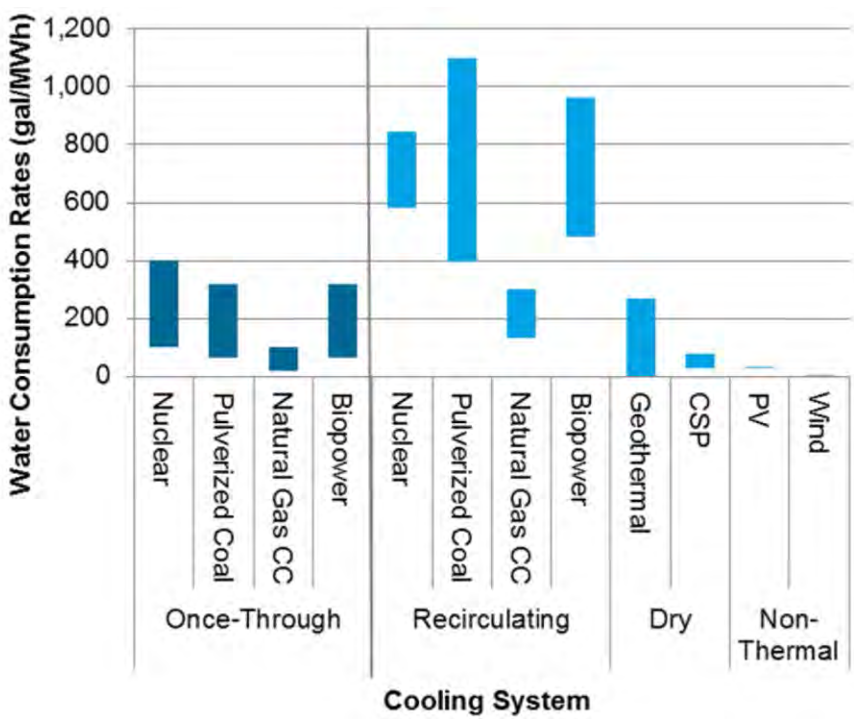

Figure 9.10 Overview of water consumption factors by technology. Adopted from NREL (2012).

9.3.2.1 Water demand projection for future electric power generation scenarios

Changes in future electricity generation in the U.S. will have important implications for future water use. Changing water availability due to competing demands and climate variability has been taken into account in water demand projections for electricity generation (Clemmer et al., 2013).

The ReEDS model calculates results of future sources of electricity generation with low-carbon emissions. The energy portfolio results will include both thermoelectric and renewable energy according to the scenarios (Table 9.4). The future electricity generation model also incorporated changes in energy costs, technologies, policies and regulations that impact future electricity generation planning in the U.S. (Clemmer et al*.,* 2013).

The choice of models and model assumptions are important. The cost and performance assumptions for different electricity-generating technologies used in the reference scenarios were retrieved from EIA's Annual Energy Outlook 2011 (Clemmer et al., 2013; EIA, 2011a). The Assumption for Annual Energy Outlook (AEO) 2011 was based on laws and regulations in effect before October 31, 2010, and was used in the National Energy Modeling System (NEMS) to generate the projections in the AEO 2011 (EIA, 2011b).

The ReEDS model can produce results for 134 power control authorities (PCAs) (shaded areas) for all electricity-generating technologies, and for 356 wind and concentrating solar power (CSP) resource regions (see Figure 9.11). ReEDS has a higher spatial resolution than the NEMS model. Regions can be aggregated up to the state level, the regional transmission organization (RTO), the North American Electricity Reliability Council (NERC) regional level (darker black lines), or for the three major electricity interconnections (red lines). Thus, ReEDS offers greater resolution for analyzing water impacts at any relevant geographic scales (Clemmer et al., 2013).

Clemmer et al., 2013 applied the ReEDS model to determine which types of electricity generating-technologies at the national and regional levels would meet the carbon budget and technology target. These selections are then used to calculate the impacts on national water withdrawals and consumption from the electricity sector. The model also takes into account the impact on electricity and natural gas prices. However, according to Clemmer et al., 2013, the produced results are specifically for national, southwest and southeast regions, and did not mention the electric dispatch between interconnected regions.

From the reference scenario's results in the ReEDS model (Clemmer et al., 2013), national water consumption (consumptive use captures evaporative losses from the cooling process) increases slightly (0.6 percent) by 2030 as increased electricity demand is met primarily with natural gas combined cycle plants with no substantial change in coal and nuclear generation.

Water consumption in 2050 of the base scenario, is 34.2 percent lower than the 2010 levels, as coal and nuclear generation is substantially reduced and replaced with natural gas and renewable generation (Clemmer et al., 2013). Scenario 4 (see Table 9.4) in the ReEDS model predicts a substantial reduction in water consumption in 2050 due to a reduction in electricity demand and increased penetration of renewable technologies, which decreased to 85.2 percent from 2010.

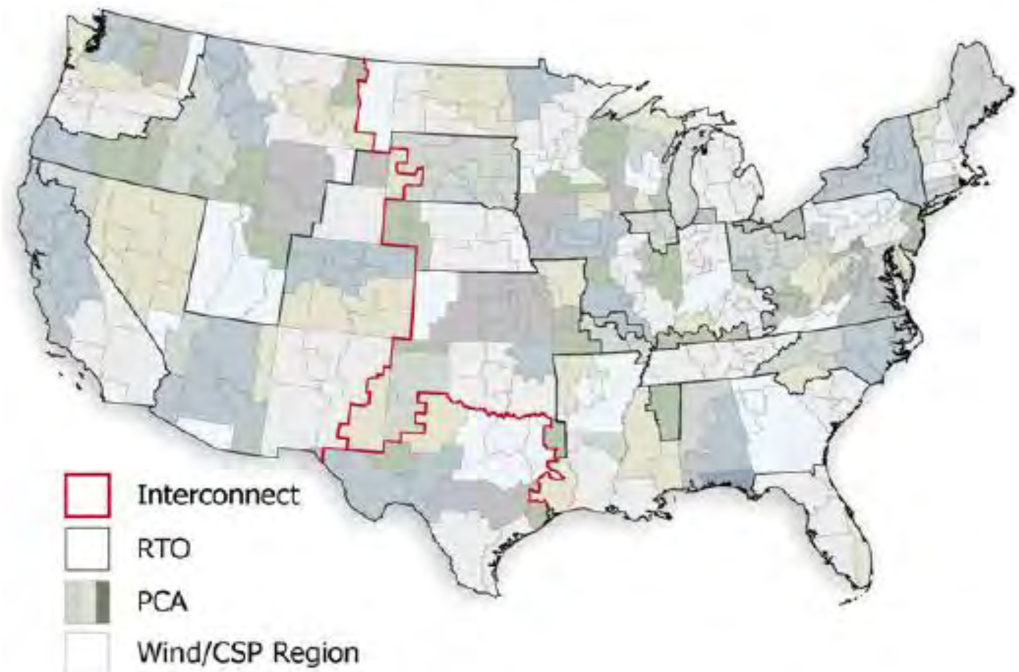

Figure 9.11 ReEDS modeling regions including the Interconnect, Regional Transmission Organization (RTO), Power Control Authorities (PCA), and Wind/Concentrating Solar Power (CSP) Region. Adopted from Clemmer et al. (2013).

9.3.3 Adaptation of electricity generation water use

9.3.3.1 Water conservation

<u>Water conservation through cooling technologies</u>

Most thermoelectric plants use water in steam cooling systems and the water loss from evaporation accounts for most of the water consumption at the majority of thermoelectric plants in the U.S. (Ciferno et al., 2010). As mentioned in Chapter 4, the two main methods of cooling are once-through systems and wet-recirculating (closed loop) systems. New power plants use once-through cooling because of the significant amount of water withdrawals and the disruptions to the local ecosystems (EIA 2014b) and to comply with EPA ecological flow and discharge temperature regulations.

In 2010, the U.S. Geological Survey (USGS) initiated a study to estimate water consumption by thermoelectric power plants as part of the USGS National Water Use Information Program and the agency's broader mission to provide scientific information to manage U.S. water resources (Diehl et al., 2013). Macknick, Newmark and Hallett from the National Energy Technology Laboratory also have developed water consumption and water withdrawal factors for the operational cycle across and within fuel technologies and for differing cooling technologies. They found that concentrating solar power technologies and coal facilities with carbon capture and sequestration capabilities have the highest water consumption when using recirculating cooling systems. Non-thermal renewables such as photovoltaic and wind have the lowest water consumption in cubic meter per megawatt hour (Macknick et al., 2012). Details of operational water consumption and withdrawal factors are depicted in Figures 9.9, 9.10, and 9.12, and in Table 9.3. As Figure 9.12 shows, the cooling system employed has a greater impact on water consumption than the particular technology used for generating electricity (Macknick et al., 2012).

Dry cooling is another option for reducing water-consuming cooling technology. Water usage in cooling systems can be reduced by two to ten times (see Figure 9.12) when utilizing dry cooling technology instead of a re-circulating cooling system. Thus, the choice of cooling system plays a significant role in the planning and development of any future thermoelectric generation capacity (Macknick et al., 2011).

Water conservation during high demand periods using hybrid technologies

Dry cooling systems, known as air cooled condensers, are cooling systems that condense steam and transfer the waste heat to the atmosphere without the consumption of water. Dry cooling systems use air instead of water to cool the steam exiting a steam turbine, which can decrease total water consumption by more than 90 percent (UCS, 2013). All of the heat rejected from the steam is absorbed in the form of sensible heat gain in the ambient air (Stultz and Kitto, 1992). The drawback of the dry cooling system is high energy consumption that might increase costs or decrease efficiency (Macknick et al., 2012). Dry cooling systems consume a large amount of energy because the systems require air to be passed over the steam by one or more large fans. This requires a significant amount of electricity (EIA, 2014b). Thus, the dry cooling systems are less suited for large plants that use a substantial amount of steam such as those powered by coal or nuclear energy (EIA, 2014b).

By combining wet and dry cooling systems, the hybrid-cooling system has potential for water conservation and energy-efficient production. Hybrid cooling systems use water for cooling during summer months and air for cooling during cooler months, or operate in unison, which increases overall cooling efficiency (WRA, 2008). Hybrid technologies are more likely to be used with certain generation technologies, such as Concentrating Solar Power (CSP) trough, CSP tower and Geothermal Binary (Figure 9.12). The water consumption reduction for hybrid cooling systems from re-circulation cooling accounts for 63 percent and 78 percent for CSP trough and CSP tower, respectively (Figure 9.12).

9.3.3.2 Water reuse and replacement

Saline water use for cooling systems

Of the available cooling technologies (Table 9.7), recirculation cooling systems with saline water and once-through cooling systems with saline water are alternatives that should be considered for freshwater replacement in coastal regions. The top five states that withdraw surface saline water for the once-through cooling processes are California, Florida, Maryland, New Jersey and New York (Table 9.5) (USGS, 2005). For re-circulation cooling processes, the top five states that use saline water are New Jersey, Florida, Texas, Maryland and Delaware (Table 9.8) (USGS, 2005).

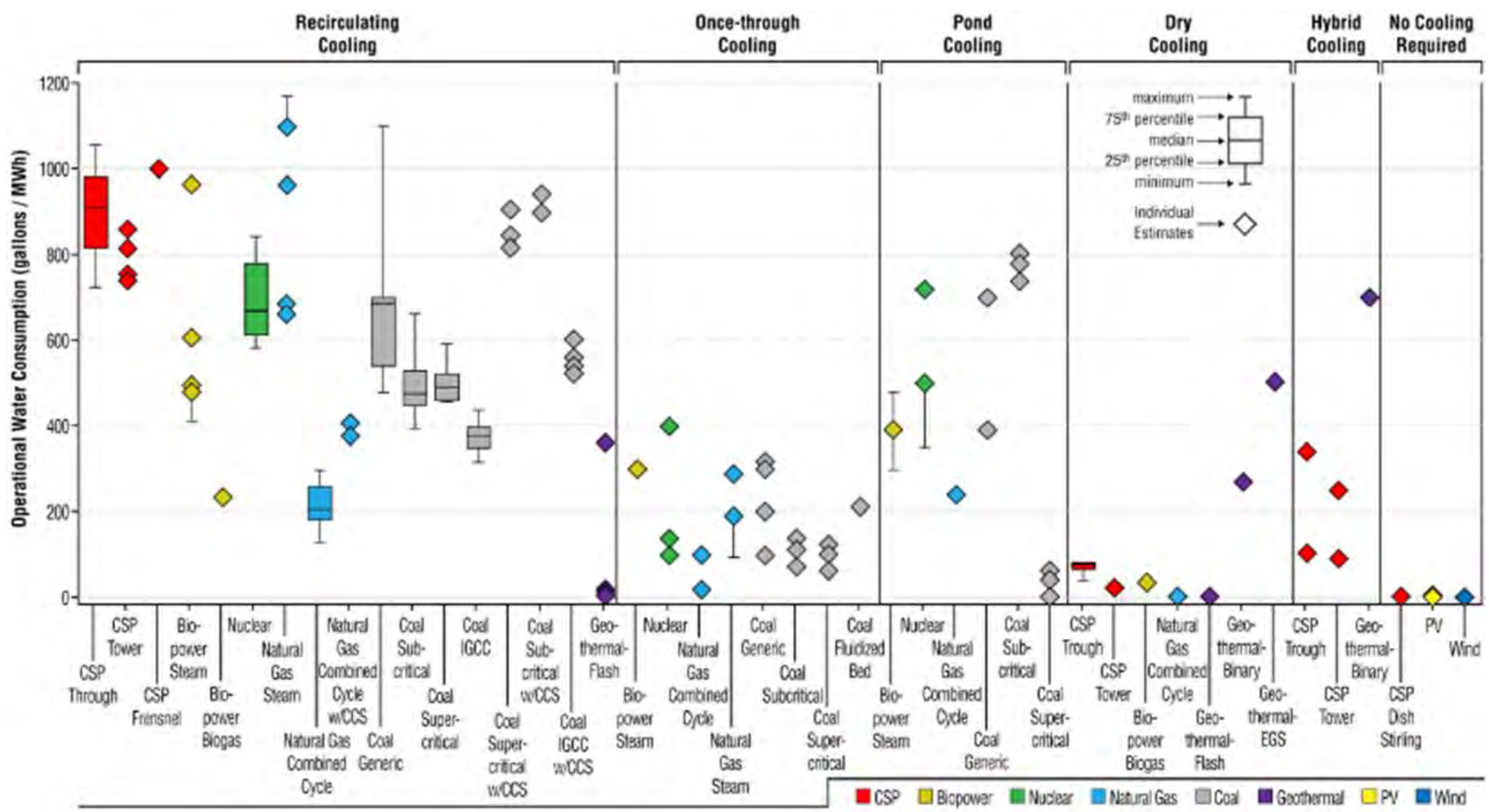

Figure 9.12. Operational water consumptive factors for electricity generating technologies. Copyright IOP Publishing, 2012 (http://iopscience.iop.org/1748-9326/7/4/045802/article#erl444337fig1). Used according to IOP terms of use for non-commercial purposes.

In 2005, thermoelectric-power withdrawals made up an estimated 56,700 million gallons per day of saline water from surface water and 1,450 million gallons per day of saline water from groundwater (USGS, 2005b). The total saline withdrawals from both surface and groundwater accounted for 29 percent of the total water withdrawals for thermoelectric-power in the U.S. (USGS, 2005a).

The use of high salinity makeup water for a cooling tower typically imposes a loss of operating efficiency of four to eight percent. Due to the requirement of corrosion-resistant construction materials, the cost in construction can increase 35 to 50 percent compared to freshwater towers of comparable cooling capability (Maulbetsch and DiFiippo, 2010).

Table 9.8 Cooling-system types used to classify plant by cooling system technology*

EIA Cooling Type	Cooling System Type
Dry(air) cooling system	Air cooling systems
Hybrid cooling systems	Hybrid: recirculation cooling pond(s) or canal(s) with dry cooling
	Hybrid: recirculating with forced draft cooling tower(s) with dry cooling
	Hybrid: recirculating with induced draft cooling tower(s) with dry cooling
Once-through cooling systems	Once through with cooling pond(s) or canal(s)
	Once through, freshwater
	Once through, saline water
Recirculating with cooling systems	Recirculating with cooling pond(s) or canal(s)
	Recirculating with forced draft cooling tower(s)
	Recirculating with induced draft cooling tower(s)
	Recirculating with natural draft cooling tower(s)

Note: Adopted from (EIA, 2010).

Treated wastewater for cooling systems

As the availability of freshwater for cooling processes in thermoelectric power production becomes increasingly limited, alternative sources of water for power plant cooling are of interest for both existing and future power plants (Vidic et al., 2009). Reclamation of wastewater for cooling can use millions of cubic meters of freshwater especially in semi-arid and arid areas that require extensive wastewater reuse. Reused wastewater for power plants, if properly planned, may provide an economically efficient solution for water shortage situations.

According to recorded inventories of U.S. power plants, a total of 38 power plants across 15 states use reclaimed water in the cooling water system (Vidic and Dzombak 2009). The power plants that use treated municipal wastewater are located in Arizona, California, Colorado, Florida, Iowa, Massachusetts, Maryland, Minnesota, New Jersey, Nevada, Oklahoma, Oregon, Rhode Island, Texas and Virginia (Vidic and Dzombak 2009). In 2012, amongst 5,400 power plants, 60 plants used reclaimed water for cooling systems, which were found mostly in California, Florida, Texas and Arizona (Cooper, 2012; Veil, 2007).

Among all possible sources of impaired water that could potentially be used in power production, secondary treated municipal wastewater is the most common and widespread source in the U.S. Therefore, particular attention is given to a comprehensive analysis of the quantities, availability and proximity of this impaired water for use in existing and future power plants (Vidic and Dzombak 2009).

Vidic and Dzombak (2009) studied the use of wastewater in recirculating cooling water systems at thermoelectric power plants. Their evaluation included an assessment of water availability based on proximity and relevant regulations, as well as the feasibility of managing cooling water quality with traditional chemical management schemes. Their feasibility study includes chemical treatment to prevent corrosion, scaling and biofouling.

Their assessment in 2007 revealed that 81 percent of power plants proposed for construction would have a sufficient cooling water supply from one to two publicly owned treatment works (POTW) within a 10-mile radius, while 97 percent of the proposed power plants would be able to meet their cooling water needs with one to two POTWs within 25 miles. Moreover, 75 percent of the existing thermoelectric power plants in 2007 would have a sufficient cooling water supply from one to two POTWs within a 25 mile radius.

While there are no federal regulations specifically related to impaired water reuse, a number of states have introduced regulations. Veil (2007) summarized that only nine states had regulations or requirements for industrial water reuse activities. These states are California, Florida, Hawaii, New Jersey, North Carolina, Oregon, Texas, Utah and Washington.

9.4 Summary of U.S. GAO Report on Climate Change Energy Infrastructure Risks and Adaptation

This section summarizes major findings related to the water-energy nexus that are contained within the 2014 U.S. Government Accounting Office (GAO) report entitled "Report to Congressional Requesters – Climate Change Energy Infrastructure Risks and Adaptation Efforts" (GAO, 2014). According to the U.S. GAO, the energy sector's demand for water will increasingly compete with rising demands from the agricultural and industrial sectors, among others (GAO, 2014). EPA found that water from snowpack declined for most of the western states from 1950 to 2000, with losses at some sites exceeding 75 percent (EPA, 2010). Annual stream flows are expected to decrease in the summer for most regions and drought conditions have become more common and widespread over the past 40 years in the Southwest, southern Great Plains and Southeast (GAO, 2014). Moreover, groundwater resources are being depleted in multiple regions (USGCRP, 2013; USGS, 2013). Research by the Electric Power Research Institute (EPRI) indicates that approximately 25 percent of existing electric generation in the U.S. is located in counties projected to be at high or moderate water supply sustainability risk in 2030 (EPRI, 2011). According to GAO (2014), the USGCRP's 2009 studies suggest that every one percent decrease in precipitation results in a two to three percent drop in stream flow. In the Colorado Basin, such a drop decreases hydropower generation by three percent.

Hydroelectric generation is a major source of electricity in some regions of the U.S., particularly the northwest, and is highly sensitive to changes in precipitation and river discharge

(GAO, 2014). Rising temperatures can reduce the amount of water available for hydroelectric generation due to increased evaporation (USGCRP, 2009; GAO, 2104). Increased evaporation rates or snowpack changes can affect both the volume and timing of water available for hydroelectric generation (GAO, 2014). Water is also required for coal and uranium mining, the extraction and refining of petroleum and natural gas, and for biofuel energy crop production (GAO, 2014).

To develop adaptation strategies for infrastructures potentially impacted by changes in precipitation patterns and drought, GAO cited specific examples of technological options to improve climate resilience, including: enhancing restoration technologies and practices to maintain or expand regional wetlands and other environmental buffer zones, increasing the efficiency of electric generation through integration of technologies with higher thermal efficiencies than conventional coal-fired boilers, and improving water reservoir management and turbine efficiency for more efficient hydroelectric generation (GAO, 2014; U.S. DOE, 2013). GAO (2014) also summarized the federal government's role in energy infrastructure as it relates to water resources management (See Table 9.9).

Because electricity generation infrastructures are vulnerable to severe weather that can interrupt operations, the ability to adapt to water supply changes is especially necessary for plants that rely on water resources (GAO, 2014). This adaptive capacity is built through water and natural resource governance that invest in infrastructures to provide increased water storage, such as dams and reservoirs, desalination plants, wastewater recycling facilities, groundwater wells and urban storm water drainage systems (Smith and Barchiesi, 2013).

U.S. DOE Office of Fossil Energy and the National Energy Technology Laboratory (NETL) are developing advanced water management technologies applicable to fossil fuel and other power plants in three specific areas (GAO, 2014; Ciferno et al., 2010):

1. Nontraditional sources of process and cooling water to demonstrate the effectiveness of utilizing lower quality water for power plant needs.
2. Innovative research to explore advanced technologies for the recovery and use of water from power plants.
3. Advanced cooling technology research that examines wet, dry and hybrid cooling technologies.

These initiatives can help advance the adaptive efforts that private companies are making to incorporate less water-intensive technology (GAO, 2014).

Infrastructure Adaptation in Las Vegas

To demonstrate water shortage adaption, a power plant in Las Vegas and its application of dry cooling technology provides a valuable example. The plant's dry-cooled technology at Silverhawk Power Station, located 35 miles north of Las Vegas, supports the water agency's conservation efforts by using 90 percent less water than a typical water-cooled plant. The facility also incorporates strict emission limits and the Best Available Control Technology for air quality. As a result, Silverhawk meets stringent air quality requirements, and will increase the availability of electric power to southern Nevada (SNWA, 2014).

Solar Power application is another example of infrastructure adaptation. The Southern Nevada Water Authority (SNWA) has incorporated various photovoltaic (PV) technologies into its water system operations. Solar panels provide covered parking at both the River Mountains

Water Treatment Facility and the Alfred Merritt Smith Water Treatment Facility, which produces a total of 308 kilowatts of clean energy (SNWA, 2014).

Table 9.9 Summaries of selected federal roles in energy infrastructure for water management

Summaries of Selected Federal	Roles in Energy Infrastructure
Agency Key activities related to energy infrastructure	Federal Energy Regulatory Commission (FERC) Hydropower • Issues licenses for the construction of new hydropower projects and for the continuance of existing projects (relicensing) • Oversees ongoing project operations, including dam safety inspections and environmental monitoring
Agency Key activities related to energy infrastructure	Environmental Protection Agency (EPA) • Regulates waste discharges into U.S. waters for discharge and treatment wastewater from power plants, petroleum refineries, and oil and gas extraction facilities • Regulates cooling water intake structures for power plant cooling systems • Prevents contamination of underground drinking water resources from underground wells associated with natural gas and oil production Source: GAO, 2014
Agency Key activities related to energy infrastructure	U.S. Department of the Interior Bureau of Reclamation (Reclamation) Hydropower • Assist in meeting the increasing water demands of the West while protecting the environment and the public's investment in these structures. • Emphasis on fulfilling water delivery obligations, water conservation, water recycling and reuse, and develop partnerships with customers, states, and Native American Tribes, and find ways to bring together the variety of interests to address the competing needs for limited water resources. Source: Bureau of Reclamation, 2013
Agency Key activities related to energy infrastructure	Bureau of Land Management (BLM) • Provide sites for new modern transmission facilities needed to deliver clean power to consumers • Review and approve permits and licenses from companies to explore, develop, and produce both renewable and non-renewable energy on Federal lands. Source: BLM, 2014
Agency Key activities related to energy infrastructure	U.S. Army Corp of Engineers (USACE) • Expand the usage of alternative fuels, such as biofuels, in vehicles and vessels • Complete energy and water audits • Implement energy and water conservation measures identified by the audits • Develop balanced and informed assessments of the safety of dams and evaluate, prioritize and justify dam Source: USACE, 2014

Note: Adapted from Appendix II of GAO (2014).

9.5 Summary

Due to prolonged droughts and population growth, there are concerns over water supplies to sustain agricultural requirements, municipal water use and energy production technologies that rely on water cooling and hydropower. Many demands and various consumers competing for water result in frequent over-allocation of water resources.

To support the sustainability of water supplies, water conservation programs together with operationalized water activities, such as recycling and water reuse including water infrastructure adaptation and water policies, were initiated. For example, the Southwest Nevada Water Authority employs a multi-faceted approach to reduce the drought exposure and create diverse and flexible water resources (SNWA, 2012). Their primary approaches to water resource management include implementing a water conservation program, treating and reusing wastewater, and extending water supplies.

Over the next several decades, increasing energy demand is expected to aggravate water shortage issues, especially the availability of freshwater for thermoelectric cooling (U.S. DOE, 2008). Moreover, while renewable energy sources reduce our reliance on coal-fired power plants that emit climate-changing greenhouse gases (GHG), some heavily rely on water sources. Hydropower production, for example, is sensitive to total runoff and reservoir levels.

Droughts have forced utilities in the Southwest to consider the use of new cooling technologies and sources of water to cool thermoelectric plants (Walton, 2010). Several projects are exploring the potential use of non-traditional sources of process and cooling water. The use of wastewater for thermoelectric cooling is increasing in the Southwest although the supply of urban wastewater may also be decreasing in some locations due to conservation policies (Walton, 2010). Municipal wastewater still appears to be the impaired source of water most likely to be locally available in sufficient and reliable quantities to provide cooling for thermoelectric generation (U.S. DOE, 2010). Using reclaimed water for cooling systems has several advantages, as it helps to save potable water and provides a reliable supply.

Available water savings in thermoelectric plants can be achieved via air cooling, through the use of non-traditional or impaired water sources, by recycling of plant wastewater and by increasing plant thermal efficiency (WNA, 2014). Advanced cooling technologies can also provide alternative approaches to reduce water consumption. For example, as discussed in Chapter 4, plants can implement condensing modules within the cooling towers or apply filtration methods to prevent scaling and increase the cycles of concentration. Other methods to reduce water consumption in cooling systems include the use of an air-cooled condensers (ACC), as well as the use of ice thermal storage within coal-fired cooling systems, which cools the intake-air to gas turbines. Furthermore, technologies that can recover usable water from alternative sources, such as water from the flue gas emitted by coal-fired power plants, can also help reduce water consumption. Discussed in Chapter 4, these technologies include liquid sorption technologies, flue gas sorption membranes and condensing heat exchangers.

Another approach for reducing freshwater consumption in coal-fired power plants, as mentioned in Chapter 4, is to enhance the fuel and improve plant efficiency. IGCC plants need approximately one-third of the engineered cooling when compared with conventional coal thermoelectric plants (WNA, 2014).

Using dry cooling systems or hybrid systems is a possibility for water-scarce regions when integrated with energy sources such as solar power and geothermal energy. Hybrid cooling systems are more applicable for cooling when utilizing an air-cooled condenser (ACC) for heat load rejection during summer months, which increases overall cooling efficiency.

Facilities can also consider saline water as a potential water source. Desalination is gaining attention in solar power plants in the southwestern area. Most desalting facilities are found in California and coastal regions. There is a possibility for a dispatch being shifted towards coastal areas and regional interconnects due to the abundance of salt water sources. In the Las Vegas case, the SNWA struck an exchange agreement with California to invest in desalination facilities in California in exchange for the use of a portion of California's Colorado River apportionment.

Water usage is influenced mostly by the cooling water demands for thermoelectric generation. The generation technologies that use non-renewable energy sources of coal, natural gas and nuclear power tend to require substantially more water withdrawal and water consumption than technologies that use renewable energy sources. Of the renewable energy sources, two generation technologies (photovoltaic and wind) used the least amount of water for cooling.

While a variety of sources have been used to supplement or replace freshwater for cooling systems, there are limitations for those applications. For example, a dry cooling system can decrease a power plant's efficiency. Moreover, the low quality of impaired water can cause the cooling system to be less effective, and a power plant's distance from a wastewater source can make using impaired water infeasible.

Local efficiency can greatly improve if power sources and water resources are in a proximity to the electric power plants, or if they are regionally interconnected. Availability of these resources may prove to be a significant factor of new power plant capacity to be built at or near existing facilities.

In conclusion, water climate, and energy issues are closely interrelated and cannot be addressed in isolation (Vidic et al., 2009). As both population and energy demand continue to increase in the U.S., freshwater scarcity will become a critically important issue. Both impaired and saline waters have potential to serve as alternative water sources to help meet future thermoelectric cooling demand (Vidic et al., 2009). There is already some experience with the use of impaired water for thermoelectric cooling. Examples include the use of treated municipal wastewater and the use of seawater in coastal. There will be an increasingly urgent need to find alternative water resources to replace freshwater demand for thermoelectric cooling purposes, particularly in water-stressed regions of the U.S.

Additionally, more research is needed to assess the regional and local water impacts of different types of electricity generation, and to analyze the water impacts of electricity-sector choices. More studies of viable energy resources and the impacts of geographical limitations may be useful in adapting the use of water locally in the generation sector. Finally, a review of the limitations of state and federal regulations on impaired water use and a series of feasibility studies of technologies to facilitate the use of impaired water are recommended.

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9.7 Appendix

Appendix Table 9.1 Detailed summary of Southern Nevada Water Authority's incentive programs

Water Smart Landscape Rebate Program	This program provides incentives for residential and commercial property owners to upgrade lawn to water efficient landscaping. The current program rebate amount is \$1.50 for the first 5,000 square feet of lawn removed and \$1 for additional lawn removed up to \$300,000.
Efficient Landscape Irrigation Equipment	This program pays up to half the cost of replacing inefficient irrigation controllers with smart controllers that can interrupt irrigation whenever the valley receives significant rainfall. These controllers are capable of reducing water use by 15 to 30 percent.
Water Efficient Technologies	Business customers who choose from proven conservation technologies that conserves at least 500,000 gallons of water per year, qualify for a rebate of up to \$150,000 per property.
Water Smart Car Wash	The water smart car wash program is a public-private partnership that encourages residents to use commercial car wash facilities, which recover all of their wastewater for treatment and reuse, instead of washing their vehicles at home.
Pool Cover Rebate Program	The SNWA pool cover rebate program pays up to half the cost of a swimming pool cover. Typical use of a cover is estimated to save 13,000 gallons annually on an average-size pool.
Water Smart Contractor Program	Landscape contractors who participate in the program need to ensure that their project meets specific criteria to conserve water. To obtain status as water smart contractor, licensed landscape contractors must attend SNWA water efficiency training and pass a proficiency exam.
Water Smart Home	The water smart home program certifies new homes as water smart, ensuring that homeowners are purchasing a home that can save as much as 75,000 gallons of water per year.
Water Upon Request	The SNWA and several local partners teamed up with local restaurants, which agree to serve water only when patrons request it.

Note: Adopted from SNWA (2009).

Appendix Table 9.2 Detailed summary of Southern Nevada Water Authority's education programs

Water Conservation Coalition	This coalition is a public-private partnership formed by community leaders to help increase water-efficient practices through initiatives such as speakers bureau, Business-to-Business Challenge and various public projects.
Water Smart Innovations	In 2008 the SNWA with the U.S. EPA's WaterSense program hosted the inaugural WaterSmart Innovations Conference & Expo to share information about conservation programs and water-efficient technologies.
Conservation Helpline	The Conservation Helpline is an information line that customers can call to obtain conservation information or report water waste.
Publications and Media	The SNWA regularly executes a comprehensive campaign of television, print and radio ads that educates the community on the need for water conservation and offers help through the SNWA website and Conservation Helpline. The SNWA also produces and distributes publications to help customers conserve water.
Demonstration Gardens	The SNWA promotes visits to the Springs Preserve, a 180-acre facility that offers hundreds of examples of water-efficient landscaping, as well as classes by master gardeners and horticulturists. The SNWA also funded conservation grants of up to $5,000 to develop demonstration projects for their own campuses.
H_2O University	The SNWA has partnered with the Springs Preserve to develop a comprehensive education program known as H_2O University for teachers in the Clark County School District.

Note: Adopted from SNWA (2009).

10 Conclusions and Recommendations

Timothy C. Keener[i], Marissa S. Liang[i], and Joseph McDonald[ii]

10.1 Conclusions

The use of hydrocarbons and other fossil fuels (natural gas, refined petroleum products, coal, etc.) for electricity generation and transportation, respectively, are the largest sources of energy demand and GHG emissions in the U.S. Cooling systems in thermoelectric generating facilities and biofuel crop cultivation consume significant quantities of water, approximately 3-4% for each of the two sectors. Each step in the production of fuels for the energy and transportation industries, and the use of these fuels for producing electricity involves the withdrawal, and sometimes consumption, of substantial amounts of water. For example, large amounts of water are required for drilling, extraction, and conversion of petroleum into products such as gasoline and diesel, which are the primary sources of fuel for the transportation industry. Other sources of fossil fuels such as shale or tar sands involve the use of extraction techniques which often require large amounts of energy and water. The U.S. Department of Energy estimates that approximately 70 – 260 million gallons of water per day is used for coal mining, including the water used for washing coal and cooling drilling equipment (U.S. DOE, 2006). After washing, most coal is transported to power plants by truck, rail or barges. In a few cases, however, finely ground coal is transported via pipelines as a slurry, which involves the use of hundreds of gallons of water per megawatt-hour (MWh) of electricity produced (Meldrum, 2013).

The majority of electricity in the U.S. is generated by combusting fossil fuels in a boiler to produce steam, and using the kinetic energy of the steam to generate electricity using steam turbines. In addition to the water required to produce steam, other uses of water in power plants include:

- Surface water withdrawals to condense steam after it passes through the steam turbine, with significant water consumption due to evaporation in cooling towers;
- Water required for scrubbing flue gases to meet Clean Air Act regulations;
- Water required to dispose of fly ash;
- Water lost during desalination.

The amount of water used in electric power plants has been found to be largely dependent on the type of fuel used in the plants. In 2012, coal was used to generate 37% of the total electricity, followed by natural gas, nuclear power, and renewable forms energy (hydroelectric, wind, solar, geothermal) at 30%, 19%, and 12%, respectively. Overall, this report has found a general trend of decreasing water-intensity as carbon-intensity of electric generation is decreased or as plant efficiency is increased.

Over reliance on non-renewable fuels and a push for greater energy independence led to the introduction of the Renewable Fuel Standards (RFS) under the 2005 Energy Policy Act, which was later amended in the Energy Independence and Security Act (EISA). EISA calls for a

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reduction in annual petroleum consumption by at least 20%, and an increase in the use of alternate fuels/biofuels such as ethanol and biodiesel by 10% by 2015, and a four-fold increase by 2022. There has been a steady increase in the demand for energy in the last century, and the demand is expected to increase, albeit at a slower rate, in the next few decades. In addition, the water consumption for producing the biofuels is significantly higher than for producing petroleum fuels, and this is dominated by the irrigation requirements of biomass cultivation. Increased use of biofuels may result in increased use of domestic agricultural, surface, and groundwater resources unless the water-intensity of biomass cultivation can be reduced. Transitioning from corn cultivation to the use of agricultural residues and cellulosic energy crops provides opportunities to reduce the water-intensity of both biomass cultivation and biofuel production in the U.S.

When taking into account the most recent AEO 2014 forecast trends of electrical demand, sources of electricity, consumption of biofuels and estimations of the expected rate of water consumption for these sectors in the U.S., the demand of water for energy is expected to increase over the next several decades unless new technologies that reduce water usage are implemented throughout the energy sector. Regulations that are expected to result in a reduction of the carbon intensity of electric power generation (e.g., the recently proposed EPA GHG regulations impacting new and existing thermoelectric generation) and the eventual transition of ethanol biofuels from cultivation of corn to cellulose (e.g., regulated volumes within the EPA RFS2 program) have significant potential to offset the impact of water usage from the energy sector.

The availability of water for power generation and biomass production for biofuels will also be affected by extraneous factors such as climate change, population growth and redistribution, domestic consumption, land use and regulatory criteria such as minimum ecological stream flow requirements, the Clean Air Act (CAA), and the Clean Water Act (CWA). All of these factors directly or indirectly impact water quality and quantity in water sources that will be used for cooling purposes or crop irrigation, thus influencing the ways energy production will adapt in the future. Climate changes are known to cause precipitation variations in intensity, frequency, seasonality, and quantity, leading to variations in surface water flow and groundwater levels, which in turn affect energy production processes. Climate change can also change the nature of precipitation (snowfall to rainfall) and the melting of snow pack – increasing spring runoff while reducing summer streamflow. Large-scale climatic model system simulations indicate that elevated GHG from power plant emissions and emissions from the transportation sector will further intensify atmospheric-oceanic interactions, thus producing greater impacts on climatic systems. Model simulations project 10% or more decreases in precipitation in southwest U.S.; changes in precipitation from snow to rain, resulting in a decrease in snow pack in the Rockies and Pacific northwest, and hence, stream flow; decreased precipitation and increased drought in southeast U.S.; and increased precipitation and flooding along the Great Lakes and northeast U.S. that may be responsible for water-borne pathogens and nutrient runoff.

Although there is uncertainty among different climatic models that consider different predictive variables, some general trends tend to emerge. Limited water availability in areas most affected by climate change, especially in areas with decreasing precipitation and increasing drought, is expected to increase water competition for power generation and biomass cultivation. This is especially pertinent for future energy production planning as the potential impacts of changing climate, population growth, and changing water quality on water usage, competition, mandated minimum ecological stream flows, water discharge criteria, and consumption in power plants needs to be considered in determining plant parameters. These parameters include the type and source of fuel, type of cooling to be used, and the treatment technologies that will be used to meet regulatory criteria. The effects of climate change on biomass cultivation are somewhat different from power generation in that biomass cultivation is dependent on land in addition to water-related factors mentioned above and the impact of regional differences on the irrigation needed for biomass cultivation results in much greater regional variation in water-intensity.

The electric generation and transportation sectors are the largest sources of emissions of CO_2, NO_X, SO_X and particulate matter in the U.S. These two sectors are also the largest contributors of GHG and short-term climate forcing emissions and thus are the primary anthropogenic contributors to global warming and climate change. Irrigation and thermoelectric power generation (especially the amount of water required to condense steam) are the largest users of water when considering water usage in areas affected by climate change. Various direct and indirect steps can be taken to minimize water use in thermoelectric power plants, depending on whether the main purpose is to directly reduce water consumption or if the purpose is to indirectly contribute to more sustainable water usage using advanced cooling technologies, water reuse and recovery, use of non-traditional sources for process and cooling water, and use of advanced wastewater treatment technologies. The use of recirculating systems (cooling towers) with thermoelectric generation is increasing due to regulations impacting discharge temperature and minimum ecological water flow. However, although once-through cooling systems tend to withdraw more water than recirculation systems with cooling towers, recirculating systems consume more water than once-through systems due to evaporative losses. This is expected to lead to a trend of increased water consumption as newer plants are brought on line unless consumptive losses are reduced. For example, a typical conventional coal-fired power plant withdraws between 20,000 – 50,000 gallons of water/MWh and 500 – 1,200 gallons of water/MWh for once-through and recirculating cooling systems, respectively. The estimates for water consumed were between 100 – 317 gal/MWh and 480 – 1,100 gal/MWh for the two systems, respectively. An alternative is to use air-cooled systems instead of water-cooled systems, albeit at a loss of energy efficiency. Air-cooled systems are rarely used for coal-fired thermoelectric generation but are used with increasing frequency for generation from natural-gas. Other opportunities to improve energy efficiency and reduce fuel and water usage include the use of supercritical and ultra-supercritical steam turbine plants, the use of supercritical oxy-coal systems with staged combustion, the use of high efficiency air-cooled heat exchangers, using condensing heat exchangers that condense water vapor in the flue gas for water makeup or reuse, using treated effluent from wastewater treatment plants, reducing wastewater discharge and using improved methods of flue gas scrubbing and flue gas desulfurization.

Water use for CO_2 capture and sequestration from future coal-fired power plants was modeled as part of this report. Methods to capture or eliminate CO_2 from the flue gas from coal-fired thermoelectric plants include post-combustion separation; pre-combustion separation, in which the fuel is decarbonized prior to combustion; oxy-fuel combustion, which uses pure oxygen for combustion, and which has the added advantage of reducing NOx in flue gas; and integrated gasification combined cycle (IGCC), wherein coal is converted at high temperature to form hydrogen/CO syngas, which after purification can be burned cleanly in a hybrid gas turbine with exhaust heat from the turbine used to provide heat energy for a steam turbine cycle. The captured CO_2 is either sequestered underneath the ground or in oceans, or the gas is compressed, dried, purified and stored for industrial use. Potential knowledge gaps with respect to CO_2 capture and sequestration include estimates of regional storage capacity for underground sequestration, potential leakage rates, cost data, and remediation options among others. However, there appear to be no insurmountable technical barriers to use geological or oceanic storage as an effective sequestration option for CO_2, thus leading to significant reductions in emissions of greenhouse gases into the atmosphere. The use of IGCC with CO_2 capture and sequestration has potential to significantly reduce water-intensity on a consumptive basis relative to coal-fired electric generation in part due to reduced steam cooling requirements and the potential to use dry- or hybrid wet-and-dry steam cooling.

The trend towards increased electric generating capacity from Natural-gas fired power has advantages that include reduced fuel costs, reduced greenhouse gas emissions relative to other fossil fuels, reduced criteria air pollution and air toxic emissions and the greater accessibility and abundance of natural gas in the U.S. through the use of newer extraction technologies such as hydraulic fracturing. Hydraulic fracturing involves drilling both vertically and horizontally to follow a geologic formation with trapped gas, injecting a mixture of water and chemicals at high pressure to fracture rock in the formation and allowing the gas to flow from the fractured rock to a wellhead where it is collected and processed for future use. The use of natural gas in electric power generation is expected to increase from 30% of total electricity production in the U.S. to approximately 63% in 2040. In addition to conventional, steam turbine-based natural gas power plants that are very similar to conventional coal power plants, natural gas can also be used to generate electricity via gas turbines as part of a natural gas turbine/steam turbine combined cycle (also known as natural gas combined cycle or NGCC). Similar to coal/IGCC systems, NGCC systems derive half or more of their generating capacity from the gas turbine and thus the steam cooling requirements for the steam turbine used in these systems are greatly reduced when compared to more conventional boiler/steam turbine systems. The reduced cooling requirements of the steam turbine stage result in reduced evaporative losses in the case of systems using cooling towers. The reduced steam cooling capacity can also enable the use of a dry cooling system or a hybrid wet-and-dry cooling system for steam cooling instead of cooling towers. The use of NGCC power plants can greatly help in reducing water consumption in water-stressed areas, thus leading to decreasing water withdrawals and improved water quality. Most new generating capacity from natural gas is expected to be via NGCC plants in order to meet expected GHG regulations. Other advantages of NGCC systems include much greater flexibility in powering the system on or off to meet electricity demand and the higher thermal efficiency of the Brayton/Rankine combined cycle relative to the Rankine cycle typical of conventional boiler/steam turbine plant designs.

In the past, small amounts of water had been used to extract natural gas from deep vertical wells. A single hydraulically fractured well can produce large volumes of fracture and formation water. The quantity and quality of this produced water varies across geologic formations. Much of the produced water is disposed of via injection wells, but increasing quantities of produced water are being treated for reuse. Other potential disadvantages of the hydraulic fracturing process include the potential to contaminate groundwater and chemical waste that has to be treated and disposed.

The amount of water withdrawn and consumed during electricity generation using coal (with and without integrated gasification combined cycle (IGCC) and CO_2 capture) and natural gas (gas-fired steam boiler/Rankine cycle and NGCC) is listed in Table 10.1. For comparison purposes, the amount of water withdrawn and consumed in nuclear power plants (the third most common form of thermoelectric generation) and concentrated solar power (an emerging thermoelectric technology) is also listed in the table. Note that the comparisons in Table 10.1 are only for recirculating cooling systems (e.g., cooling towers). The values listed in the table cover a wide range, and include both actual and modeled electricity generated from different types of coal (bituminous, sub-bituminous, lignite, etc.), different ambient air and water temperatures, and different water quality among other factors. Each of these variables affects water withdrawal and water consumption rates to a different extent, and the effect of each variable needs to be considered during power plant design. For comparison purposes, water withdrawn and consumed in thermoelectric plants with once-through cooling systems are also summarized in Table 10.2. Note that water withdrawals for legacy plants with once-through cooling systems are one to two orders of magnitude higher than for newer plants with recirculating cooling systems. Both the IGCC and NGCC generation have significantly reduced water intensity on both a withdrawal and consumptive basis than other major thermoelectric generation systems and have a potential for further reductions in water-intensity via the use of dry cooling systems.

Table 10.1 Water-intensity on a withdrawal and consumptive basis for thermoelectric generation using different sources of energy and using recirculating cooling systems

System	Water withdrawals		Water consumption		Chapter
	gal/MWh*	10^{-4} m³/MJ**	gal/MWh	10^{-4} m³/MJ	
Coal	500-1200	5.3-12.6	201-1189	5.0-11.6	4 & 9
IGCC	161-605	1.7-6.4	34-449	0.4-4.7	9
NG (Rankine/steam-turbine)	950-1460	10.0-15.4	662-1170	7.0-12.3	5
NGCC	150-283	1.6-3.0	130-300	1.4-3.2	5
Nuclear	793-2589	8.3-27.2	581-898	6.1-9.4	9
Concentrated Solar Power	740-1110	7.8-11.7	555-1902	5.8-20.0	9

Note: * English units of gallons per megawatt-hour; ** SI units of cubic meter per mega-joule.

Petroleum-derived fossil fuels represented over 95% of all transportation energy consumed in the U.S. in 2012. Gasoline (63%), diesel fuel (22%) and jet fuel (15%) are the most widely used types of petroleum-based transportation fuels. Biofuels contributed only 4.5% of the total energy consumed for transportation in 2012, the majority of which (4.1% of the total transportation energy) is ethanol blended into gasoline. A dependence on non-renewable fuels, concern about global warming, and a push for greater energy independence led to the introduction of the Renewable Fuel Standards (RFS), and later the Energy Independence and Security Act (EISA), which called for a reduction in annual petroleum consumption and an increase in the use of alternate fuels/biofuels such as ethanol and biodiesel. In 2012, ethanol constituted 94% of all biofuel produced in the U.S. on a volume basis, and was produced primarily from corn (the other sources being sugar cane and cellulose). Irrigation is the most significant source of water uptake and consumption for corn ethanol production and varies significantly from state to state. A mass- and energy- balance based model of ethanol refining presented in Chapter 6 estimated that 0.32 kg of ethanol, 0.33 kg of dry distiller grain (can be used as replacement for corn in livestock feed), and 2.72 kg of wastewater is produced per kg of corn and 2.68 kg of water raw material. The water used for cooking processes (~75%) exits the plant as water vapor but the water used for other processes (~25%) is usually recycled during ethanol production in modern facilities. Technology is available to build ethanol production plants that are capable of achieving zero water discharge, if necessary. Using lower quality surface or gray waters for ethanol production processes is also possible, which could play an important role in reducing the impact of ethanol processing in water-stressed regions. Research and development should continue in the areas of zero water discharge designs, the use of lower quality process water and the increased use of waste heat within ethanol production processes.

Table 10.2 Water-intensity on a withdrawal and consumptive basis for thermoelectric generation using different sources of energy and using once-through cooling systems*

System	Water withdrawals		Water consumption		Chapter
	gal/MWh#	10^{-4} m³/MJ ##	gal/MWh	10^{-4} m³/MJ	
Coal (once-through)	20,000-50,000	210.3-525.7	100-317	1.1-3.3	4 & 9
Natural gas (Rankine, once-through)	10,000-60,000	105.0-631.0	95-291	1.0-3.1	5
NGCC (once-through)	7,500-20,000	78.9-210.0	20-100	0.2-1.1	5 & 9
Nuclear (once-through)	25,000-60,000	262.8-630.8	100-400	1.1-4.2	9

Note: * - Once-through cooling systems represent legacy power plant designs. Future plant construction will use either recirculating, dry or hybrid wet-dry cooling systems.
- gallons per megawatt-hour; ## - cubic meter per mega-joule.

In addition to corn, other raw materials that can be used to produce ethanol include sugarcane, sorghum, beverage waste, cheese whey, cellulose and hemi-cellulose, corn stover, hardwood and switch grass. One potential drawback of using cellulose as a source of ethanol instead of corn is an increase in the amount of water required during processing to produce an equivalent amount of ethanol from the two sources. Cellulosic ethanol uses agricultural by-products and energy crops that can grow even in arid regions (Dale, 2007; Chiu *et al.*, 2009; Zink, 2007, Keeney, 2006), so a significant advantage of cellulosic ethanol is reduced water uptake and consumption due to a reduced need for irrigation. Use of agricultural by-products and cultivation of cellulosic energy crops can also potentially reduce competition between ethanol and food production.

There are a number of cooling steps within cellulosic ethanol production that result in water consumption through evaporation losses that need to be made up with fresh, recycled treated, or recycled carried-over water. It is possible to save water during ethanol production by recycling and reusing most of the wastewater as well as by taking steps to avoid evaporation losses. Additional technologies that can be used to minimize water usage from ethanol production include using pervaporation, which uses membrane separation to separate ethanol from water instead of steam distillation, membrane solvent extraction, which uses porous membranes to separate ethanol from the fermentation broth using an extracting solvent. Thermophilic yeasts can also be used to minimize the amount of cooling required for feed going into the fermentation unit and thus reduce cooling water usage.

Biodiesel, which is currently made primarily from transesterified soy oil in the U.S., is the second most common biofuel used in the U.S. In 2013, 46 out of the 50 states had biodiesel plants in operation. Irrigation is the most significant source of water uptake and consumption for biodiesel production and varies significantly from state to state. The water consumption study of biodiesel production detailed in Chapter 8 suggests that, on average, irrigation accounts for 61.78 gallons (gal) of water for a gallon of soybean biodiesel while soybean processing (0.17 gal/gal) and biodiesel production (0.31 gal/gal) stages consume much less. The total water consumption intensity for biodiesel processing was found to be 62.26 gal/gal, which is much lower than values reported in other existing literature. Chapter 8 of this report also investigated water consumption in potentially water-stressed areas. One recommendation for future work will be to characterize the inter-state trade of biofuel feedstocks and its impact on regional and state-level water resources since soy that is processed into biodiesel is a fungible commodity that can be transported for processing into biodiesel in locations far removed from where soy agriculture is occurring. To achieve this, robust data on soybean and soy oil trade across state boundaries is needed to fully account for the impact of irrigation water consumption on or regional biodiesel production.

Distiller grains are expected to become a major feedstock for post-2022 biodiesel production. In addition, algae is also considered a potential feedstock for biodiesel production. Water that can be used in algal biodiesel processes include open pond cultivation, harvesting and dewatering, algal oil extraction, and producing biodiesel via transesterification. While very large evaporative water losses occur during algal cultivation and in the harvesting and dewatering steps, dewatering is necessary to prevent carry-over of the algal biomass to the oil extraction step as it may prevent separation of lipids from algal cells. The extraction process involves solvent recovery, which requires make-up water for cooling towers and a boiler. Water consumption during the biodiesel production stage for algal biodiesel remains the same as that for soybeans. Overall, water consumption for the production of biodiesel from algae is much higher than the consumption for production of biofuels from soybeans, waste cooking oil, corn ethanol and cellulosic ethanol. Switching to saline and/or wastewater reuse may be necessary to alleviate concerns regarding the large quantities of freshwater use in algal biodiesel production. With technology improvements, low quality feedstocks, especially feedstocks from waste such as the trap grease from restaurants and sewer pipeline and other oil containing wastes, can be increasingly used for biodiesel production. Limitations of these feedstocks include the limited quantity, i.e., they will contribute to only a small fraction of the biodiesel supply, and they will require pretreatment to extract the oil fractions. A better understanding of the life cycle water needs for waste feedstocks will be necessary. The development of new processes to refine biological oils and fats into "renewable diesel fuel" has the potential to become a technology with high impact since it is a direct replacement for diesel and jet distillate fuels and thus represents a potentially higher market volume than for biodiesel blends with petroleum diesel fuel.

The amount of water consumed for producing ethanol and biodiesel from different fuel sources is listed in Table 10.3. For comparison purposes, the amount of water consumed to produce gasoline and diesel from petroleum is also listed.

Table 10.3 Water intensities on a consumptive basis for producing different types of biofuels

Fuel	Water used for Fuel Processing	Water used for Crop Irrigation or Petroleum Extraction
Gasoline	1 - 2.5	0
Ethanol (corn)	2.7 - 40 (13.4)[1]	15 - 934 (113)[1]
Ethanol (cellulose/switch grass + SRWC/corn stover)	12-17[2]	27 - 691 (28)[3]
Diesel Fuel Oil	1 - 2.5	0
Biodiesel (soy, current hydroxide TE)	0.3 - 0.5	1 - 1059 (62)[4]
Biodiesel (waste oil, acid-ester)	0.3	0
Biodiesel (algal, hydroxide TE)	1	40 - 1421 (554)[4]

Note: Water intensity in unit of gal H_2O/gal fuel or m^3 H_2O/m^3 fuel

[1] Approximate average value based on King and Webber, 2008

[2] Chapter 7 of this report

[3] Approximate average value based on Tidewell et al. 2011 projections for 2030

[4] Approximate average value based on literature discussed in Chapter 8 of this report.

As shown in table 10.3, ethanol processed from corn starch uses 2.7 – 40 gal water/gal ethanol, while ethanol processed from alternative sources such as cellulose, switch grass or corn stover uses 12-17 gal water/gal ethanol. The water-intensity for cellulosic ethanol processing falls approximately within the range of water-intensity for corn ethanol processing. This level of water usage is still high compared to gasoline or diesel processed from petroleum sources (1 – 2.5 gal water/gal fuel), and future research needs to focus on technologies to reduce water use during the fuel processing stage. In addition, as mentioned earlier, the amount of water required for irrigation purposes is often more than 2 orders of magnitude higher than the amount of water required to convert biomass to transportation fuel. Average water-intensities are shown in Table 10.3 for comparison purposes, but water-intensities for irrigation vary considerably on a regional basis. State and regional adaptive planning or the development of future water use models should carefully consider regional differences in irrigation water-intensity for biofuels. The water-intensities shown in Table 10.3 also do not take into consideration water lost by evapotranspiration. Development of state or even local evapotranspiration water intensities for biomass that are specific to U.S. cultivation should be a topic for future research.

Development of Federal policies that increase the use of ethanol, biodiesel and other biofuels in transportation fuels may be hampered by the water issues faced by communities in key agricultural regions of the U.S. unless biofuel feedstock cultivation is transitioned to less water-intensive biomass crops, e.g., transitioning ethanol production from corn starch to a cellulosic energy crops. For example, the cultivation of corn requires approximately 113 gallon-H_2O/gallon-ethanol on average compared to approximately 13 gallon-H_2O/gallon-ethanol required to convert corn to ethanol. Given that the majority of the corn grown in the U.S. is in the Midwest, and many areas rely mostly on groundwater for irrigation in states such as Iowa and Nebraska where groundwater levels are falling, it might not be sustainable for these states to maintain corn production to meet future ethanol demand. A potential alternative is to transition to less water-intensive biomass crops for the feedstock such as alternative corn varieties that use less water for irrigation, alternative sugar/starch crops or cellulosic feedstock such as switch grass. By 2022, EISA calls for the production of 16 billion gallons of ethanol from cellulosic feedstock while the production of corn-based ethanol is capped at 1 billion gallons, additional cellulosic material such as switch grass and short-rotation woody crops (SRWC) will need to be grown to meet the additional cellulosic ethanol demand. Switchgrass and SRWC are not considered to be agricultural residue, and thus would also require water for irrigation in some regions of the U.S. In 2006, 5,616 MGD of water was used for irrigating crops that were used to produce biofuel (primarily from corn). The amount of water required for conversion of the corn to biofuels was relatively lower at 94 MGD. It is predicted that the amount of irrigation water for feedstocks to produce approximately 15 billion gallons of corn-based ethanol and 80 billion gallons of cellulosic ethanol per year in the year 2030 would increase to 11,458 MGD of water (4649, 4077 and 2822 MGD for corn, switch grass and SRWC, respectively), while water used for conversion processes would require 470 MGD (219 and 251 MGD for corn and cellulosic ethanol, respectively). It is estimated that the irrigation water intensity to produce 80 billion gallons of cellulosic ethanol from switch grass and SRWC in 2030 would be approximately 28 gal water/gal cellulosic ethanol produced, which is still considerably lower than the irrigation water intensity to produce corn-based ethanol. Thus, shifting production from corn-based ethanol to cellulosic ethanol is expected to lead to significant reductions in the water intensity for irrigation of biomass crops. The irrigation water-intensity for cellulosic ethanol should also be considered a conservative estimate. The Tidwell et al. (2011) analysis of cellulosic ethanol water use was based upon a scenario with cellulosic ethanol production in 2030 that is more than double the entire RFS2 2022 volume for all renewable fuels, five-times the RFS2 volumes for cellulosic ethanol production, and is substantially higher than EIA projections. Such a high volume of production would result in considerable cellulosic biomass cultivation in regions that would require a relatively high degree of irrigation and thus a scenario using a more realistic scenario of approximately 16-20 billion gallons of cellulosic ethanol production may result in a reduction of irrigation water-intensity for cellulosic and should be the subject of future research in this area.

Due to prolonged droughts and population growth, there are concerns over water supplies to sustain food production, municipal water use, and energy production technologies that rely on water cooling and hydropower. Many demands and various consumers competing for water result in frequent over-allocation of water resources. To support the sustainability of water supplies, water conservation programs together with operationalized water activities, such as recycling and water reuse including water infrastructure adaptation and water policies, have been initiated. For example, the Southwest Nevada Water Authority (SNWA) employs a multi-faceted approach to reduce the drought exposure and create diverse and flexible water resources (SNWA, 2012). Their primary approaches to water resource management are implementing a water conservation program, treating and reusing wastewater, and extending water supplies.

Droughts have forced utilities in the Southwest to consider new cooling technologies and sources of water to cool thermoelectric plants (Walton, 2010). Several projects are exploring the potential use of non-traditional sources of process and cooling water. The use of wastewater for thermoelectric cooling is increasing in the Southwest although the supply of urban wastewater may be decreasing in some places due to conservation policies (Walton, 2010). Municipal wastewater still appears to be available in sufficient and reliable quantities to provide cooling for thermoelectric generation (U.S. DOE, 2010). Using reclaimed water for cooling systems has several advantages, as it helps to save potable water and provides a reliable supply. Water savings in thermoelectric plants can be achieved via air cooling, use of non-traditional water sources, recycling plant freshwater, and by increasing plant thermal efficiency (WNA, 2014). Other methods to reduce water consumption in cooling systems include the use of ice thermal storage within coal-fired cooling systems, which cools the intake-air to gas turbines, as well as the use of an air-cooled condensers (ACC). Furthermore, technologies such as Liquid Sorption Technologies, Flue Gas Sorption Membranes, and Condensing Heat Exchangers that can recover usable water from alternative sources, such as water from the flue gas emitted by coal-fired power plants, can also help reduce water consumption. Using dry cooling systems or hybrid cooling systems is possible in water-scarce regions where dry cooling may be feasible for certain plant configurations such as IGCC, NGCC, concentrated solar and geothermal generation. While a variety of technologies have been used to supplement or replace freshwater for cooling systems, there are some of limitations. For example, a dry cooling system can result in decreased power plant efficiency. Moreover, low quality impaired water can cause cooling system inefficiencies and a power plant site's proximity to wastewater sources may not be feasible.

Increasing energy demand in the coming decades is expected to aggravate competition for water and especially the availability of water used for electricity generation (U.S. DOE, 2008). Moreover, while renewable energy sources reduce the carbon-intensity of electric generation, some low-carbon intensity systems still heavily rely on water sources. Hydropower production, for example, is known to be sensitive to total runoff and to reservoir levels. IGCC plants need approximately one-third as much engineered cooling when compared with conventional coal thermoelectric plants (WNA, 2014). Concentrated solar generation systems have water requirements that are similar to other thermoelectric generation systems. Of the renewable forms of electric generation, two technologies, photovoltaic and wind, use the least amount of water for cooling.

Facilities can also consider saline water as a potential water source for cooling water and other uses. There is also potential for electricity dispatch be shifted via regional interconnects towards coastal areas due to their abundance of salt water sources for cooling water.

10.2 Recommendations and Future Work

Water, climate and energy issues are intricately and closely interrelated and cannot be adequately addressed in isolation. Increasing population and increased energy demand will result in increased competition between sectors for surface water. It is both inevitable and urgent to find alternative water resources to help offset increasing freshwater demand for thermoelectric cooling. Impaired waters and saline waters are potential alternative water sources that can help meet cooling needs of thermoelectric generation. There is already some experience in the U.S.

with the use of impaired waters for thermoelectric cooling, including the use of treated municipal wastewater and seawater.

One issue that has not been addressed in this report is the amount of energy required to transport and treat source water for power plant use as well as the energy required to treat wastewater from power plants. In addition, ways to conserve and reuse water in power plants should receive additional attention. A second issue that has not been addressed within this report is the use of waste biomass from secondary wastewater treatment processes to produce electricity (e.g., using microbial fuel cells), biofuels or methane gas, which can be used as a fuel source in wastewater treatment plants. In addition, the amount of water and energy required to produce fuel (coal, gas, oil, biofuels, etc.) in a form suitable for energy production nor the water and energy requirements for nuclear thermoelectric power generation have been fully addressed in this report and are topics for further investigation. In the case of biofuels, there are large data gaps in terms of missing irrigation water usage data, especially for certain types of feedstocks such as switch grass, algae, hard wood, etc., and for data that shows regional or state differences in the U.S. Since the amount of water required for irrigation far exceeds the amount of water required for biomass conversion to biofuels, future research should focus increasing on the size and scope of water monitoring networks for biomass cultivation, and improving modeling tools to estimate irrigation water usage.

Water usage data is readily available for coal-fired and natural gas-fired power plants, but there is an imbalance in data availability for other energy sources such as nuclear, solar, wind, hydroelectric and biomass. Life-cycle water use for generating electricity from renewable, low-carbon-intensity energy sources such as hydroelectric, solar, wind, biomass and geothermal systems should be studied in greater detail. In addition, since nuclear energy contributes a significant fraction of the electricity produced in the U.S., future studies should also conduct a detailed analysis of energy consumption, water withdrawal, and water consumption for nuclear power in conjunction with future analyses for coal and natural gas electric generation.

Climate change and regulations such as RFS, RFS2 and EISA mandate reductions in the use of petroleum-based fuels, and increases in alternative fuels such as the biofuels ethanol and biodiesel, which can be produced from multiple sources. Biofuels also have significant water requirements, especially at the cultivation stage. Some of the same water-conserving techniques used by the energy industry such as recycling process water or using treated municipal wastewater can also be used in the biofuel industry. Additionally, more research is needed to assess the regional and local water impacts of different types of electricity generation, and to analyze the water impacts of electricity-sector choices. More studies of viable energy resources and the impacts of geographical limitations may be useful in adapting the use of water locally in the energy generation sector. Finally, a review of the limitations of state and federal regulations on impaired water use, and a series of feasibilities study of technologies to facilitate the use of impaired water are recommended. Because of the linkages between water, energy and climate change, water-intensity on both a withdrawal and consumptive basis should also be integrated into regulatory models and analyses that characterize energy use and GHG emissions. Specific examples include detailed electric dispatch models such as the Integrated Planning Model (U.S. EPA, 2014) and detailed transportation fuel life cycle assessments such as the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (Argonne National Laboratory, 2013).

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