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DEVELOPING A GREENHOUSE GAS EMISSIONS CALCULATION TOOL FOR WATER UTILITIES

A Thesis
Presented to
the Graduate School of
Clemson University

In Partial Fulfillment
of the Requirements for the Degree
Master of Science
Environmental Engineering and Science

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by
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August 2012

Accepted by:
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David Ladner, Ph.D.

ABSTRACT

The issue of climate change has led to an increased emphasis on sustainable practices in almost every facet of our lives. For water utilities, this has increased scrutiny on energy use. Although traditionally viewed solely in financial terms, energy use is also the primary source of greenhouse gas (GHG) emissions from water utilities. The emerging concern over GHG emissions coincides with potential federal legislation and regulation by the Environmental Protection Agency (EPA). In order for water utilities to determine their GHG emissions, guides and tools must be made readily available. Information to educate water utilities about their GHG emissions is often scattered and calculation tools are not publically available for utilities in the United States.

The main objective of this research was to develop an accounting tool to facilitate water utilities in calculating their GHG emissions. This tool will allow a water utility to create a GHG emissions baseline and assist in meeting any emissions reduction goals. More specifically, this research project focused on four sub-objectives: (i) to create an Excel-based program to serve as the shell of the GHG emissions accounting tool, (ii) to develop energy prediction equations for different portions of the water production process, (iii) to include the water-energy nexus in the accounting tool, and (iv) to test the program using real data at various water utilities.

A thorough literature review was conducted to determine all available data and equations that pertained to the GHG emissions of water utilities. This information was used to create a GHG emissions accounting tool that was designed to be flexible enough for use by a wide range of utility sizes, treatment processes, and locations in the United

States. Energy prediction equations were developed for the raw water collection and finished water distribution phases of a water utility. A prediction equation for the treatment processes was not able to be developed with the current data set; therefore, literature data were utilized for energy prediction purposes in that phase. These prediction tools as well as a water-energy nexus evaluation were included in the program. The survey data obtained to form energy prediction equations had an average energy use of 3.1 kWh/1000 gallons.

The GHG emissions accounting tool was tested at seven water utilities in Georgia, North Carolina, and South Carolina. The average carbon inventory of the seven utilities was 1240 kg carbon dioxide equivalents (CO_2-eq.)/MG. Two of the utilities tested exceeded the EPA reporting rule threshold of 25,000 metric tons of CO_2-eq./yr. Assuming an average carbon inventory of 1240 kg CO_2-eq./MG, water utilities with a flow rate higher than 55.2 MGD would also exceed the reporting rule limit. These values vary greatly when utilizing different electrical grids. When using the highest and lowest GHG emitting EPA subregions, the seven utilities tested had an average carbon inventory ranging from 550 to 2190 kg CO_2-eq./MG. The flow rate required to exceed the EPA reporting rule threshold ranged from 31.3 to 123.5 MGD when using the previously stated carbon inventory averages. The main source of the GHG emissions within a utility is pumping because the raw water collection and finished water distribution phases can account for 75% of the carbon inventory. The carbon footprints of the seven utilities compared favorably to literature data. The main source for the carbon footprints of all seven utilities were Scope 2 (electricity-based) emissions, which accounted for at least

80% of the total emissions. The water-energy nexus evaluation showed that the water consumed in generating electricity for all seven water utilities was less than one percent of the total average production from each utility.

DEDICATION

To my future wife Nicole,

For providing the motivation to push through the hard times.

ACKNOWLEDGMENTS

I would first like to thank my research advisor, Dr. Tanju Karanfil, for all of the help and guidance he has lent to my work. I would also like to thank Dr. Cindy Lee and Dr. David Ladner for serving on my research committee as well as offering advice and instruction during my time at Clemson.

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Special thanks go to Mark Hahn, Bob Kenyon, Neal Spivey, Rick Bickerstaff, Jason Thompson, Jon Sherer, K.C. Price, Scott Banks, and Mike Bailes for allowing me to visit their water utilities and test the GHG emissions accounting tool.

Lastly, I would like to thank my family for all the support and understanding when times were busy.

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LIST OF ABBREVIATIONS

AwwaRF	American Water Works Association Research Foundation
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERWT	Ebro River Water Transfer
CH_4	Methane
CO_2	Carbon Dioxide
CO_2-eq.	Carbon Dioxide Equivalent
DAF	Dissolved Air Flotation
DFBETS	Difference in Beta
DFFITS	Difference in Fit
GAC	Granular Activated Carbon
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFC	Hydrofluorocarbon
hp	Horsepower
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kGD	Thousand Gallons per Day
LCA	Life Cycle Assessment
MGD	Million Gallons per Day
N_2O	Nitrous Oxide
NYSERDA	New York State Energy Research and Development Authority
PFC	Perfluorocarbon
RO	Reverse Osmosis
SAS	Statistical Analysis Systems
SQRT	Square Root
TOC	Total Organic Carbon
UKWIR	United Kingdom Water Industry Research
UNFCCC	United Nations Framework Convention on Climate Change
UV	Ultraviolet
VIF	Variance Inflation Factor

CHAPTER ONE

INTRODUCTION AND OBJECTIVES

The recent increased strain on potable water sources, as well as concern over environmental issues such as climate change, has led to an increased emphasis on sustainable practices (Vince, et al., 2008). These sustainable practices include areas such as energy use, which is of great concern in the water industry. In the United States, the water and wastewater industry uses 4% of the total electricity produced domestically (Goldstein & Smith, 2002). This amount makes the water and wastewater industry the third highest electricity consuming industry, behind the primary metal and chemical industries. At the level of an individual water utility, energy costs are second only to personnel in operation and maintenance budgets (Biehl & Inman, 2010). The amount of energy required to produce potable water is expected to increase due to degrading source water quality and increasingly strict regulations, both of which require more energy intensive treatment techniques (Goldstein & Smith, 2002).

The high costs associated with energy use have prompted studies among state and national organizations. The Energy Center of Wisconsin (Elliot, et al., 2003), California Energy Commission (Klein, et al., 2005), and New York State Energy Research and Development Authority (NYSERDA) (Malcolm Pirnie, 2008) have all investigated the energy use of water utilities in their respective states. These projects all aimed to present the average amount of energy used at water utilities of different sizes or source water types. An additional goal of each project was to review and report various ways to improve the energy efficiency of the water production process. In addition to state studies, national organizations such as the Electric Power Research Institute (EPRI) and the American Water Works Association Research Foundation (AwwaRF) have analyzed energy use at water utilities. The project by the EPRI (Goldstein & Smith, 2002) evaluated the electrical requirements of the water industry and also forecast the ability of the electrical generation sector to meet the growing needs of the industry. The project sponsored by the AwwaRF (Carlson & Walburger, 2007) had a similar goal as the state-related projects in evaluating the energy use of water utilities. The project also went into greater detail by producing energy benchmarking equations that water utilities could use to compare their energy use with those of their peers.

The energy use is not only a leading cost for a utility, but also the highest source of environmental impact over the life cycle of a utility (Vince, et al., 2008). Life cycle assessment (LCA) studies have arrived at three conclusions about the environmental impact of water production:

1. The operational phase of a water utility's life cycle is the overwhelmingly leading contributor (often > 90%) to environmental impact, while the construction and decommissioning phases can be neglected even in relatively extreme conditions of large infrastructure requirements (Raluy et al., 2005b).
2. Within the operational phase, energy use and more specifically, the production of electricity, is the greatest source of environmental impact (Vince, et al., 2008).
3. After energy use, the chemicals used during treatment represent the second largest source of environmental impact (Vince, et al., 2008).

While reducing energy use has traditionally been motivated by financial reasons, now it also ties into the growing environmental concern of climate change and greenhouse gas (GHG) emissions. The electricity required by water and wastewater utilities that uses 4% of the national electricity generation produces 31 million metric tons of carbon dioxide equivalents (CO_2-eq.) (Biehl & Inman, 2010). The GHG emissions from water utilities have an even greater impact on individual cities; as water production accounted for 31% of the total emissions from governmental operations in a study of 2006 data from Columbia, SC (Brennan, 2011). The relevance of GHG emissions is likely to increase as federal legislation in enacted such as the American Clean Energy and Securities Act (ACES) (American Clean Energy and Security Act of 2009, 2009). The ACES, also known as the Waxman-Markey Bill, passed the House of Representatives in 2009 and contained sections forming a cap and trade system for carbon emissions. The bill was never voted on by the Senate and because the session of Congress in which it was introduced has ended; the bill must be reintroduced to a new session of Congress (H.R. 2454 - 111th Congress: American Clean Energy and Security Act of 2009, 2009). The United States Environmental Protection Agency (EPA) has recently begun a process of GHG regulation by passing a reporting rule. The rule requires annual GHG emission reporting by entities that emit greater than 25,000 metric tons of CO_2-eq. per year (Hoffman, 2010). This rule includes industries such as power production, petroleum refineries, chemical production, and solid waste landfills but currently omits water utilities.

Some water utilities have an interest in reducing GHG emissions and the effects of climate change that are not regulatory based. Climate change can have a drastic impact on the water utility's source waters. For example, the Western United States are already seeing a 10% decrease in water runoff from snowmelt between April and July, which translates to less water to fill reservoirs (Wallis, et al., 2008). Climate change is also leading to sea level rise along with longer and more frequent heat waves (Wallis, et al., 2008). Overall, climate change is decreasing both the quantity and quality of source waters available to water utilities while increasing the demand for potable water that comes with increasing temperature (Wallis, et al., 2008).

In order for a water utility to evaluate its GHG emissions, proper guides and tools must be made available. While guides are available to assist water utilities in determining their GHG emissions, the information is often scattered and has not been compiled and made readily available to water utilities in a simple and user friendly way. In addition, GHG accounting tools are mostly developed for general use or are geared toward a specific industry, such as chemical production. One commercial tool designed specifically for water utilities was created by the United Kingdom Water Industry Research (UKWIR). This tool is designed for water utilities in the United Kingdom and its newest version costs about $400 (UKWIR, 2010). Other tools may have been developed by consulting companies or large utilities but are not commercially or publically available.

An additional topic being raised in the discussion of climate change and sustainable practices is the water-energy nexus. The water-energy nexus involves the concept that energy is required to produce water, yet at the same time water is required to produce energy (Glassman, et al., 2011). This concept becomes increasingly important when analyzing electricity production methods, in that GHG emissions as well as the water consumed in generating the electricity need to be taken into account.

The main objective of this thesis project was to develop an accounting tool that will allow water utilities to calculate their GHG emissions. Using this tool, utilities will be able to assess their carbon inventory and footprint and their impact on climate change. It will facilitate the creation of an emissions baseline and assist in meeting any emissions reduction goals. The tool will also become beneficial should a mandated GHG emissions reporting rule or reduction program apply to water utilities. To accomplish the main objective, this research project focused on the following four sub-objectives:

The first sub-objective was to create an Excel-based program to serve as the shell of the GHG accounting tool. Prior to developing the program, a comprehensive literature review was conducted to compile all available data, equations, and other useful information related to the GHG emissions of water utilities. For the program itself, Excel was chosen because it is a common, widely used tool that can be used by people with a wide range of computer experience. The Excel program contains all the necessary data entry locations along with the formulas and data needed to determine the GHG emissions.

The second sub-objective was to develop energy prediction equations for different portions of the water production process. Energy use has been shown to be the major contributor to GHG emissions for water production, so it was important to provide a way to determine that information if not know to the water utility. Energy use predictions were to be developed for three portions of water production: (i) raw water collection, (ii) treatment, and (iii) finished water distribution. To construct these equations, data on energy use and system characteristics were obtained using surveys conducted by others as well as the author of this thesis.

The third sub-objective was to include the water-energy nexus in the GHG accounting tool. The amount of electricity used at a given utility was used to determine the amount of water consumed in producing that electricity. That water consumption was then utilized to determine a net water production value for the utility.

The fourth sub-objective was to test the program using real data at various water utilities. This process served two functions. The first was to gather an idea of the scale of GHG emissions associated with a variety of water utilities. The second function was to obtain feedback about the program from its intended users.

CHAPTER TWO

LITERATURE REVIEW

In this chapter, the energy use investigations made on a national and statewide scale will be discussed, especially as they pertain to predicting energy use throughout water production. In addition, the environmental impact from water treatment as evaluated by life cycle assessments (LCAs) will be discussed. The topic of GHG emissions will also be introduced and will include what they are, how they are measured, the concept of GHG accounting, the current tools available to perform the accounting, and GHG regulations. The issues stemming from the water-energy nexus will also be discussed. The chapter will conclude with a summary of findings.

2.1 Energy Use Investigations

Because energy use is the dominant source of environmental impact as well as a major financial driver, a number of state agencies have investigated energy use involved in water production. Most projects have had the goals of quantifying the energy used during water production and reviewing energy savings measures in order to decrease costs.

One such investigation was organized by the Energy Center of Wisconsin (Elliott, et al., 2003) in order to quantify the energy used at the state's drinking water facilities. The study evaluated Wisconsin's drinking water facilities from 1997 to 2000 and determined that the statewide average energy use was 1.6 kWh per 1000 gallons of water produced. The results of the study illustrated that economies of scale applied to energy use as the largest facilities used the least amount of energy per 1000 gallons (see Table 2.1). The study also determined differences in energy use between groundwater and surface water sources, with groundwater sources requiring 1.3% more energy per gallon. Another topic of investigation was the effect of implementing new technologies. These results are presented in Table 2.2.

Table 2.1 Median energy use values for drinking water facilities in Wisconsin [adapted from (Elliott, et al., 2003)].

Utility Class	Number of Customers	Median Energy Use (kWh/1000 gal)
AB	> 4,000	1.51
C	1,000 – 4,000	1.85
D	< 1,000	1.89

Table 2.2 Energy increases due to new technology implementation [adapted from (Elliott, et al., 2003)].

Treatment Process	Energy Addition (kWh/1000 gallons)
Ozone Disinfection	0.12 – 0.55
UV (low-pressure)	0.0032 – 0.0048
UV (medium-pressure)	0.0068
Microfiltration	0.0 – 0.7
Ultrafiltration	Not Enough Data

The background research performed for the study on drinking water facilities in Wisconsin (Elliott, et al., 2003) located data detailing the energy requirements of specific steps in the water production process. The data pertaining to surface water plants can be seen in Table 2.3 while companion data for groundwater plants are presented in Table 2.4. An attempt was made to obtain a copy of the report, published by the EPRI, containing the original data, but was unsuccessful. The data are reported to be from the 1970s and thus caution is urged when using. The totals given represent the energy requirements of an entire water production process. If the values are converted from units of kWh/day to kWh/1000 gallons, a comparison can be made between these literature values and the data obtained in the study of Wisconsin drinking water facilities. Those converted values can be seen in Table 2.5. The literature values do not illustrate as dramatic of an effect of economies of scale as the results of the study indicate, especially with groundwater plants which remain constant from 1 MGD to 20 MGD. The values do compare favorably to the average values shown in Table 2.1.

Table 2.3 Energy requirements (kWh/day) for process steps in surface water treatment (Elliott, et al., 2003).

	Treatment Plant Production					
Process Step	1 MGD	5 MGD	10 MGD	20 MGD	50 MGD	100 MGD
Raw Water Pumping	121	602	1205	2410	6027	12055
Rapid Mixing	41	176	308	616	1540	3080
Flocculation	10	51	90	181	452	904
Sedimentation	14	44	88	175	438	876
Alum Feed System	9	10	10	20	40	80
Polymer Feed System	47	47	47	47	47	47
Lime Feed System	9	11	12	13	15	16
Filter Surface Wash Pumps	8	40	77	153	383	767
Backwash Water Pumps	13	62	123	246	657	1288
Treated Water Pumping	1205	6027	12055	24110	60273	120548
Chlorination	2	2	2	2	4	8
Residuals Pumping	4	20	40	80	200	400
Thickened Solids Pumping	N/A	N/A	N/A	123	308	616
Total	1483	7092	14057	28176	70384	140685

Table 2.4 Energy requirements (kWh/day) for process steps in groundwater treatment (Elliott, et al., 2003).

	Treatment Plant Production			
Process Step	1 MGD	5 MGD	10 MGD	20 MGD
Well Pumping	605	3025	6050	12100
Chlorination	9	45	93	186
Booster Pumping	1210	6050	12100	24200
Total	1824	9120	18243	36486

Table 2.5 Energy requirements (kWh/1000 gal) for the entire water production process [adapted from (Elliott, et al., 2003)].

	Treatment Plant Production					
Water Source	1 MGD	5 MGD	10 MGD	20 MGD	50 MGD	100 MGD
Surface Water	1.48	1.42	1.41	1.41	1.41	1.41
Groundwater	1.82	1.82	1.82	1.82	N/A	N/A

Another project undertaken to evaluate energy use in water production was carried out by the California Energy Commission (Klein, et al., 2005). The project was developed to study the relationship between energy production and water and wastewater utilities in California as well as identify solutions to the water and energy problems of the state. The report provides overall energy intensity ranges for the three main phases of water production (Table 2.6). The large range of values can be attributed to the unique combination of resource and population locations found in California. Northern California is home to only one-third of the population of the state, yet it receives two-thirds of its precipitation. This situation causes Southern California to import about half of its raw water from significant distances, such as the Colorado River. To gain a better perspective on the differing amounts of energy required to produce water in the state, Table 2.7 illustrates the differences between the energy use for water production in Northern and Southern California. The total energy required for water production in Northern California, 1.45 kWh/1000 gal, is similar to values seen in the Wisconsin study (Elliott, et al., 2003). However, the result of having to pump raw water from increased distances is evident in Southern California, having an energy intensity seven times greater than the northern portion of the state.

Table 2.6 Energy use ranges for water production in California [adapted from (Klein, et al., 2005)].

	Energy Use (kWh/1000 gal)	
Process Step	Low	High
Water Supply and Conveyance	0	14
Water Treatment	0.1	16
Water Distribution	0.7	1.2
Total	0.8	31

Table 2.7 Energy use for typical urban water systems in Northern and Southern California [adapted from (Klein, et al., 2005)].

	Energy Use (kWh/1000 gal)	
Process Step	Northern California	Southern California
Water Supply and Conveyance	0.15	8.9
Water Treatment	0.1	0.1
Water Distribution	1.2	1.2
Total	1.45	10.2

Another state interested in evaluating its energy use for water production was New York. The New York State Energy Research and Development Authority

(NYSERDA) published a report detailing the findings of the study (Malcolm Pirnie, 2008). The study was initiated to examine the possible increases in energy efficiency in the water and wastewater industry in the state. To achieve that goal, an energy baseline was to be evaluated, thus determining average energy use values for water production. The report states that the national average for water production is 1.4 kWh/1000 gal, which corresponds well to values found previously. The energy requirements for water production in New York are shown in Table 2.8. The large population and ability to treat without filtration allows some New York City water treatment plants to use relatively low energy intensities. This is especially evident when comparing the statewide average energy use with and without the New York City systems. Even when omitting the low energy intensity New York City systems, the New York state water systems are able to produce water at lower energy intensities than the national average. The report states that the reasons for this lower energy use are water sources close to major populations, large quantities of easily treatable surface waters, and fairly shallow groundwater sources. The data also illustrate that economies of scale apply to the water systems in New York, with the larger systems using less energy per volume of water produced.

Table 2.8 Energy use for New York water systems serving various population sizes [adapted from (Malcolm Pirnie, 2008)].

Population Served	Energy Use with New York City (kWh/1000 gal)	Energy Use without New York City (kWh/1000 gal)
Statewide Average	0.705	0.890
< 3,300	1.080	1.080
3,300 – 50,000	0.980	0.980
50,000 – 100,000	0.810	0.810
> 100,000	0.600	0.640

The New York report (Malcolm Pirnie, 2008) also investigated the energy required to produce water from different sources (Figure 2.1). The figure helps to illustrate the economies of scale effect for surface water and purchased water sources. However, water production utilizing groundwater does not appear to follow the economies of scale effect in New York. While the cause of this trend is not presented, it may be because increasing groundwater flows often requires new wells, and therefore completely new pumps; while to increase flow from a surface water source, only a larger pump is required. For purchased water sources the water is provided at pressure already by the seller, so increasing flow would involve a larger pump to send the influent water to the beginning of the treatment process. The report closes by discussing factors that may affect energy use in the future. Increasingly strict regulations which correspond to more energy intensive treatment techniques (ozone, ultraviolet (UV) disinfection, and membrane filtration) are pointed out as the most likely cause of increased energy use.

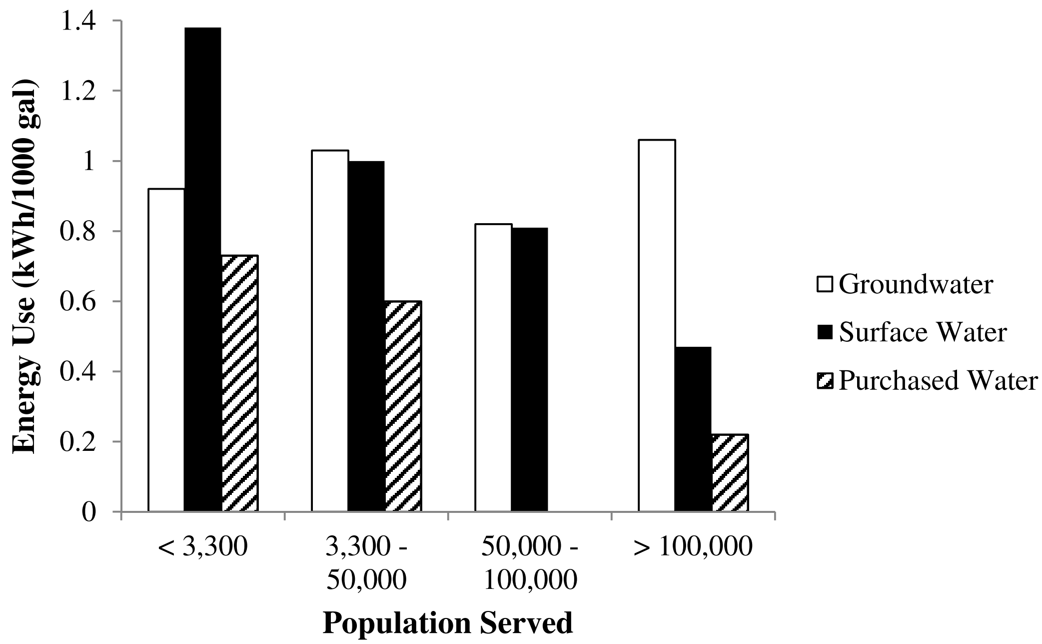

Figure 2.1 Evaluation of energy requirements for different source waters among various sizes of New York water systems (adapted from (Malcolm Pirnie, 2008)).

In addition to state investigations, national organizations have also conducted studies on energy use in drinking water production. The Water Research Foundation sponsored and published a report (Veerapaneni, et al., 2011) to examine the energy use at desalination facilities. Due to the dwindling supply of fresh water sources and the increasing demand for potable water, desalination is seen as an opportunity to provide previously untapped sources of water. While the process is energy intensive, the worldwide water production capacity using desalination technologies was estimated to be 15,000 million gallons per day (MGD) in 2010. The goal of the study was to evaluate the energy use of different desalination technologies and to recommend ways to improve the energy efficiency at desalination plants. The study achieved its goal through surveys and site visits to desalination facilities. The main desalination processes evaluated were reverse osmosis (RO), multiple effect distillation, and multi-stage flash. RO has become the more desired process in the past decade, with 55% of new seawater desalination plants utilizing this technology (Veerapaneni, et al., 2011). Membrane processes are used exclusively when treating brackish water and wastewater sources, most likely because energy use decreases with decreasing salinity of the source water, while the energy use of a thermal process (multiple effect distillation and multi-stage flash) remains constant.

The study was able to compile overall averages for energy use at desalination plants around the world. The advantage in energy use for RO processes over thermal processes was evident. Thermal processes average between 20 and 45 kWh/1000 gallons while RO processes treating seawater average 12 to 17 kWh/1000 gallons. The report also details the energy use for "large seawater desalination facilities" as ranging from 16 to 24 kWh/1000 gallons, while those built in the last five years range from 14 to 16.5 kWh/1000 gallons (Veerapaneni, et al., 2011). The reasons are unclear for the differences in the stated RO energy use values. One would assume that larger plants would use less energy because of economies of scale effects, but that does not seem to be the case. The energy used in the different steps in the RO treatment process was determined in the study as well and is located in Table 2.9. The energy consumed in the RO treatment step, both first and second pass, accounts for the vast majority of the energy required to produce potable water and ranges from 60-86%. In absolute numbers, the first pass uses 9 to 11.5 kWh/1000 gallons while the second pass uses 1 to 2 kWh/1000 gallons (Veerapaneni, et al., 2011). The high amounts of energy required for

RO are illustrated with these numbers as the second pass of the RO process alone requires about as much energy as is consumed in the entire water production process at a conventional water treatment plant in Wisconsin (Elliott, et al., 2003) and New York (Malcolm Pirnie, 2008).

Table 2.9 The relative amount of energy used by the various steps in the desalination process [adapted from (Veerapaneni, et al., 2011)].

Treatment Phase	Percentage of Total Energy Use
Raw Water Collection	5-10%
Pretreatment	5%
1^{st} Pass RO	50-66%
2^{nd} Pass RO	10-20%
Finished Water Distribution	5-10%

The desalination report (Veerapaneni, et al., 2011) also investigated the energy required for treatment of brackish waters and wastewater. The energy required at these facilities ranges from 1 to 8.6 kWh/1000 gallons. The salinity of the source water has a significant impact on the energy required for treatment with 1.5 to 3.5 kWh/1000 gallons needed for source water salinity ranging from 1000 to 2000 mg/L.

The report (Veerapaneni, et al., 2011) also included an energy use comparison between various individual water treatment steps, which can be seen in Figure 2.2. The plot illustrates the increased energy intensity of advanced technologies, such as RO, versus traditional techniques such as rapid mixing, flocculation, and sedimentation.

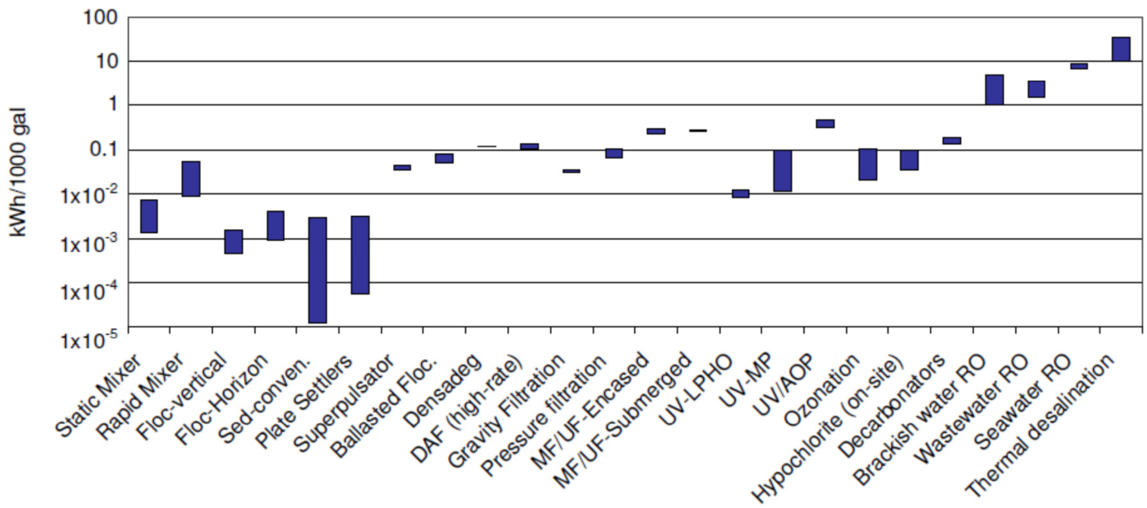

Figure 2.2 Energy requirements of various steps in the water treatment process (Veerapaneni, et al., 2011).

The reports on energy use for water production reviewed so far have focused on presenting overall averages, stated as kWh/1000 gallons for the entire water production process, along with suggestions for energy efficiency improvements. While overall averages are helpful in presenting an order of magnitude range of energy use, they provide little assistance in predicting the energy use at a specific water utility. The reports studying energy use in Wisconsin water treatment facilities (Elliott, et al., 2003) and in desalination facilities (Veerapaneni, et al., 2011) provide greater details for the energy required during water treatment but few details are presented for the raw water collection and finished water distribution portions of water production. A project sponsored by the AwwaRF (Carlson & Walburger, 2007) provides the most detailed evaluation of energy use at water utilities to date. The stated goal of the project was to develop tools to allow for comparison of energy use among peers in the water and wastewater treatment industries.

The first step for the AwwaRF project (Carlson & Walburger, 2007) was to conduct a mail survey to assess the characteristics and energy use of various water utilities. A similar project being undertaken by the NYSERDA (Malcolm Pirnie, 2008) was discovered by the AwwaRF report team, and in order to prevent multiple surveys from being mailed to utilities in New York, a joint survey was constructed. This action resulted in a slight duplication of the two reports and a disproportional amount of data from New York utilities. Overall, the project mailed surveys designed to obtain a detailed summary of the water production process along with energy usage to 1,723 utilities. Responses were received from 217 utilities, providing a 13% response rate. The report provides a number of figures depicting the distributions based on energy cost, energy use, daily flow, etc.

The report (Carlson & Walburger, 2007) then discusses the development of a water metric to be used to compare water utilities to their peers. The metric was to predict energy use for the entire water utility from a set of system parameters. The first step was to remove utilities with electricity uses less than 2,000 kWh and greater than 5,000 kWh/MG; these steps eliminated eight utilities. When contemplating the type of model to use, a logarithmic transformation of the data was selected due to the large range of the data set. It is unclear whether another transformation, such as a square root, was investigated to account for the large range or if a logarithmic transformation was the only one considered. The metric was then built by using the natural log of energy use as the dependent variable. First, a simple model consisting of the natural log of the daily average flow as the independent variable was shown to illustrate a linear relationship with the natural log of energy use. From that basic model, the metric was expanded in a stepwise manner. Each survey parameter was then evaluated one by one to determine which had the greatest significance, as gauged by a t-test, when added to the model. The parameter with the highest significance was then added to the model. This process was repeated until the entire model was formed. During the model formation, variables were only considered for the next iteration if they had a t-test value greater than 2 in the previous step. The final model for predicting the total energy use for water production was as follows:

$$
\begin{aligned}
&LN(Energy\ Use\ [kBtu/yr]) \\
&\quad = 8.2394 + 0.4993 * LN(Total\ System\ Flow\ [kGD]) - 0.0630 \\
&\quad * LN(Purchased\ Water\ Flow[kGD] + 1) + 0.3724 \\
&\quad * LN(Total\ Pumping\ Horsepower) + 0.0620 \\
&\quad * LN(Production\ Pumping\ Horsepower + 1) + 0.2385 \\
&\quad * LN(Distribution\ Main\ Length[miles]) + 0.0991 \\
&\quad * LN(Distribution\ System\ Elevation\ Change[ft])
\end{aligned} \tag{1}
$$

This model has an R^2 value of 0.878 and plots of the residuals illustrate that they are randomly distributed. The model is designed to calculate the average energy use of a water utility with the given characteristics. A comparison between the energy use of a given utility and those of its peers is accomplished by comparing the actual energy use of the water utility with the value predicted using the model. If the amount of energy used is lower than the amount predicted by the model, the water utility uses less energy than its average peer. To gauge how much better or worse a utility is performing versus its peers, a scoring system was created based on an energy use distribution curve. This system gauges the energy use of a water utility based on a percentile system, thus providing a 1 to 100 grade, with 100 being the best performer in terms of energy use. The report also presented a ten parameter model that excluded pumping horsepower (hp); however, this model seemed to be less accurate than the six parameter model despite the additional variables.

The arguments presented in a paper by Flom and Cassell (2009) illustrate that the steps taken in the model selection process in the AwwaRF study may have led to a false confidence about the accuracy of the model. While no rationale was presented in the AwwaRF report (Carlson & Walburger, 2007) to explain the choice of selection method, the energy prediction model was created using a specific type of a stepwise selection technique called forward selection. In this method, no variables are set in the beginning of the process. Variables are then added one at a time by means of whichever variable has the greatest value of a given significance test. The model is complete when none of the remaining variables meet the given significance threshold. This type of model formation process, along with other stepwise techniques, results in a number of errors that are problematic to identify and correct. Some of these include high R^2 values, low error values, low p values; the estimates of the independent variable parameters are high in absolute value, and the models formed are often too complicated. The errors in the forward selection process all lead the user to overestimate the accuracy of the model. Instead of using a stepwise selection technique, other options are available and could be used such as the shrinking method called lasso, which was selected for this study and to be discussed later.

The AwwaRF-sponsored study (Carlson & Walburger, 2007) also discussed the energy use in the different sections of water production. Energy use prediction equations were developed for the raw water collection (called production in the report), treatment, and distribution portions of a utility and were formed in an identical way as the overall energy use equation. While the method used to determine the prediction equations may not be ideal, the identifying factors chosen for each equation can be helpful in building future models. For the raw water collection phase, the significant variables were determined to be total flow rate, raw water collection pumping horsepower, and purchased flow rate. The equation describing water treatment utilizes total flow rate, purchased water flow rate, raw water collection pumping horsepower along with the treatment steps of oxidation, direct filtration, sand drying bed, iron removal, and ozonation. For the distribution phase, the selected variables include total flow rate, distribution pumping horsepower, elevation change, and the presence of lagoon dewatering, pressure filtration, and gravity thickening. It is unclear why processes in the treatment phase were included in the model for distribution energy use.

2.2 Life Cycle Assessment Studies on Water Treatment

One tool that has been developed to assist in evaluating the environmental impact, and therefore the sustainable nature, of various processes is life cycle assessment (LCA). An LCA involves what is commonly referred to as a cradle-to-grave approach where the entire life cycle of a process is taken into account including all the inputs and outputs of the process. A more detailed description of the tool and the steps required to perform such an analysis can be found in the International Organization for Standardization (ISO)

14040 document, as well as its companion files (International Organization for Standardization, 2000, 2002, 2003, 2006a, 2006b).

LCA is utilized by Friedrich (2002) to compare two different methods of water production, a conventional treatment system and a membrane filtration system. The assessment showed that the operational phase of water production is dominant in terms of environmental impact over the construction and decommissioning phases. The operational phase of both treatment techniques consumes 96-99% of the mass and energy used over the life cycle of the production facilities. Within the operational phase, the generation of electricity needed to power the water production is the main source of the environmental impact.

Another example of LCA involves a two part study, first comparing the environmental impact of three different desalination techniques (Raluy et al., 2005a), and second comparing those results to a river water transfer project (Raluy et al., 2005b). The first study investigates the environmental impact of RO, multi effect desalination, and multi stage flash. This analysis confirmed the results of the previous study that the operational phase accounts for the majority of the environmental impacts for each of the desalination technologies. While one environmental impact assessment method resulted in the operational phase accounting for 88.6% of the environmental impacts, the other methods fell in the 96-99% range. The impacts of the final disposal phase were found to be negligible, making the remaining portion due to the construction phase (Raluy et al., 2005a). The second part of the study compared the process from part 1 that had the lowest environmental impact, RO, with the Ebro River Water Transfer (ERWT) project.

This project involves a 900 km long system of mostly open water conduits and is an example of an extreme case with a large infrastructure in place. The LCA of the ERWT resulted in the operational phase accounting for an average of 85% of the environmental impact if the lifespan of the ERWT was assumed to be 50 years. However, if the lifespan of the ERWT was assumed to be 25 years, the operational phase would account for 75% with the construction phase accounting for 25% (Raluy et al., 2005b). This study illustrates that even when dealing with an extreme example, a substantial infrastructure with a short lifespan, the operational phase still dominates the environmental impact of water production.

Stokes and Horvath (2006) and Lyons et al. (2009) utilized LCA to compare the environmental impact from three different water supply methods: importation, reclamation/recycling, and desalination. Stokes and Horvath (2006) found that desalination caused the greatest impact because it also required the highest energy use, thus illustrating that energy use is the most important factor in environmental impacts from water production. Lyons et al. (2009) determined similar results in that desalination had the greatest impact due to its high energy use. The study also confirmed that the operational phase is responsible for the majority of the environmental impacts, even when the infrastructure life span was reduced from 50 to 10 years. Due to the high importance of energy use, Lyons et al. (2009) investigated how the environmental impacts would change when using energy grids made up of different electrical production methods. Three energy grids were chosen for evaluation: United States (predominantly fossil fuels), France (predominantly nuclear), and Norway (predominantly hydroelectric).

Order of magnitude changes in environmental impacts were illustrated when changing from the United States grid to the France grid and then onto the Norway grid. This exercise helps to demonstrate the importance of using an accurate energy grid when evaluating environmental impact. The data also show that changing the electrical generation methods to more sustainable options can provide large decreases in environmental impacts.

Vince et al. (2008) evaluated multiple water treatment processes and also determined that energy use was the primary cause of environmental impacts. The study established that the second highest cause of environmental impacts was from production of the chemicals used in the treatment process. Vince et al. (2008) concluded that the high energy requirements of water production, especially for the raw and finished water pumping, result in energy use being a significant gauge of environmental impact.

2.3 Importance of the Electrical Grid

The electrical grid which a water utility is using becomes critical when evaluating the GHG emissions of that utility. This was demonstrated by Lyons et al. (2009) and is also illustrated in Figure 2.3. There exists a clear separation between the traditional thermal processes (coal, gas, and oil) and nuclear and the renewable sources (hydroelectric, biomass, wind, and solar). A water utility that is able to draw power from an electrical grid using more renewable sources will automatically be responsible for less GHG emissions than a comparable utility using a grid composed of more thermal processes.

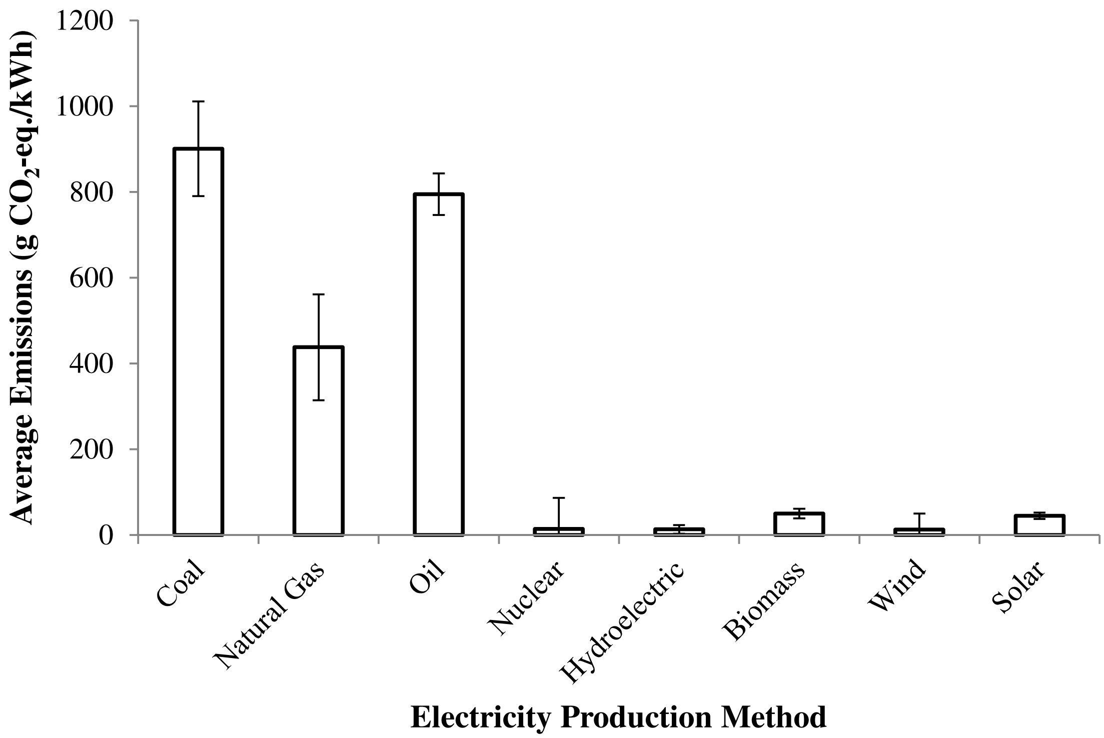

Figure 2.3 Average life cycle GHG emissions from various electricity production methods (data sources can be seen in Appendix A).

2.4 Greenhouse Gases

A GHG is a compound that absorbs thermal radiation, thus trapping heat on the surface of the Earth and causing a greenhouse effect (IPCC, 2007). When reporting GHG emissions, there are six gases or categories of gases that are considered. These six were recognized by the United Nations Framework Convention on Climate Change (UNFCCC) in the Kyoto Protocol (Huxley, Bellamy, Sathyanarayan, Ridens, & Mack, 2009).

1. Carbon Dioxide (CO_2)
2. Methane (CH_4)
3. Nitrous Oxide (N_2O)

4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur Hexafluoride (SF_6)

These six represent stable compounds that can remain in the atmosphere for centuries, making them long-lived GHGs. These long-lived GHGs are reported because they have a significant impact on the climate due to their persistence (Forster et al., 2007). When evaluating the emissions of water utilities, the specific GHGs of interest are CO_2, CH_4, and N_2O. If emissions from refrigerants are a concern, HFCs and PFCs can become a factor (Huxley, et al., 2009).

2.5 GHG Measurements

The unit of measurement for GHGs is carbon dioxide equivalents (CO_2-eqs.). To convert the amount of an individual GHG to CO_2-eq., the global warming potential (GWP) of that particular GHG is used. The GWP of a certain GHG denotes how much heat that particular GHG can trap relative to CO_2. When reporting GHG emissions, a GWP referenced over a 100 year timeframe is used (Huxley, et al., 2009). The GWP for the GHGs important to water utilities are given in Table 2.10. If a process emitted 1 kg of CH_4, that would be the equivalent of emitting 25 kg of CO_2 in terms of GWP.

Table 2.10 GWP values for various GHGs [adapted from (Forster, et al., 2007)].

Common Name	Chemical Formula	GWP_{100}
Carbon Dioxide	CO_2	1
Methane	CH_4	25
Nitrous Oxide	N_2O	298

2.6 GHG Accounting Principles

When accounting for GHG emissions, three categories have been established to identify the source of the emissions (Huxley, et al., 2009). These categories are known as Scope 1, Scope 2, and Scope 3. A visual of what each category includes can be seen in Figure 2.4. Scope 1 represents direct emission sources and is described as those sources that are owned or controlled by the organization, in this case, the water utility. Scope 1 emissions can also be broken down into the following subsets:

1. Stationary Combustion Sources
2. Mobile Combustion Sources
3. Process-Related Emission Sources
4. Fugitive Emission Sources

Stationary combustion sources would include items such as stationary back-up generators and natural gas-fueled equipment. A common type of mobile combustion source is any utility owned vehicle, such as a maintenance truck. Process-related emission sources would include emissions from treatment plant processes with the exception of the combustion of fuel. For a water utility, this could include ozone generation and granular activated carbon (GAC) regeneration. Fugitive emission sources are categorized as stationary source emissions not occurring from an exhaust pipe or stack. These sources can include natural gas pipeline leaks and refrigerant system leaks (Huxley, et al., 2009).

Scope 2 represents sources of indirect emissions. These emissions are caused by the production of the electricity, steam, and hot or chilled water which are used by the water utility. These sources must be located outside of the boundary of the utility; if not, they would be counted as Scope 1 emissions (Huxley, et al., 2009).

Scope 3 accounts for any other indirect emission sources. Scope 3 is described as optional indirect emission sources because often the water utility must decide on which sources to include. These indirect emission sources can include any source that the utility has measureable amount of control over. Common Scope 3 emission sources are employee commuting and business travel. An example more closely relate to water utilities is the emissions associated with the production and transport of chemicals used at the treatment plant (Huxley, et al., 2009).

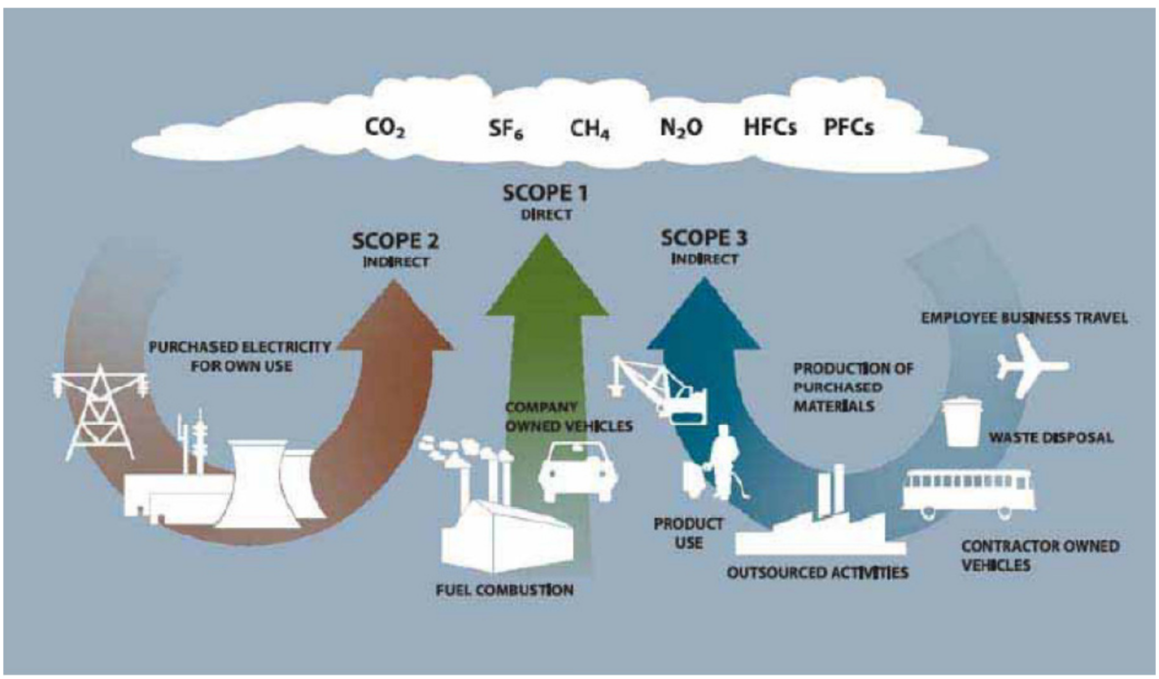

Figure 2.4 Representation of GHG emission source categories (Huxley, et al., 2009)

Two common terms used when reporting GHG emissions are carbon footprint and carbon inventory. These terms are sometimes considered interchangeable; however, they are not synonyms. A carbon inventory represents the sum of GHG emissions from

Scopes 1 and 2, while a carbon footprint encompasses all three. This results in the carbon footprint of an organization usually becoming larger than its carbon inventory.

Another important principle of GHG emissions accounting is establishing proper boundaries. Two approaches have been developed to select what GHG emissions should be included within a given boundary. The equity share method involves reporting the emissions based on what percentage of the source of emissions is owned by the water utility. The control method reports all of the GHG emissions from a source under the control of the water utility. The water utility can financially or operationally control a source of emissions. An example of an emission source that may require these decisions is a maintenance truck owned by a town but used by the water utility. Under the equity share approach, the emissions associated with the truck would be reported by the town and not the utility. Under the control approach, the emissions by the truck would be reported by the utility because it has operational control over the vehicle (Huxley, et al., 2009).

2.7 Existing GHG Accounting Tools

There are a number of existing instructions on how to quantify and report GHG emissions, some of which also include tools to assist in such quantification. Many of these are described by Huxley et al. (2009) and are not developed for specific industries, but as an overall guide. One specific website that offers valuable emissions accounting tools is *www.ghgprotocol.org (The Greenhouse Gas Protocol, 2011)*. The site offers tools for emissions from general sources such as stationary combustion and refrigeration/air conditioning, as well as specific sector tools for industries such as aluminum and cement. The only tool designed specifically for water utilities was created by the United Kingdom Water Industry Research (UKWIR). This tool is designed for water utilities in the United Kingdom and its newest version costs about $400 (UKWIR, 2010). There are no GHG emissions accounting tools designed for water utilities in the United States, let alone ones that are publically available. The only publically available tool somewhat related to this area was developed by a Clemson University graduate student for conventional wastewater treatment plants (Hicks, 2010).

2.8 GHG Regulations

2.8.1 Kyoto Protocol

The first action to take place on the subject of GHG emissions was the UNFCCC, an international treaty designed to combat the effects of global warming. In 1997, an addition to the UNFCCC was agreed upon called the Kyoto Protocol. The Kyoto Protocol legally bound the industrial countries that signed to reduce their GHG emissions. The nations were tasked with reducing their individual GHG emissions in the most efficient way they found. The Kyoto Protocol also called for cap and trade system for carbon emissions in order to provide for additional opportunities to achieve reduction goals. While United States has not ratified the Kyoto Protocol, it has increased awareness of the issue of global warming and GHG emissions (UNFCCC, n.d.).

2.8.2 The American Clean Energy and Security Act

The issue of governmental regulation of GHG emissions has seen an increased amount of attention in the United States recently. The main reason is the American Clean Energy and Security Act (American Clean Energy and Security Act of 2009, 2009). One goal of this bill, which is also known as the Waxman-Markey bill, was to reduce carbon emissions in the United States. The major driving forces to accomplish that goal were to create a cap and trade system and require electric utilities to provide a certain percentage of their electricity by renewable sources. The bill was passed by the House of Representatives in June of 2009 but was never voted on by the Senate. The session of Congress in which it was proposed (111^{th}) concluded without further action; which means the bill must be reintroduced to a future session of Congress (H.R. 2454 - 111th Congress: American Clean Energy and Security Act of 2009, 2009).

2.8.3 EPA Reporting Rule

Another driving force for the increased awareness of GHG emissions is the recent GHG initiatives undertaken by the US Environmental Protection Agency (EPA). Following a Supreme Court ruling that GHG emissions are classified as an air pollutant by the Clean Air Act, the EPA released an “endangerment finding” stating that GHG emissions are harmful to “public health and welfare” (Hoffman, 2010). The first action by the EPA was to invoke a GHG emissions reporting rule in order to gather more information on emission quantities. The reporting rule applies to certain entities that emit greater than 25,000 metric tons of CO_2-eq. annually. The sectors involved in reporting include power generation, solid waste landfills, petroleum refineries, and large industrial sources such as chemicals and cement. Water treatment is not yet included in the reporting rule; however, programs will likely continue to grow and include an increasing number of industries (Hoffman, 2010).

2.8.4 Voluntary Reporting and Reductions

While water production is not currently regulated in terms of GHG emissions, there exist voluntary emissions reporting and reduction programs. These include national initiatives such as the Climate Registry along with state-specific initiatives such as the California Climate Action registry. One of the most comprehensive programs is the Chicago Climate Exchange, which not only has registration and reduction initiatives but also a GHG emissions trading market (Huxley, et al., 2009). A growing number of states also have GHG related initiatives. Forty three US states have some sort of GHG inventory program while 36 have a climate action plan (Hoffman, 2010). In addition to inventories and planning, 22 states have GHG emissions targets in place (Hoffman, 2010).

2.9 Water-Energy Nexus

An additional topic receiving increased attention is the water-energy nexus. This idea revolves around the fact that producing water requires energy while at the same time producing energy requires water (Glassman, et al., 2011). The water-energy nexus is often discussed in the context of the future of the United States electrical grid. For example, Mann (2011) makes the argument that when creating tax incentives for renewable energy sources, the water consumption as well as the GHG emissions of that energy source should be taken into account. The rationale is that while the goal is to decrease GHG emissions, utilizing an energy source that requires much greater quantities of water will not help reduce the overall environmental impact. The concept is becoming important enough that governments such as Ontario are beginning to evaluate the relationship between their energy and water usage (Maas, 2010).

The main issue confronting further evaluation of the water-energy nexus is the reliability of the data accounting for how much water is consumed while generating a given amount of electricity (Glassman, et al., 2011). An important vocabulary difference to note is that water consumption is important, not necessarily water withdrawal. Water consumption involves removing water from its source permanently, while water withdrawal removes water then returns that water back to its source. For example, nuclear power withdraws large amounts of water for cooling purposes, but returns the majority of that water to its source while only a small portion is lost due to evaporation. While the data are incomplete, Glassman et al. (2011) presented what they believed to be the most accurate set of water consumption data available (Table 2.11). The two entries for hydroelectric stem from two different sources (the US Geological Survey and the US Department of Energy) that use different definitions for water withdrawn versus water consumed. Both of those options relate to hydroelectric processes that include a reservoir; the third hydroelectric option is for a run-of-the-river process.

Table 2.11 Water consumption data for various electricity production methods [adapted from (Glassman, et al., 2011)].

Electricity Production Method	Water Consumed (gal/MWh)		
	Minimum	Maximum	Average
Coal	305	550	427.5
Coal IGCC	200	200	200
Oil	305	550	427.5
Natural Gas	185	250	217.5
Hydroelectric (Source 1)	0	0	0
Hydroelectric (Source 2)	4500	4500	4500
Hydroelectric (Run of the River)	0	0	0
Nuclear	400	720	560
Wind	0	0	0
Solar Photovoltaic	0	0	0
Geothermal	1400	1400	1400

2.11 Summary

Due to increasing costs and a greater focus on environmental practices, energy use at water utilities has received increased emphasis over the past decade. Energy use investigations have been completed on a national and state-wide scale, with the results providing overall average values. More detailed energy use data are still somewhat lacking, including energy prediction equations for various phases of water production. In addition to energy use, GHG emissions have become a significant topic due to potential EPA regulation and federal legislation. Due to this increased emphasis on GHG emissions, tools assisting organizations in accounting for their GHG emissions will become vital. While GHG accounting tools exist for generic purposes, there is a need for such a tool developed for water utilities in the United States.

CHAPTER THREE

RESEARCH OBJECTIVES

The main objective of this thesis project was to develop an accounting tool that will allow for water utilities to calculate their GHG emissions. Using this tool, utilities will be able to assess their carbon inventory and footprint and their impact on climate change. It will facilitate the creation of an emissions baseline and assist in meeting any emissions reduction goals. The tool will also become beneficial should a mandated GHG emissions reporting rule or reduction program apply to water utilities. To accomplish the main objective, this research project focused on the following four sub-objectives:

1. ***The first sub-objective was to create an Excel-based program to serve as the shell of the GHG accounting tool.*** Prior to developing the program, a comprehensive literature review was conducted to compile all available data, equations, and other useful information related to the GHG emissions of water utilities. For the program itself, Excel was chosen because it is a common, widely used tool that can be used by people with a wide range of computer experience. The Excel program contains all the necessary data entry locations along with the formulas and data needed to determine the GHG emissions.
2. ***The second sub-objective was to develop energy prediction equations for different portions of the water production process.*** Energy use has been shown to be the major contributor to GHG emissions for water production, so it was important to provide a way to determine that information if not know to the water utility. Energy use predictions were developed for three portions of

water production: (i) raw water collection, (ii) treatment, and (iii) finished water distribution. To construct these equations, data on energy use and system characteristics were obtained using surveys conducted by others as well as the author of this thesis.

3. ***The third sub-objective was to include the water-energy nexus in the GHG accounting tool.*** The amount of electricity used at a given utility was used to determine the amount of water consumed in producing that electricity. That water consumption was then utilized to determine a net water production value for the utility.
4. ***The fourth sub-objective was to test the program using real data at various water utilities.*** This process served two functions. The first was to gather an idea of the scale of GHG emissions associated with a variety of water utilities. The second function was to obtain feedback about the program from its intended users.

CHAPTER FOUR

DEVELOPMENT OF GHG EMISSIONS ACCOUNTING TOOL

This chapter will discuss the development of the Excel-based tool created to calculate the GHG emissions of a water utility. Each tab of the program is broken up into a different section of this chapter. The user will first choose the applicable electrical grid for their utility then enter data concerning the raw water collection, treatment process, finished water distribution, and buildings/fleet/other portions of the utility. The various options used to present the GHG emission totals will also be discussed. References to the emission factors used to calculate the GHG emissions will be made throughout the chapter. A copy of the software can be found on the Clemson University Environmental Engineering & Earth Sciences department website (http://www.clemson.edu/ces/departments/eees/).

4.1 Electrical Grid

As seen in the LCA studies described in sections 2.2 and 2.3, the electrical grid being used by a water utility has a large impact on its GHG emissions. Therefore, it is imperative to determine the make-up of that electrical grid as accurately as possible. The goal of the program is to be accurate while still providing the utility with flexibility. To accomplish that goal, a water utility will have four options when selecting their electrical grid. They are presented here in decreasing order of accuracy (option 1 being the most accurate and option 4 being the least accurate).

The first option is for the utility is to manually enter the applicable electricity emission factors. These factors can at times be obtained directly from the electricity provider and will therefore be the most accurate source of emission factors. The utility will enter the emission factor for CO_2, CH_4, and N_2O. If these factors are not available, the utility will move on to options 2-4.

The second option involves using the zip code of the water utility to locate the corresponding EPA subregion and the electricity emissions factors that match that subregion. The EPA has broken the country into electrical grid subregions that provide a more localized and accurate view of the electrical grid being utilized by an organization in that area (Figure 4.1). To determine in which subregion a water utility resides, a zip code search function is included in the program. The user will simply enter the zip code of their water utility; the program will then match their zip code with the corresponding EPA subregion and automatically fill in the electricity emission factors. The electricity emission factors that correspond to each EPA subregion are provided in Table B-1. Situations will arise where a given zip code lies on the border between subregions, with this most often occurring because multiple electricity providers operate in the same zip code. The program will alert the user when this occurs and direct them to an EPA website for assistance in locating their proper subregion.

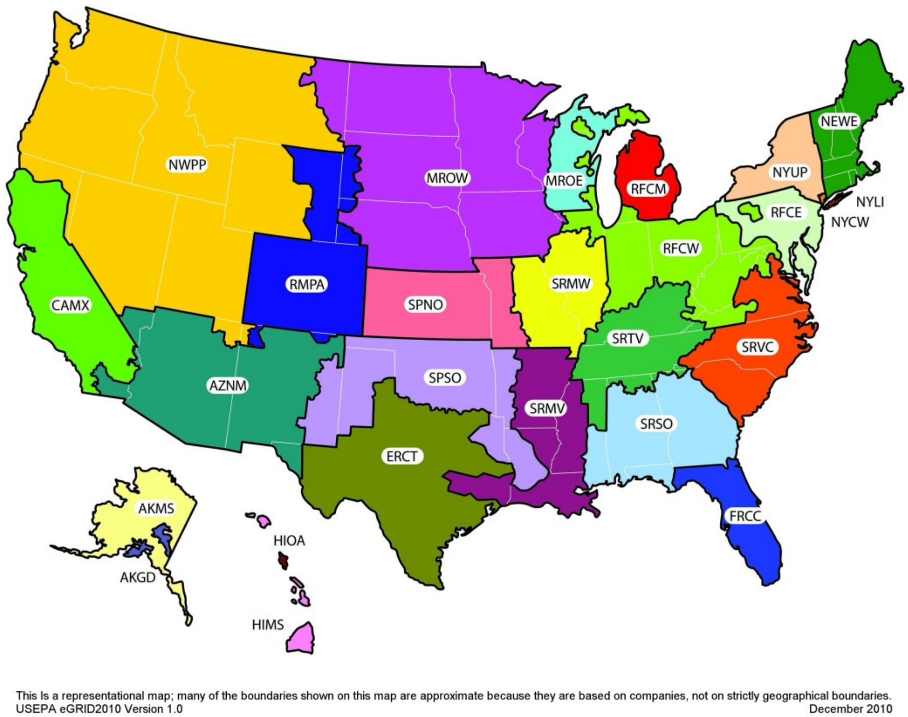

Figure 4.1 National map of the EPA electrical grid subregions (USEPA, 2010).

The third option is to utilize the United States national average emission factors. Those factors are located in Table B-2.

The fourth and last option for electrical grid selection is for the user to manually enter in the make-up of their electrical grid. This would involve selecting percentages of the following technologies to compose their electrical grid: coal, natural gas, oil, nuclear, hydroelectric, biomass, wind, and solar. This option would most likely be used by utilities that have some sort of renewable electricity generation on site, such as solar panels. Under this circumstance, the local electrical grid would not be a good indication of the GHG emissions from electricity production. Manually entering the electrical grid utilizes the emission rates seen in Figure 2.3, which are shown in table form in Table B-3.

This option has one significant difference in that the GHG emissions are only measured as CO_2-eq. and are not broken down into the individual GHGs (CO_2, CH_4, and N_2O) as is done in the other three options.

4.2 Raw Water Collection

The first step in determining the GHG emissions from raw water collection is entering the annual fuel consumption of this section of the water utility. The amounts of fuel used will then be multiplied by the emission factor for that specific fuel to determine the GHG emissions. The specific fuels that can be included are natural gas, propane, liquid propane, diesel, various fuel oils, kerosene, coal, coke, and wood (which would also serve as biomass consumption). The emission factors for each fuel are presented in Table B-4. While these fuels will most likely be utilized in other portions of the water utility, some pumping operations are run on fuel combustion and not electricity, even if only for a short period of time. For example, diesel back-up generators and natural gas powered pumps are in use in the field.

The next category of data to be entered for raw water collection is electricity usage. There are two options for the user to enter their electricity usage. The first, and most accurate, option, if available and measured, is for the water utility to simply enter the annual kWh of electricity used in the raw water collection phase. The second option utilizes an energy prediction equation that calculates an annual electricity usage for the raw water collection phase of the utility. The energy prediction equation uses data on the total average flow rate, purchased water flow rate, and raw water collection horsepower and will be discussed in further detail in Chapter 5. Once the annual electricity usage is known, from direct entry or the energy prediction equation, the electricity emission factors from the electrical grid selected previously will be used to calculate the GHG emissions.

4.3 Treatment Processes

The next portion of the water utility to be evaluated is the water treatment processes. Similar to the raw water collection phase, the first data to be entered are the annual fuel usage for the treatment phase. The specific fuels that can be chosen are the same as those listed previously and the emission factors for each fuel can be seen in Table B-4.

The next section of data entered into the program involves direct emission sources, or Scope 1 sources, that are specific to the potable water production process. First, if ozone is used for oxidation or disinfection, the annual volume generated is entered into the program. This would apply to only those utilities that use air as the supply to the ozone generation systems and not pure oxygen. The reason for this is that the nitrogen in the air reacts in the ozone generation process to produce N_2O (Huxley, et al., 2009). Next, data are collected on the amount of granular activated carbon (GAC) regenerated annually on-site, meaning within the organizational boundary of the water utility. This accounts for the carbon that is oxidized to CO_2 and emitted to the atmosphere during the regeneration process. This program assumes that 7.5% of the carbon that is regenerated is released as CO_2 (Huxley, et al., 2009). This calculation does not include the fuel used to operate the regeneration process, which should be taken into account under the annual fuel usage section of the treatment phase. The third category of data entry in this section involves GHG emissions from water reservoirs. The water utility will enter the surface area of their reservoirs under the corresponding climate choices of boreal, temperate, subtropical, and tropical. The values will then be used with emission factors to determine the GHG emissions from these sources. The last direct emissions source specific to the potable water production process involves GHG emissions from sludge disposed at a landfill. The user will enter the annual amount (tons) of total organic carbon (TOC) removed by the treatment process that is sent to a landfill. Emission factors are then used to determine the CO_2 and CH_4 emissions. The emission factors utilized for this entire section of direct emission sources are presented in Table B-5.

After the direct emission sources, electricity usage for the treatment phase will be entered into the program. As with the raw water collection phase, there are two options for entering the electricity usage of this phase of water production. First, the known annual electricity usage in kWh from the treatment phase will be entered into the program, which is the most accurate option. If the electricity usage for treatment is not known, literature values will be utilized because an accurate energy prediction equation could not be determined. The process of attempting to develop the treatment energy prediction equation will be discussed in Chapter 5. The second option will consist of the user entering the total average flow rate (in MGD) into the program followed by selecting the treatment steps used in the specific treatment process. The literature data used for predicting the treatment energy are adapted from Figure 2.2. The treatment steps available for selection, as well as their corresponding electricity usage (in kWh/1000 gallons), can be seen in Table 4.1. The utility also has the option of entering a different value for the electricity requirement if it has more accurate data than what is offered in the program. A copy of Figure 2.2 is included in the program so the user can see the range of possible electricity usages for each treatment step; this also gives the users a frame a reference if they desire to change the electricity use factors.

The last section of data collected for the treatment phase concerns chemical usage, which represents Scope 3 emissions. The annual amount (in pounds) of each chemical used in the treatment process will be entered into the program and the GHG emissions are then calculated using emission factors. The chemicals included in the program are alum, ferric chloride, ferrous chloride, chlorine, sodium hypochlorite, lime, polymers, carbon dioxide, oxygen, sodium hydroxide, and ammonia. The specific GHG emission factors for each of these chemicals are shown in Table B-6.

Table 4.1 Treatment steps available for selection in the energy prediction option and their corresponding electricity use factors [adapted from (Veerapaneni, et al., 2011)].

Treatment Step	Energy Use kWh/1000 gal
Static Mixer	0.00475
Rapid Mixer	0.0345
Flocculator (Vert.)	0.0012
Flocculator (Hor.)	0.0027
Conv. Sedimentation	0.0015055
Plate Settlers	0.00168
Superpulsator	0.0385
Ballasted Flocculator	0.0635
Densadeg	0.11
DAF (high-rate)	0.11
Gravity Filtration	0.0315
Pressure Filtration	0.08
MF/UF-Encased	0.25
MF/UF-Submerged	0.265
UV-LPHO	0.0105
UV-MP	0.0555
UV/AOP	0.385
Ozonation	0.060
Hypochlorite (on-site)	0.066
Decarbonators	0.155
Brackish Water RO	3.1
Wastewater RO	2.55
Seawater RO	8.25
Thermal Desalination	21

4.4 Finished Water Distribution

The next phase of the water utility to be evaluated is finished water distribution. Once again, data pertaining to the annual fuel consumption are entered to evaluate the

Scope 1 emissions. The specific fuel options are identical to the other sections and the emission factors for each fuel can be seen in Table B-4.

Next, data on the electricity usage of the water utility for finished water distribution are entered into the program using two options. The first option involves entering the known annual electricity usage (in kWh) into the program; this will again provide the most accurate results. If the electricity usage of the finished water distribution phase is unknown, an energy prediction equation is utilized. The energy prediction equation uses the total average flow rate (in MGD) and total distribution pumping horsepower to determine the electricity usage and will be discussed in further detail in Chapter 5. Once the electricity usage in known, the emission factors from the electrical grid selected previously are used to determine the GHG emissions from electricity production.

4.5 Buildings/Fleet/Other

The last section of the water utility to be evaluated involves sources such as administrative buildings and utility-owned vehicles. First, the annual fuel usage is entered. The specific fuels that can be chosen are identical to those listed in previous sections and their corresponding emission factors are presented in Table B-4. After fuel usage, the annual electricity usage (in kWh) is entered. The emission factors from the electrical grid selected previously are then used to calculate the GHG emissions. This section will take into account the fuel and electricity usage that does not fit into the previous three phases but is still consumed by the water utility. For example, natural gas used for building heating would be included in this section.

After the fuel and electricity usage has been collected, the GHG emissions from mobile combustion sources must be determined. This will include any vehicle that is owned directly by the water utility, but does not include employee-owned vehicles. Fuel used in generators that are considered mobile due to their relatively small size should be entered in the annual fuel usage section described earlier. To determine the CO_2 emissions, only the volume of fuel used each year is required. The user will therefore enter the annual amount of fuel used with the specific fuel options being gasoline, diesel, E85, ethanol, and biodiesel. The CO_2 emission factors for each fuel listed can be seen in Table B-7. The emissions of CH_4 and N_2O depend on more than simply the volume of fuel used. The EPA emission factors rely on the mileage, fuel type, vehicle type, and vehicle model year. The reason for the vehicle type and model year requirement is that CH_4 and N_2O emissions vary based on the type of emissions/catalytic control in place in the vehicle. These control systems vary by vehicle type and model year as newer cars are often responsible for fewer emissions due to improved catalytic control. The user will enter the annual mileage under the cell that matches the corresponding vehicle type, fuel type, and model year. The vehicle types available are passenger cars, light-duty trucks, and heavy-duty trucks. The specific CH_4 and N_2O emission factors for each category are located in Tables B-8 through B-10.

4.6 Emission Totals

Once all the necessary data are entered, this section will provide the various annual GHG emission totals to the user. The GHG emission totals are presented to the user in a number of ways. First, the emissions are broken down into the four water utility phases: raw water collection, treatment process, finished water distribution, and buildings/fleet/ other. Within each of these four phases, the GHG emissions are separated into the Scopes 1, 2, or 3. While Scope 3 emissions can include a wide range of emission sources, the only source chosen for this tool was emissions from chemical production; meaning that the only phase of the water utility that contains Scope 3 emissions is the treatment process. This was the only Scope 3 emissions source chosen because, as seen in section 2.2, chemical production often represents the second greatest source of environmental impacts after electricity/energy use. After separation into each Scope, the emissions are broken down into the individual GHGs (CO_2, CH_4, and N_2O). The emissions are also combined into units of kg CO_2-eq./year. There are some selections within the program that will only show the amount CO_2-eq. and not the individual GHGs (CO_2, CH_4, and N_2O); these include manual entry of the electrical grid composition and the emissions from chemical production. The reason for this is that the emission factors for these calculations could only be found with units of CO2-eq. The GHG emissions from within each phase are then combined into a carbon inventory or a carbon footprint. A carbon inventory consists of Scope 1 and 2 emissions while a carbon footprint sums Scope 1, 2, and 3 emissions.

The GHG emissions of the entire water utility are then summed and broken down in the same manner as each individual phase. To provide a more visual representation of the source of GHG emissions within the water utility, the program creates four graphs. All graphs are based on the GHG emission totals in CO_2-eq./year. The first graph is a pie chart that displays the contributions of each phase of the water utility. The graph will illustrate whether raw water collection, the treatment process, finished water distribution, or buildings/fleet/other are responsible for the greatest amount of GHG emissions. An example of this graph can be seen in Figure 4.2. The second graph utilizes the same data as the previous graph but in a bar chart form while also plotting the total GHG emissions. An example of the second graph is presented in Figure 4.3. Both of these first graphs omit the Scope 3 emissions because these emissions only fall under the treatment phase and may tend to skew the graphs. The third and fourth graphs involve presenting the total GHG emissions of the water utility by Scope. The third graph is a pie chart showing the percentages that each Scope contributes to the total GHG emissions. The fourth graph presents the total GHG emissions of each Scope in bar chart form while including the total GHG emissions as a reference. Examples of the third and fourth chart are shown in Figures 4.4 and 4.5, respectively.

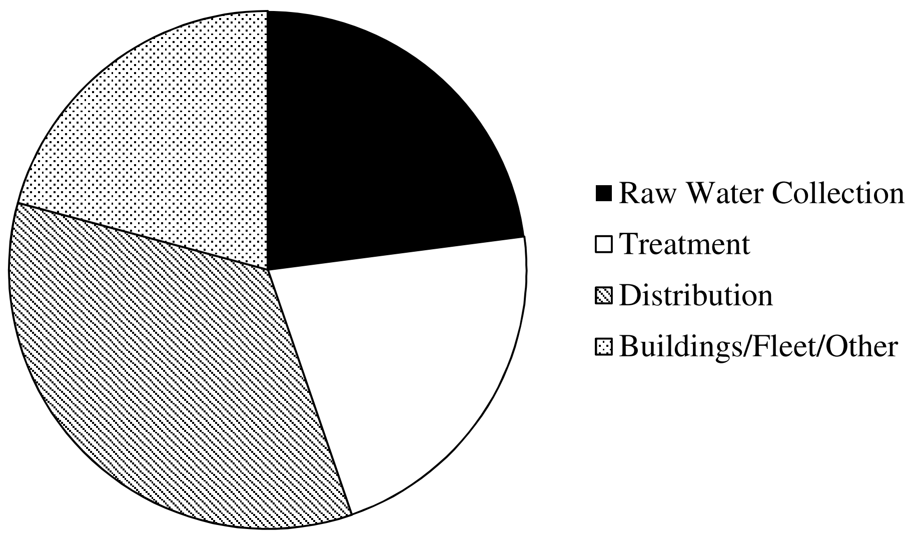

Figure 4.2 Example pie chart from GHG accounting tool depicting relative amount of GHG emissions from different phases of a water utility.

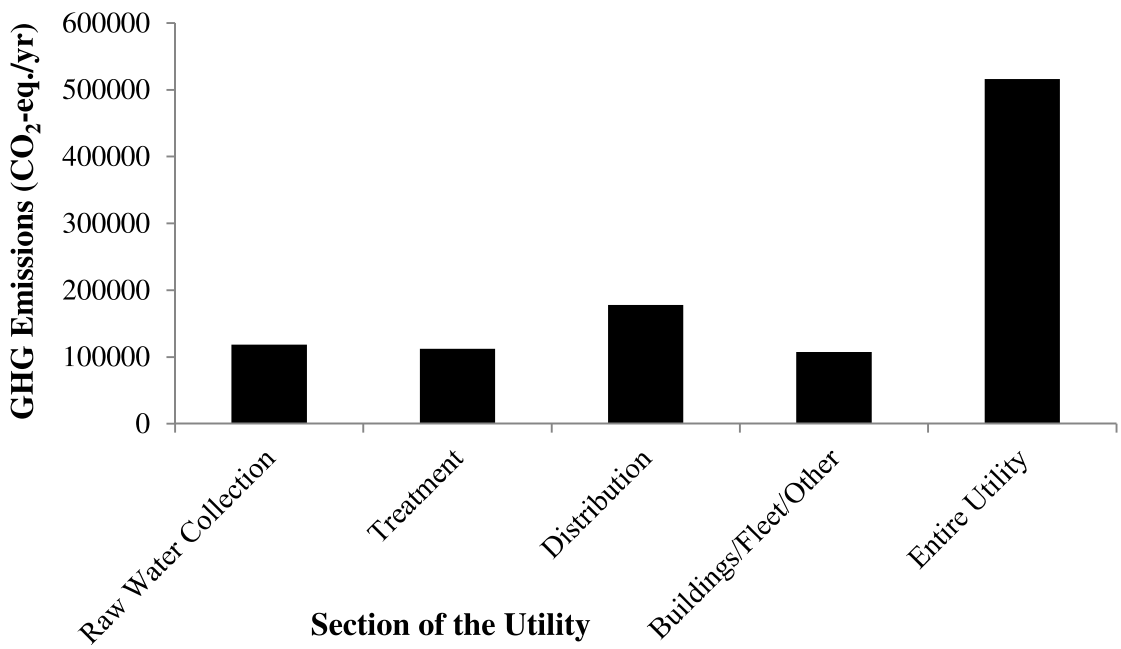

Figure 4.3 Example bar chart from GHG accounting tool depicting amount of GHG emissions from different phases of a water utility.

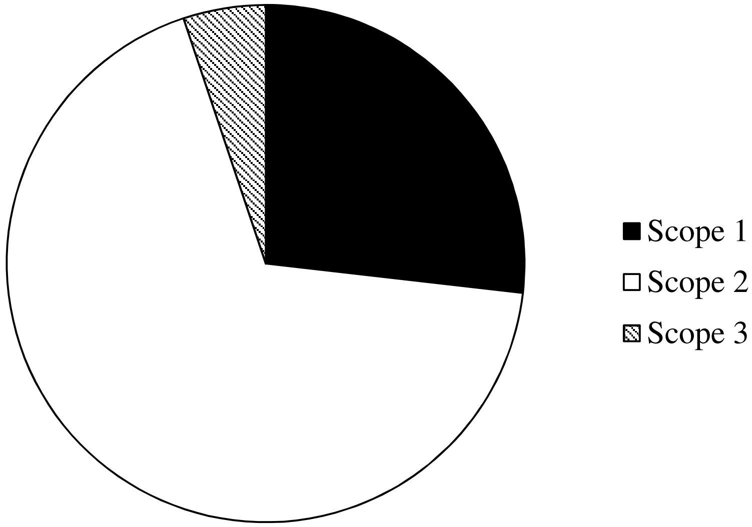

Figure 4.4 Example pie chart from GHG accounting tool depicting relative amount of GHG emissions from different emission sources (Scopes) within a water utility.

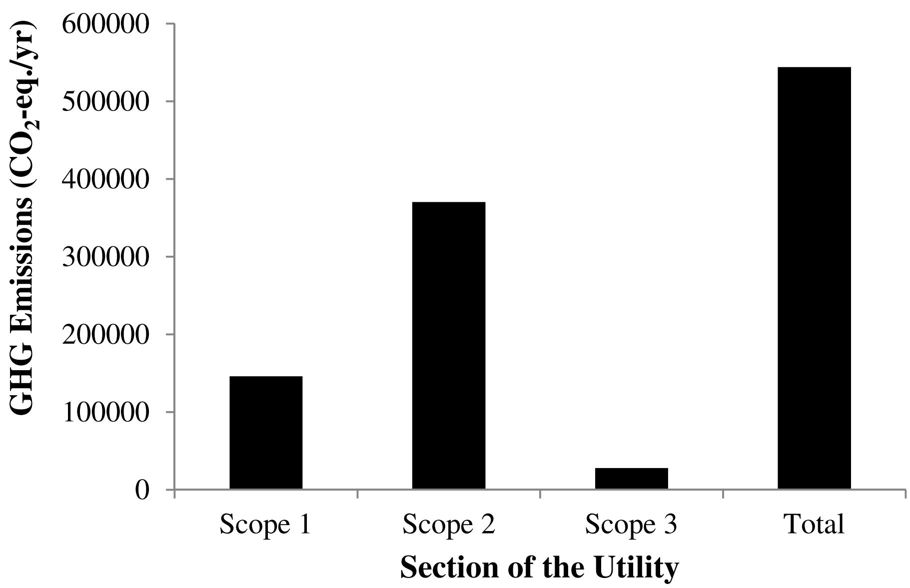

Figure 4.5 Example bar chart from GHG accounting tool depicting amount of GHG emissions from different emission sources (Scopes) within a water utility.

4.7 Net Water Production

This section of the program does not deal with GHG emissions, but rather the concept of the water-energy nexus. The first step in evaluating the impact of the water-energy nexus is to calculate the amount of water consumed in generating the electricity used to power the water utility. That amount of water is then subtracted from the water produced at the utility to give the net water production.

The water utility will first enter their average total water production (in MGD) for a given year. Next, the zip code of the utility will be entered in order to determine the make-up of the electrical grid. The zip code will be matched with the corresponding EPA subregion, which are identical to the subregions used to determine GHG emission factors and are located in Figure 4.1. The make-up of the different subregion electrical grids can be seen in Table B-11. The total amount of electricity used by the water utility will then be separated into the amounts generated by the various electricity production methods in the corresponding subregion. The amount of water consumed to produce the required amount of electricity is then calculated using the water consumption factors in Table 4.2.

The water consumption factors used in the program include some additions and deletions from the raw report data shown in Table 2.11. First, two different values were given for coal; one for a traditional thermoelectric process and one for the more recent integrated gasification combined cycle (IGCC) process. The value for the traditional thermoelectric process was selected for the program because it is more common and will be a better estimate for a wider range of electrical grids. The data compiled by Glassman et al. (2011) do not include data for electricity generation from biomass. The water consumption value for biomass was assumed to be identical to that of coal and oil. This was selected because biomass is often used in a co-firing process where a small amount of biomass is added to a thermoelectric coal process. The last assumption that was required involved the water consumed in a hydroelectric process. Three values were given by Glassman et al. (2011), two different values for hydroelectric with a reservoir and one for a run-of-the-river process. The value of 4500 gal/MWh was chosen, which correlates to the more common reservoir hydroelectric process. A reservoir hydroelectric process increases evaporation rates due to the increased surface area of the water, thus providing the rationale for selecting the value of 4500 gal/MWh over zero gal/MWh.

Table 4.2 Water consumption factors for various electricity production methods used to determine net water production [adapted from (Glassman, et al., 2011)].

Electricity Production Method	Water Consumed (gal/MWh)
Coal	427.5
Oil	427.5
Natural Gas	217.5
Biomass	427.5
Hydroelectric	4500
Nuclear	560
Wind	0
Solar PV	0
Geothermal	1400

CHAPTER FIVE

DEVELOPMENT OF ENERGY PREDICTION EQUATIONS

This chapter will discuss the steps taken in order to develop energy use prediction equations for the three phases of water production. The data collection via surveys will first be discussed followed by an explanation of the statistical tests used and the general process taken to develop the energy use prediction equations. Lastly, the specific development of regression models for the raw water collection, treatment, and finished water distribution phases will be discussed.

5.1 Surveys

To develop energy prediction equations, data on the energy use of water utilities were required. The best way to obtain these data was through surveys. First, the raw survey data from the AwwaRF report (Carlson & Walburger, 2007) were obtained. To augment this data set, a new survey (i.e., Clemson survey) was designed and conducted for this thesis research. The questions asked in the Clemson survey can be found in Appendix C. The AwwaRF report used mailed surveys and received a 13% response rate. The Clemson survey used an online survey tool (surveygizmo.com) and emailed the links to the perspective water utilities. The Clemson survey sent survey links to 378 water utilities with 37 offering qualified responses, providing a 10% response rate. The low response rate is believed to be for multiple reasons. First, most water utility employees are busy people and simply do not wish to take the time to fill out a survey. In addition to the lack of motivation, it became apparent during the survey process that a number of water utilities do not have the desired energy use information. Some simply did not care or know because often, the electrical bills are handled at the town offices and the water utility itself does not see the bill; this is especially true for smaller utilities, whereas others shared an electric meter making it difficult to separate the charges.

In order to sort through the survey responses, two initial filters were used. If the water utility did not provide (i) flow rate information and (ii) electricity use information, it was deleted from further analysis. This action resulted in 155 possibly useful responses from the AwwaRF survey and 37 possibly useful responses from the Clemson survey. The survey responses illustrate a wide distribution geographically (see Figure 5.1) as well as by utility size (see Figure 5.2). The useful survey responses yielded an average energy use of 3.1 kWh/1000 gal.

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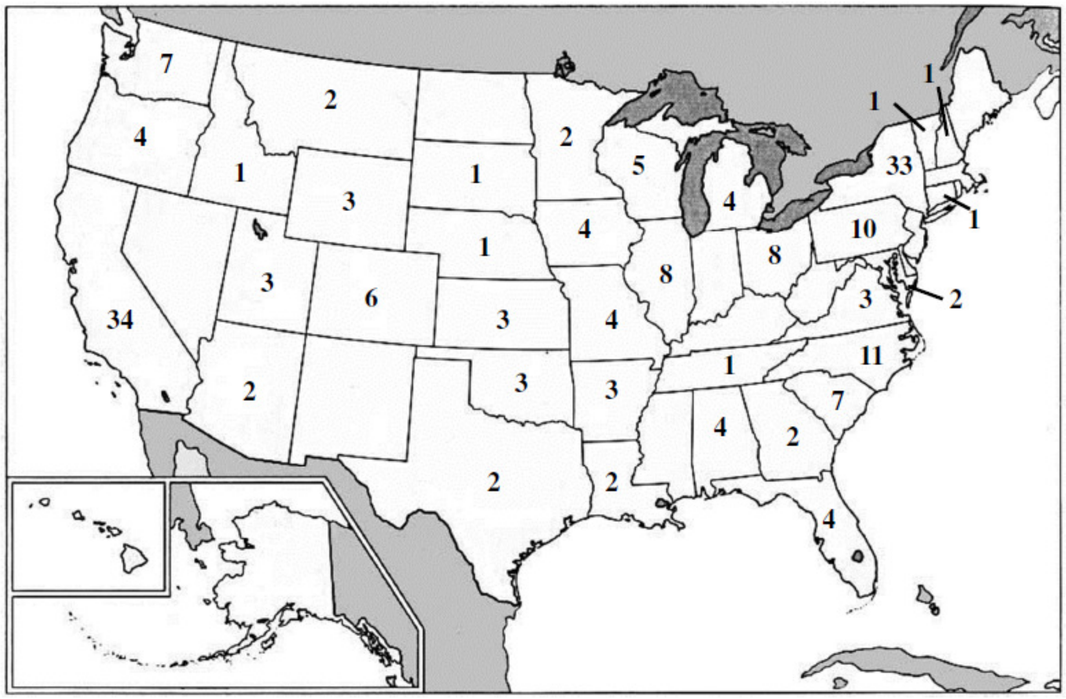

Figure 5.1 Geographical distribution of the combined survey responses.

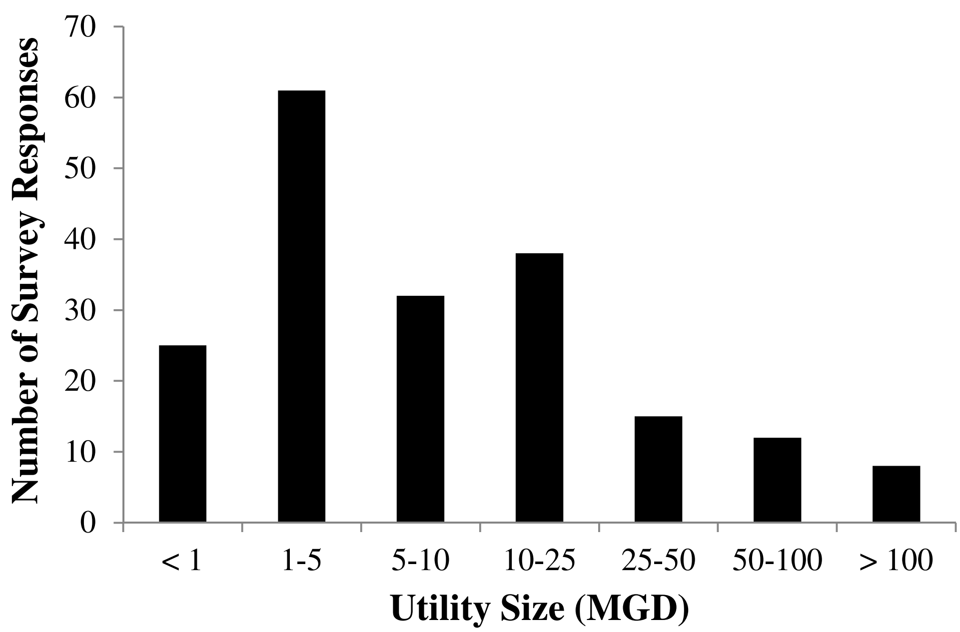

Figure 5.2 Distribution based on utility size of the combined survey responses.

5.2 General Steps for Equation Development

Development of the energy prediction equations for different phases of water treatment requires a number of various statistical tests. To analyze the independent variables selected, a significance level (or p value) is used to assess whether an independent variable was statistically significant. The goal is to use independent variables with a p value less than 0.05. The p value of 0.05 means that there was a five percent chance that the influence of the independent variable on the regression equation occurred by coincidence (Ott & Longnecker, 2010).

When developing a regression equation with multiple independent variables, an analysis for multi-collinearity must be performed. Multi-collinearity occurs when minor changes in the independent variables lead to significant changes in the regression coefficients due to the independent variables being related to each other. Testing for multi-collinearity is accomplished using variance inflation factors. A variance inflation factor (VIF) of 1 indicates no multi-collinearity, while a value of 10 indicates potential multi-collinearity and should be investigated further (Ott & Longnecker, 2010).

Another aspect of the regression equations that must be evaluated is identifying observations that have a strong impact on the regression equations. There are two parameters used to gauge this effect. The difference in fit (DFFITS) locates observations that have a large influence on the predicted value of the regression equation. The difference in beta (DFBETAS) locates observations that have a strong effect on the individual regression parameters for each independent variable (Belsley, Kuh, & Welsch, 1980).

In addition to the tests described above, two more are utilized when evaluating the regression equations. First the studentized residual, or RStudent, is used to locate dependent variables that deviate far from the predicted value (Ott & Longnecker, 2010). To test the goodness of fit for the model, a chi square test is utilized. This test produces a p value, where a value between 0.05 and 0.15 represents a moderately good fit and is considered acceptable (Ott & Longnecker, 2010). P values above 0.15 represent increasingly better fits for the model (Ott & Longnecker, 2010).

To develop the energy prediction equations, the statistics program Statistical Analysis Systems (SAS) was utilized because it allows for the simple production of multi-linear regression models. SAS also has the ability to use the lasso selection method for identifying significant independent variables. The lasso selection method was recommended by Flom and Cassell (2009) as an alternative to the forward selection method used by Carlson and Walburger (2007). Lasso selects the most appropriate combination of independent variables for a linear regression model by minimizing the sum of squared errors from the given data set (Tibshirani, 1996).

The goal was to form energy prediction equations for three different phases of water production: (i) raw water collection, (ii) treatment, and (iii) finished water distribution. The first step was to identify possible independent variables, which were reported in both surveys, for each of the three phases of water production. SAS was then used to run the lasso selection method to identify the significant independent variables followed by the compilation of a regression model using those independent variables. The output regression model was then analyzed using the statistical tests discussed earlier in this section. After any outlier or erroneous data points were identified and deleted, the process of lasso selection, regression model formation, and model analysis was repeated until an acceptable regression model was obtained.

Two additional items were critical to developing the energy prediction equations. The survey data obtained have a large range and variance, so a transformation of the data was required. Both a log, specifically $\log_{10}$, and a square root (SQRT) transformation were investigated. The transformations were performed on both the dependent and independent variables, so instead of the independent variable being energy use, it is now the $\log_{10}$ of energy use. The other critical item was choosing whether to use total energy use or simply electricity use. The decision was made to use only electricity use and not attempt to combine natural gas, diesel, etc. with electricity for two reasons. First, the data obtained from the AwwaRF report (Carlson & Walburger, 2007) did include the amount of various fuels used; however, it did not indicate what phase of water treatment those fuels were used to power. Attempts were made to determine this information, but to no avail. Additionally, the Clemson survey responders were asked in what portion of their utility their fuel usage took place. The majority of those responding indicated fuel usage, mostly natural gas, was utilized for building heating. The assumption of only including electricity was deemed valid because building heating was not a process being model by the energy prediction equations.

5.3 Raw Water Collection

The first model to be developed was for the raw water collection phase of the water utility. The first step in the formation of this model is to select the potential independent variables for future analysis, with the following variables selected: average groundwater flow, average surface water flow, average purchased water flow, total average flow, average well depth, and source water pumping horsepower.

Next, the survey data were narrowed to the water utilities that provided electricity use for the raw water collection phase. If independent variables, such as pumping horsepower, were left blank by the utility that plant would simply be ignored by SAS when forming a regression model. The data used to form the raw water collection model are presented in Table D-1.

Two small adjustments to the data were then required to be able to model a regression equation. First, a value of zero needed to be a valid entry for multiple of the potential independent variables, which would cause an error when performing the $\log_{10}$ transformation. To solve this issue, a value of one was added to each of these independent variables. However, solving the first issue may have created another one in that adding a value of one to flow rate values that can often been in the range of 1-10 can cause problems in the modeling. This problem was solved by using the thousand gallons per day (kGD) flow rate values instead of the MGD values.

Before running SAS, five water utilities were deleted. Four (CA023, OK003, PA006, and WY001) were deleted because they indicated zero pumping hp but listed a non-negligible electricity use. The only major electricity consumption source in the raw water collection phase is pumping, so these data points did not make sense and were deleted. The most likely cause of the erroneous listing is that the utilities did not know their pumping hp and left that entry blank on their survey, which was then turned into a zero by the time the report data was published. An additional point (CA045) was deleted because it listed an energy use of 8 kWh/yr while having a pumping hp value of 270. These values are not logical; therefore, the data point was deleted.

The first regression model to be formed was the $\log_{10}$ model. The lasso selection method was utilized and the following independent variables were selected:

1. Log_{10}(Total Average Flow)
2. Log_{10}(Source Water Pumping HP)
3. Log_{10}(Total Average Flow)* Log_{10}(Source Water Pumping HP)

SAS was then used to form a regression model using these three independent variables. Three data points were found to be outliers and deleted. CA011 and CA046 fell well outside the general range and had residual values that were too large (RStudent values greater than $|4|$). PA004 had an unusually large influence on the model while having a relatively high value for electricity use for the given hp value.

The lasso selection model was run again, yielding an identical independent variable selection. The model formed using these variables illustrate problems with multi-collinearity, as seen with VIFs greater than 10. To correct this, centering was performed where each water utility has the mean of each independent variable subtracted from the corresponding variable during model formation. This process corrected the multi-collinearity problem and also illustrated that the independent variable Log_{10}(Total

Average Flow)* Log_{10}(Source Water Pumping HP) was no longer significant. A regression model was then formed using the remaining two independent variables. When analyzing this new model, some data points with large residuals appear to be those utilities with purchased water flows. In these cases the water is provided at pressure already and the energy used to pump the water is included in the cost of buying the water and not the energy use of the utility. The purchased water flow was not indicated by the lasso selection, but was used as an independent variable by Carlson and Walburger (2007). In order to add purchased water flow rate as an independent variable, the raw water collection model was split into two; one for utilities with purchased water flows and one for those without. Once split into two separate models, the purchased water flow rate now became a significant variable. Upon analyzing the two models, a few more data points were located that merit deletion. VA005 is on the extreme upper end of the range and the raw data shows a likely estimation of electricity use rather than actual data. Two utilities show a low electricity value compared to its other characteristics, MD001 and CA020. All three points were deleted and the models were run again. The results showed a good fit for both models. The residuals are evenly distributed and while there are points with high levels of influence on the model, there is no single point with an overwhelming amount of influence.

The final $\log_{10}$ model for raw water collection without purchased water flow is:

$$Log_{10}(Electricity\ [kWh/yr]) = 3.04430 + 0.42367 * Log_{10}(Total\ Average\ Flow\ [kGD]) + 0.57216 * Log_{10}(Raw\ Water\ Collection\ Pumping\ HP + 1) \tag{2}$$

The model has an R^2 value of 0.79 and a graph comparing the actual electricity use and the predicted electricity use can be seen in Figure 5.3.

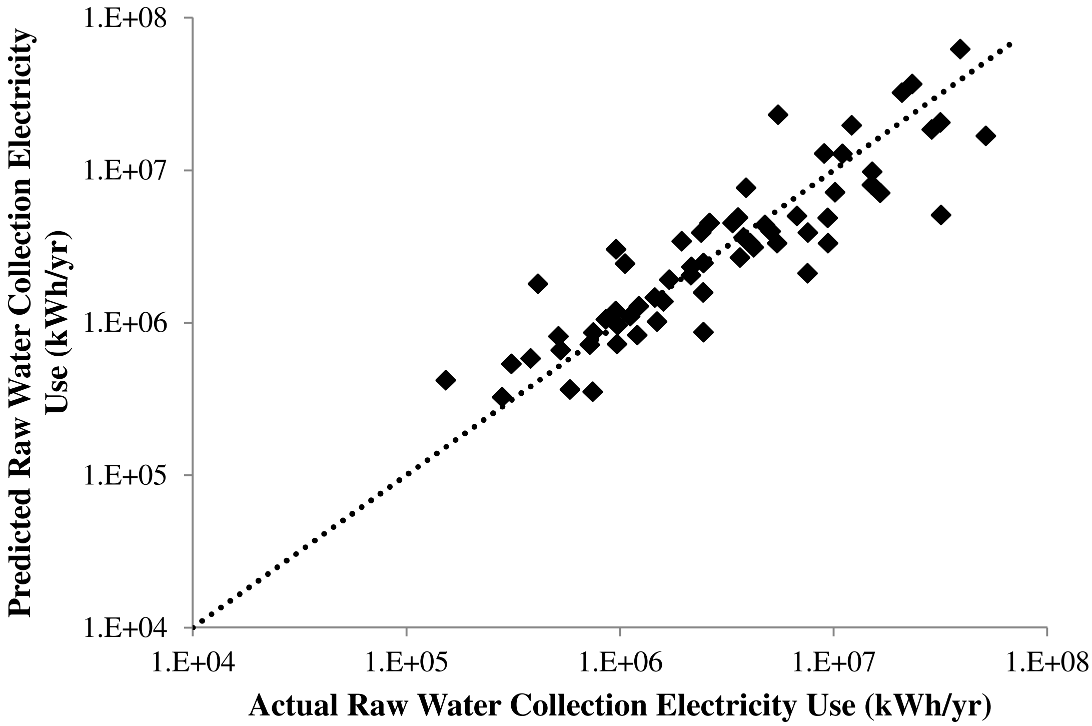

Figure 5.3 Illustration of the actual raw water collection electricity use from various water utilities without purchased water flow versus the value of the electricity use predicted by the regression model (n=64).

The final $\log_{10}$ model for raw water collection with purchased water flow is:

$$Log_{10}\ (Electricity\ [kWh/yr]) =$$

$$2.91331 + 0.80696 * Log_{10}(Total\ Average\ Flow\ [kGD]) +$$

$$0.51377 * Log_{10}(Raw\ Water\ Collection\ Pumping\ HP + 1) - \quad (3)$$

$$0.35124 * Log_{10}(Average\ Purchased\ Water\ Flow\ [kGD] + 1)$$

The model has an R^2 value of 0.87 and a graph comparing the actual electricity use and the predicted electricity use is illustrated in Figure 5.4.

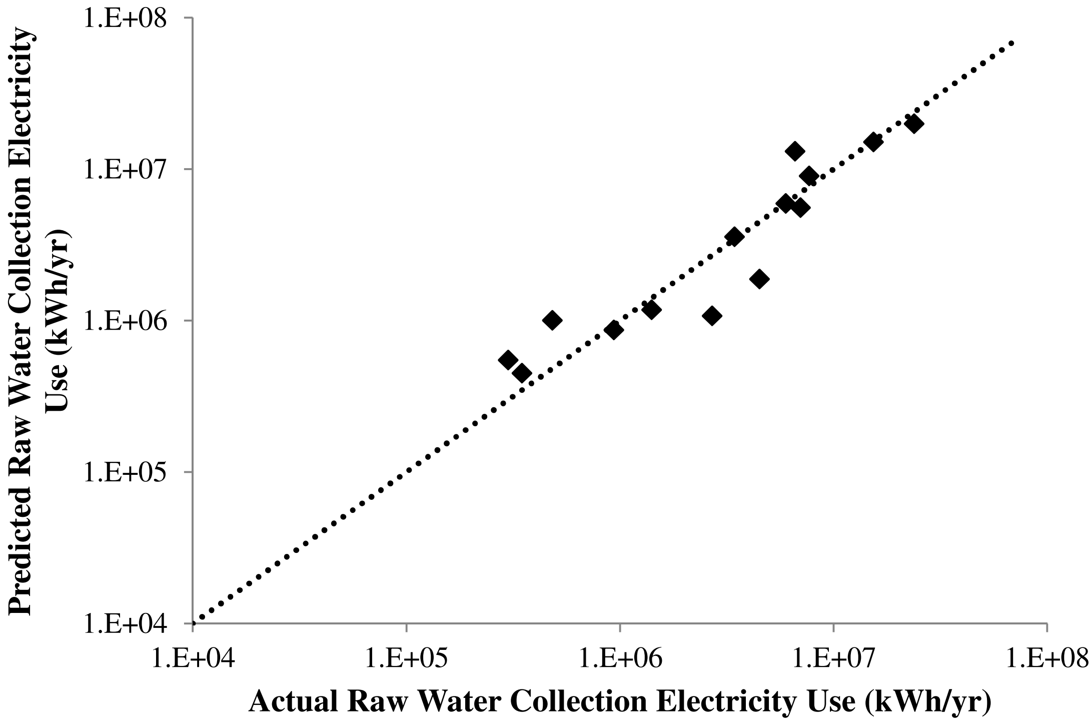

Figure 5.4 Illustration of the actual raw water collection electricity use from various water utilities with purchased water flow versus the value of the electricity use predicted by the regression model (n=14).

A second raw water collection regression model was investigated using a square root transformation of the data. In addition to the original five deleted data points, three additional points were deleted before running SAS due to the reliability issues illustrated in forming the $\log_{10}$ regression model. These points were CA046, PA004, and VA005. The lasso selection method was utilized and the following independent variables were selected:

1. SQRT(Total Average Flow)
2. SQRT(Source Water Pumping HP)
3. SQRT(Total Average Flow)* Log_{10}(Source Water Pumping HP)

SAS was then used to form a regression model using these three independent variables. Two data points were found to have large residuals and lie well outside the range of the rest of the data. These points, PA007 and PA008, were deleted. The lasso selection method chose identical independent variables and the regression model was run again. Two additional data points, OR003 and CA020 were found to have large residuals and were deleted. An additional point, IL002, had an abnormally large influence on the model because it was the only point in the upper end of the range. The data point was deleted so the model did not rely so heavily on a single point. At this point, the same issues that affected the $\log_{10}$ transformation model appeared. The independent variable SQRT(Total Average Flow)* Log_{10}(Source Water Pumping HP) was removed to prevent multi-collinearity and SQRT(Average Purchased Flow) was added as an independent variable. Once this model began to be analyzed, the pitfall of the SQRT transformation became apparent. The regression model shows one data point with an enormous amount of influence on the model coefficients. When that point is deleted, another single data point shows an abnormally large amount of influence and this trend continues on. These points that have such a large influence are utilities on the higher end of electricity usage. The SQRT transformation does not distribute the data points as evenly as the $\log_{10}$ transformation, thus giving any single large electricity user a large amount of influence on the model coefficients. Due to the uneven distribution of the SQRT transformation and its inability to accurately model the upper range of electricity usage, the $\log_{10}$ transformation models were chosen for the raw water collection phase.

5.4 Treatment Processes

The next model to be developed was for the treatment phase of the water utility. A large number of potential independent variables were selected for analysis. First, a group of flow rate variables were chosen: average groundwater flow, average surface water flow, average purchased water flow, and total average flow. Next, various treatment schemes were utilized as possible independent variables: conventional treatment, direct filtration, slow sand filtration, dissolved air flotation (DAF), membrane filtration, nanofiltration, and RO. Lastly, individual treatment steps were selected that increase the energy use of the treatment process: pressure filtration, aeration, ozone, softening, and UV disinfection.

The survey data were then narrowed to the water utilities that provided electricity use data for all three phases of water production (raw water collection, treatment, and finished water distribution). This step was meant to ensure that only the treatment phase electricity use was utilized in the model formation. If a utility reported electricity data for treatment and not raw water collection, there was a possibility that the electricity required by raw water collection would be included in the value reported under treatment. As the plants that provided data to the AwwaRF report (Carlson & Walburger, 2007) were unable to be contacted, using only utilities that provided electricity data to all three phases was the most accurate option. The data set used to form a possible treatment phase model can be seen in Tables D-2 and D-3.

Once again, adjustments to the data were required in order to create a regression model. Similar to the raw water collection model, a value of one was added to the flow rate variables (except the total flow) in order to allow for a value of zero. The unit of kGD was again utilized for flow rate variables for the same reason as in the raw water collection phase. For the various treatment schemes and individual treatment steps a system of one and zero was adopted to be used as an on/off switch for each variable. A value of one corresponds to the given water utility utilizing the corresponding treatment process or step while a value of zero indicates that technology is not used. These values were not transformed when evaluating a regression model, but were left as a one or zero.

The $\log_{10}$ transformation was assessed first and the lasso selection method was used to identify significant independent variables. The only variable identified was $\log_{10}$(total average flow). Upon forming a regression model using $\log_{10}$(total average flow) as the independent variable, one data point, CA030, was shown to have a substantial amount of influence on the regression coefficients. This data point was deleted so the model did not rely heavily on a single data point. The lasso selection method was run again with identical results. A regression model was formed again with poor results. The model has a low R^2 value of 0.51 while also illustrating no obvious data points for further deletion.

To form a more useful model, a new approach was attempted. The majority of treatment plants are either conventional or direct filtration, so all other water utilities were deleted to narrow the focus of the model formation. The following treatment schemes (and utilities) were deleted: slow sand filtration (IL006, TN001, and WI003), membrane filtration (CU25), and nanofiltration (CA018). The lasso selection method once again showed $\log_{10}$(total average flow) as the only significant variable, with the regression model results not improving over the last model. A model was then attempted using the independent variables $\log_{10}$(total average flow) and all the individual treatment steps listed previously. This resulted in a little improvement of the model, increasing the R^2 value to only 0.59.

The last step taken to provide a useful treatment electricity prediction model was to form a model for only conventional treatment plants being that they are the most common treatment process used. The lasso selection method was again utilized and the following independent variables were identified:

1. Log_{10}(Average Groundwater Flow)
2. Log_{10}(Average Surface Water Flow)
3. Log_{10}(Total Average Flow)
4. Aeration

A regression model was formed using these independent variables. The result was another poor model with an R^2 value of 0.54 and no obvious option for improvement.

It has been concluded that an acceptable electricity prediction model for the treatment process could not be formed using the current data set. One possible reason is that even with the attempts made to ensure only electricity for the treatment process was analyzed, there was no way to confirm this, and therefore some electricity from another phase of the water utility may have been included. For example, a utility may have provided the electrical demand of its distribution pump stations under the finished water distribution phase, while having the electrical demand of the high service pumps remain in the number entered under the treatment phase. These pumps are at the beginning of the distribution system and are often responsible for the majority of the distribution electrical demand, but are located on the same site (and often same electrical meter) as the treatment plant. This situation would have qualified the utility for inclusion in the treatment phase model formation. The main issue stems from the inability of most treatment plants to accurately track energy consumption for different sections of the process. Developing an accurate treatment process energy prediction model would require improved energy accounting by water utilities. To include some form of electrical demand prediction in the GHG emissions accounting tool, literature data were utilized. More specifically, the data shown in Table 4.1, which corresponds to Figure 2.2, were used in the tool.

5.5 Finished Water Distribution

The last electricity prediction model to be developed was for the finished water distribution phase of the water utility. Once again, the potential independent variables to be used in forming the model needed to be determined. The independent variables selected were total average flow, length of water mains, distribution pumping hp, average distribution pressure, and elevation change.

Next, the survey data were narrowed to the water utilities that provided electricity use for the finished water distribution phase. If independent variables, such as pumping horsepower, were left blank by the utility that plant would simply be ignored by SAS when forming a regression model. The data used to form the finished water distribution model are presented in Table D-4.

Similar to the previous data, a change was required of the finished water distribution data in order to use the $\log_{10}$ transformation. A value of one was added to the length of water mains and elevation change variables in order for a value of zero to be a valid entry from those variables. The other independent variables should not be zero so they were left unchanged. Before running SAS, six water utilities were deleted from the data set. Four (CA038, TX008, VT003, and WY001) were deleted because they indicated zero pumping hp but listed a non-negligible electricity use. As in the raw water collection phase, the only major electricity consumption source in finished water distribution is pumping, so these data points were not logical. The additional two utilities (IL002 and IL003) were deleted because of a likely entry error. The utilities had identical data but listed different flow rates. It is likely that they were two different plants that fed a single distribution system.

The first regression model to be evaluated utilized the $\log_{10}$ transformation. The lasso selection method was used and the following independent variables were selected:

1. Log_{10}(Total Average Flow)
2. Log_{10}(Distribution Pumping HP)
3. Log_{10}(Elevation Change)
4. Log_{10}(Total Average Flow)* Log_{10}(Distribution Pumping HP)
5. Log_{10}(Distribution Pumping HP)* Log_{10}(Elevation Change)

A regression model was then formed using these independent variables. Upon analyzing the results, two data points were found to be unusual and were deleted. The first utility

(TN001) only listed an electricity use of 151.54 kWh/yr, which is too low to be feasible. The second utility (NC010) reported an abnormally large electricity usage that is likely due to an entry error. The lasso selection method was then run again and selected all of the independent variables as well as a number of interactions (independent variables multiplied together). The regression model formed using this many variables caused multi-collinearity problems. Centering was used to remove this issue as well as to help identify which independent variables are significant. After this process, three independent variables were identified: Log_{10}(Total Average Flow), Log_{10}(Distribution Pumping HP), and Log_{10}(Elevation Change). A new regression model was formed using these three variables and two more data points were identified for deletion. Plants IL006 and MD002 both had electricity usages that were too low, especially given their hp values.

The lasso selection method was then run again to identify independent variables, with the following three being selected:

1. Log_{10}(Total Average Flow)
2. Log_{10}(Distribution Pumping HP)
3. Log_{10}(Total Average Flow)* Log_{10}(Distribution Pumping HP)

A new regression model was formed using these three independent variables. One data point (NC004) was found to have an abnormally large amount of influence on the model while also listing low values for flow and pumping hp considering the electrical demand. This utility was deleted and the regression model was run again. Another data point (CA016) was identified as a possible outlier due to its large residual and large hp value for the given electrical demand. The model was also again showing multi-collinearity problems, which centering was used to correct. After this process, two independent variables were identified as significant: Log_{10}(Total Average Flow) and Log_{10}(Distribution Pumping HP). A regression model was once again formed using these variables. One additional data point (CA042) was deleted because of its large residual and small electrical demand considering the flow and pumping hp listed. This final model provided a good fit for the data. The residuals were evenly distributed across a fairly constant band. Although there were individual data points with influence on the model, no single point dominated.

The final $\log_{10}$ model for finished water distribution is:

$$Log_{10}(Electricity\ [kWh/yr]) =$$
$$3.6538 + 0.4259 * Log_{10}(Total\ Average\ Flow\ [MGD]) + \qquad (4)$$
$$0.6590 * Log_{10}(Finished\ Water\ Distribution\ Pumping\ HP + 1)$$

The model has an R^2 value of 0.69 and a graph comparing the actual electricity use and the predicted electricity use is shown in Figure 5.5.

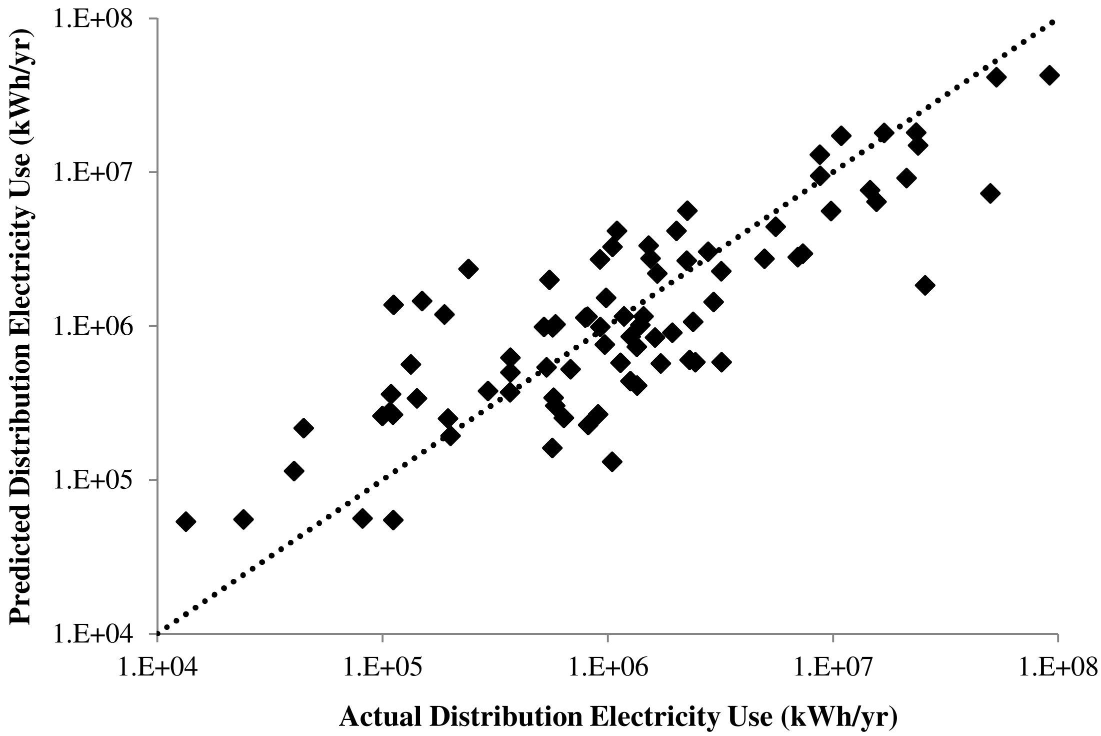

Figure 5.5 Illustration of the actual finished water distribution electricity use versus the value of the electricity use predicted by the regression model (n=86).

A second finished water distribution regression model was investigated using a SQRT transformation of the data. In addition to the original six deleted data points, four additional points were deleted before running SAS due to the reliability issues illustrated in forming the $\log_{10}$ regression model. These points were IL006, MD002, NC010, and TN001. The lasso selection method was again utilized and the following independent variables were selected:

1. SQRT(Total Average Flow)
2. SQRT(Length of Water Mains)
3. SQRT(Distribution Pumping HP)
4. SQRT(Total Average Flow)*SQRT(Distribution Pumping HP)

5. SQRT(Length of Water Mains)*SQRT(Distribution Pumping HP)

SAS was then used to form a regression model using these five independent variables. Two data points (MO002 and VA005) were shown to have very large residuals and were deleted. The lasso selection method chose identical independent variables and the regression model formation was run again. There were two data points (WI001 and CU018) which were identified as having large influences on the model coefficients. These two points lie on the extreme upper end of the range and were deleted so the model did not rely so heavily on two points. The lasso selection method was run again and identified the following independent variables:

1. SQRT(Total Average Flow)
2. SQRT(Distribution Pumping HP)
3. SQRT(Total Average Flow)*SQRT(Distribution Pumping HP)

The model illustrated problems with multi-collinearity. Centering was once again used to handle this problem and also illustrate that SQRT(Total Average Flow) *SQRT(Distribution Pumping HP) was the least significant independent variable. The regression model was run again with this variable removed to prevent future multi-collinearity problems. The SQRT transformation poorly models the larger electricity users compared to the $\log_{10}$ transformation. To confirm that the regression model using the $\log_{10}$ transformation was a better model for the finished water distribution phase, the sum of squared errors was compared for both transformations. The model using the $\log_{10}$ transformation had a lower sum of squared errors ($5.5*10^{15}$ versus $6.3*10^{15}$ for the SQRT transformation), verifying it as the superior model.

CHAPTER SIX

IMPLEMENTATION OF THE GHG EMISSIONS ACCOUNTING TOOL

6.1 Data and Results from Water Utility Testing

To implement and test the GHG emissions accounting tool, seven water utilities located in Georgia, North Carolina, and South Carolina were visited. These utilities provided the input data for the program as well as feedback on the tool itself. In order to determine GHG emissions from electricity, the emission factors from the corresponding EPA subregion were used for all of the water utilities. The participating utilities were identified as Utility A, B, C, etc. in this section.

The first water utility, Utility A, produces an average flow of 4.21 MGD and has two treatment plants located next to each other, which use a common raw water collection and finished water distribution system. The process train used at Utility A is conventional treatment with on-site hypochlorite generation. The annual electricity and stationary combustion fuel usage for Utility A can be seen in Table 6.1. The annual chemical usage as well as the fuel usage and mileage from the vehicle fleet are presented in Table F-1 and F-2, respectively. The utility operates partially as a wholesaler, which means the responsibility for the distribution pumping and final water usage (fuel usage to check meters, make repairs, etc.) falls on the purchasing entities instead of the utility. This causes lower emissions because of the decreased electricity and fuel demand associated with operating fewer pumps and vehicles. The carbon inventory of Utility A was calculated to be 2,299,854 kg CO_2-eq./yr or 1,496 kg CO_2-eq./MG. The carbon footprint of Utility A was determined to be 2,546,326 kg CO_2-eq./yr or 1,656 kg CO_2-eq./MG.

Table 6.1 Annual electricity and stationary combustion fuel usage for Utility A.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	1330200	34.3	0
Treatment Process	2079309*	0	0
Finished Water Distribution	1032594	0	0
Buildings/Fleet/Other	0	0	283.2

*The electricity listed under the treatment phase includes the high service distribution pumps and the administration buildings.

The next water utility, Utility B, produces an average flow of 83.4 MGD. Utility B has two treatment plants separated from each other, which have individual raw water collection pumps but a common finished water distribution system. Utility B utilizes conventional treatment with one plant using on-site hypochlorite generation. The annual electricity and stationary combustion fuel usage for Utility B are shown in Table 6.2. The annual chemical usage as well as the fuel usage and mileage from the vehicle fleet can be seen in Table F-1 and F-3, respectively. The carbon inventory of Utility B was calculated to be 49,730,174 kg CO_2-eq./yr or 1,633 kg CO_2-eq./MG. The carbon footprint of Utility B was determined to be 53,849,655 kg CO_2-eq./yr or 1,768 kg CO_2-eq./MG.

Table 6.2 Annual electricity and stationary combustion fuel usage for Utility B.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	24098121	0	0
Treatment Process	47578837*	0	0
Finished Water Distribution	0	0	0
Buildings/Fleet/Other	263393	0	7733

*The electricity listed under the treatment phase includes the distribution pumps.

Utility C produces an average flow of 74.7 MGD and has two treatment plants separated from each other, which have individual raw water collection pumps but a common finished water distribution system. Utility C has a direct filtration with ozonation treatment process. The annual electricity and stationary combustion fuel usage for Utility C are presented in Table 6.3. The annual chemical usage can be seen in Table F-1. The fuel usage and mileage from the vehicle fleet were not provided. The carbon inventory of Utility C was calculated to be 40,185,724 kg CO_2-eq./yr or 1,473 kg CO_2-eq./MG. The carbon footprint of Utility C was determined to be 47,887,598 kg CO_2-eq./yr or 1,755 kg CO_2-eq./MG.

Table 6.3 Annual electricity and stationary combustion fuel usage for Utility C.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	9859432	0	0
Treatment Process	45063794*	0	0
Finished Water Distribution	4000703	0	0
Buildings/Fleet/Other	0	0	0

*The electricity listed under the treatment phase includes the high service distribution pumps from both plants, the raw water collection pumps from one plant, and the administrative buildings.

Utility D produces an average flow of 55.4 MGD with one treatment plant which uses a conventional treatment process train. The annual electricity and stationary combustion fuel usage for Utility D can be seen in Table 6.4. The annual chemical usage was not provided. The fuel usage from the vehicle fleet is shown in Table F-4, but the annual mileage from the vehicle fleet was not provided. The carbon inventory of Utility D was calculated to be 18,218,588 kg CO_2-eq./yr or 900 kg CO_2-eq./MG. The carbon footprint of Utility C is the same as the carbon inventory because no chemical usage data was provided.

Table 6.4 Annual electricity and stationary combustion fuel usage for Utility D.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	0	0	0
Treatment Process	28086457*	0	0
Finished Water Distribution	2273254	0	0
Buildings/Fleet/Other	1458424	0	4128

*The electricity listed under the treatment phase includes the raw water collection and high service distribution pumps.

The next utility to be evaluated is Utility E which produces an average flow of 60.3 MGD. Utility E has two treatment plants separated from each other that have individual raw water collection pumps but a common finished water distribution system. The annual electricity and stationary combustion fuel usage for Utility E can be seen in Table 6.5. The values for fuel usage are zero because they were not provided. The annual chemical usage along with the vehicle fleet fuel usage and mileage were also not provided. The carbon inventory of Utility E was calculated to be 21,186,389 kg CO_2-eq./yr or 962 kg CO_2-eq./MG. The carbon footprint of Utility E is the same as the carbon inventory because no chemical usage data was provided.

Table 6.5 Annual electricity and stationary combustion fuel usage for Utility E.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	0	0	0
Treatment Process	41531000*	0	0
Finished Water Distribution	0	0	0
Buildings/Fleet/Other	0	0	0

*The electricity listed under the treatment phase includes the entire utility.

Utility F produces an average flow of 34 MGD. Utility F has two treatment plants; however, data for only one plant was provided. The two plants have separate raw water collection pumps but feed a common distribution system. Therefore, the GHG emissions associated with the shared distribution systems as well as the shared vehicle fleet and administrative offices were not included. The treatment plant that was evaluated uses a conventional treatment process. The annual electricity and stationary combustion fuel usage for Utility F are presented in Table 6.6. The annual chemical usage can be seen in Table F-1; while the fuel usage and annual mileage from the vehicle fleet associated with this plant are illustrated in Table F-5. The carbon inventory of Utility F was calculated to be 16,678,073 kg CO_2-eq./yr or 1,343 kg CO_2-eq./MG. The carbon footprint of Utility F was determined to be 20,315,870 kg CO_2-eq./yr or 1,636 kg CO_2-eq./MG.

Table 6.6 Annual electricity and stationary combustion fuel usage for Utility F.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	6798000	693.5	0
Treatment Process	25490000*	1387	0
Finished Water Distribution	0	0	0
Buildings/Fleet/Other	0	0	0

*The electricity listed under the treatment phase includes the raw water collection and high service distribution pumps.

The last water utility to be evaluated is Utility G and produces an average flow of 17.5 MGD. Utility G has one treatment plant which uses conventional treatment with superpulsators. The utility operates solely as a wholesaler, which decreases the GHG emissions associated with the distribution system and vehicle fleet as those will fall under the responsibility of those that purchase the water. The annual electricity and stationary combustion fuel usage for Utility G can be seen in Table 6.7. The annual chemical usage is shown in Table F-1; while the fuel usage and mileage from the vehicle fleet are presented in Table F-6. The carbon inventory of Utility G was calculated to be 5,734,619 kg CO_2-eq./yr or 897 kg CO_2-eq./MG. The carbon footprint of Utility G was determined to be 7,189,640 kg CO_2-eq./yr or 1,125 kg CO_2-eq./MG.

Table 6.7 Annual electricity and stationary combustion fuel usage for Utility G.

	Energy Usage		
	Electricity	Diesel	Natural Gas
Phase of Utility	kWh/yr	MMBtu/yr	MMBtu/yr
Raw Water Collection	4538400	0	0
Treatment Process	2305800	468	0
Finished Water Distribution	3952800	0	0
Buildings/Fleet/Other	275400	0	0

6.2 GHG Emissions Data Analysis

The best option to compare the water utilities to each other is to use the carbon inventory. The reason for this is that not every chemical used at the various utilities was available in the GHG emissions accounting tool, leaving the possibility that one utility may have a larger footprint than could have been calculated. A visual comparison of the normalized carbon inventories is presented in Figure 6.1. The average carbon inventory for the utilities that tested the GHG emissions accounting tool was 1240 kg CO_2-eq./MG. While only limited analysis can be done with seven data points, a few observations can be pointed out in Figure 6.1. First, an economy of scale effect does not seem to be in place with this data set as the smallest and largest utilities in terms of flow actually have fairly similar carbon inventories. A hypothesis can be made as to why the three lowest carbon inventories were from Utility D, E, and G. Utility D explained that it strives to be as progressive and environmentally friendly as possible, which would lead to decreased energy use and therefore a lower carbon inventory. Utility E did not include any data on fuel usage and emissions from a vehicle fleet, which may have caused the lower inventory. Utility G operates completely as a wholesaler so it lacks the GHG emissions from a large distribution system and vehicle fleet that most of the other utilities have.

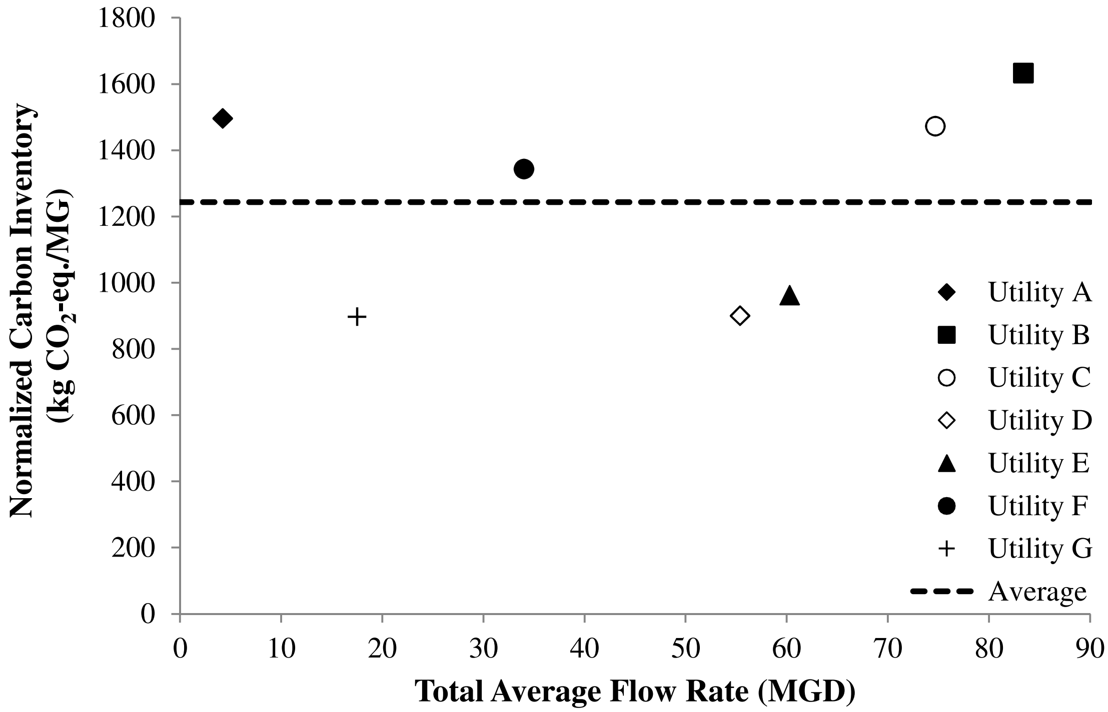

Figure 6.1 Normalized carbon inventories of the water utilities that tested the GHG emissions accounting tool.

Another observation that bears comment is that two of the seven utilities tested have an annual GHG emissions amount that exceeded the threshold of the EPA reporting rule discussed in Section 2.8.3. The value reported to the EPA would be the carbon inventory, of which both Utility B and C exceeded the 25,000 metric tons of CO_2-eq./yr limit with values of 49,700 and 40,200 metric tons of CO_2-eq./yr, respectively. If an average carbon inventory of 1240 kg CO_2-eq./MG is assumed, water utilities with a flow rate greater than 55.2 MGD will have annual GHG emissions greater than the EPA reporting rule limit. The electrical grid being utilized can have a significant effect on both the average carbon inventory and the average flow rate required to exceed the EPA reporting rule threshold. To analyze this effect, the seven utilities were also tested using the three lowest and highest GHG emitting EPA subregions as well as the national average emission factors. The results of this analysis are presented in Table 6.8.

Table 6.8 Average carbon inventory and flow rate required to exceed EPA reporting rule limit of the water utilities tested when using the three highest and lowest GHG emitting EPA subregions and national average emission factors.

EPA Subregion Acronym	Carbon Inventory (kg CO_2-eq./MG)	Flow Rate to Exceed EPA Reporting Rule (MGD)
RMPA	2190	31.3
SPNO	1805	37.9
SRMW	1786	38.3
National Grid	1311	52.2
CAMX	698	98.1
NYUP	698	98.1
AKMS	554	123.5

The only source of literature data found that could be used to compare with the testing results comes from LCA studies. As the LCA studies included more than what is measured by the carbon inventory, the carbon footprint of the water utilities was the more appropriate value to compare. The comparison between the data from Utilities A-G and the literature data can be seen in Figure 6.2. The reason the literature data was presented as horizontal lines and not data points is because the LCA studies did not provide flow rate data, but GHG emissions based on a functional unit. The literature data represent two extremes of carbon footprint values in that Friedrich (2002) only took into account the treatment plant itself and Stokes and Horvath (2006) were analyzing importing water over long distances. Considering these limitations, it was encouraging that all of the utilities evaluated fell in between the limits of the literature values.

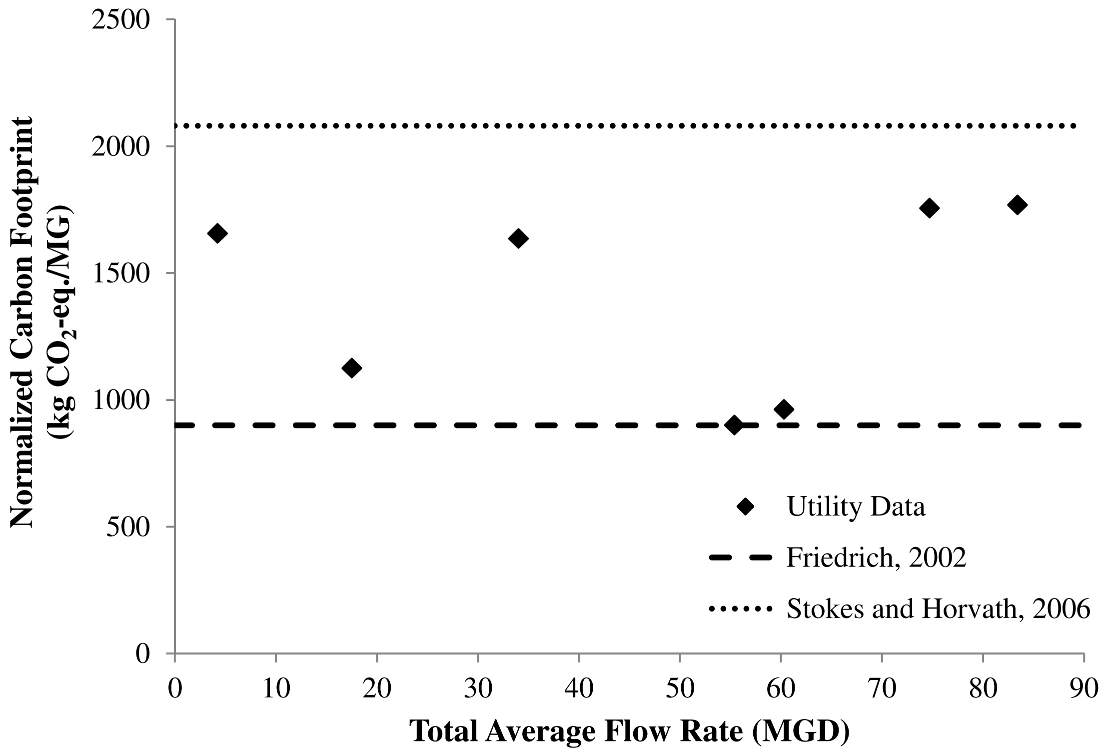

Figure 6.2 Comparison between the carbon footprints of Utilities A-G and literature data [literature data adapted from (Friedrich, 2002; Stokes & Horvath, 2006)].

The only utility that can fully illustrate the sources of GHG emissions is Utility G because it was the only utility to be able to separate the four different phases. The relative amounts of GHG emissions from each phase are presented in Figure 6.3. The major contributor to the carbon inventory of Utility G is pumping in that raw water collection and finished water distribution account for 75% of the emissions. Utility G operates solely as a wholesaler so it is expected that finished water distribution would account for more emissions for utilities that operate a larger distribution network. The other source type of GHG emissions to analyze are Scopes 1, 2, and 3. For the utilities tested, Scope 2 emissions dominated, making up at least 80% of the carbon footprint.

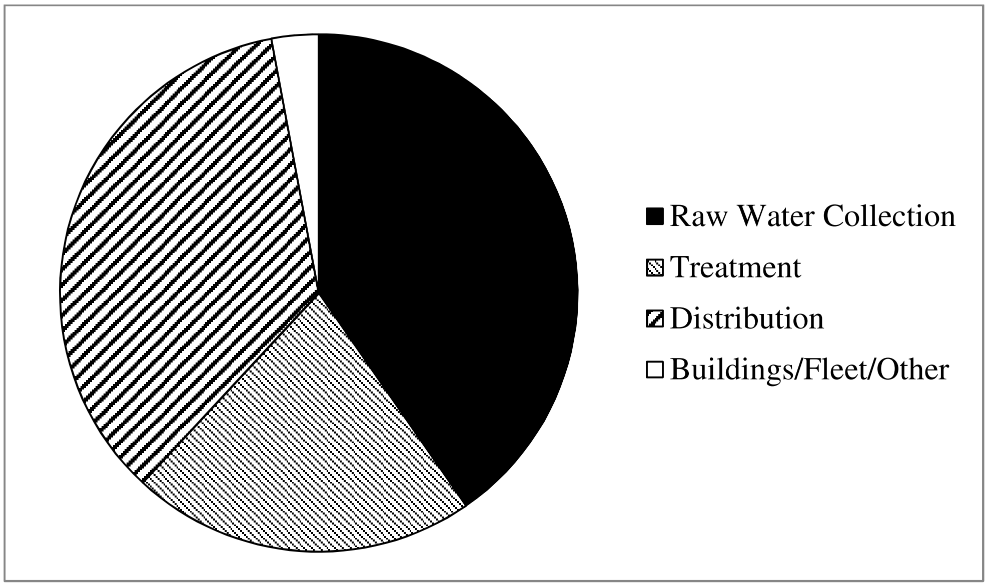

Figure 6.3 Relative amounts of GHG emissions from each phase of Utility G.

6.3 Energy Use Prediction Equations Evaluation

While collecting data to evaluate the GHG emissions accounting tool, data were also gathered to test the energy prediction equations that were developed and described in Chapter 5. The results of these tests are displayed in Table 6.9. The testing was done for separate phases of each water utility whenever possible. If a utility was not able to separate treatment and distribution electricity usages, for example, then that combination was compared with the combined prediction results for those two phases. Though the sample size is small, one thing to note is that the predictions for the treatment phase or treatment and distribution phases were low by 60-80%. The treatment phase prediction function appeared to be the weakest because of the inability to fit a regression model and also having to rely on a single source of literature data for predictions. These results somewhat confirmed this conclusion. One problem with the literature data used in the program is that they lack data for solids/sludge handling, which could help explain some of the difference in the predictions because the solids handling equipment can include large energy users such as thickeners (centrifuges, etc.) and additional pumping. A larger data set would be required to more accurately evaluate the performance of the energy use predictions equations. Even with a larger data set and improved models, there is a limit to how accurately energy use can be predicted. A prediction model will never be as accurate as measured data.

Table 6.9 Results of energy use prediction equation testing.

Utility Phase	Utility	Actual Electricity Use kWh/yr	Predicted Electricity Use kWh/yr	Percent Difference
Raw Water Collection	Utility A	1,330,000	1,172,000	-12%
Raw Water Collection	Utility B	24,098,000	15,387,000	-36%
Raw Water Collection	Utility F	6,798,000	7,912,000	16%
Raw Water Collection	Utility G	4,538,000	6,684,000	47%
Treatment	Utility G	2,306,000	668,000	-71%
Treatment & Distribution	Utility A	3,112,000	656,000	-79%
Treatment & Distribution	Utility B	47,579,000	15,818,000	-67%
Treatment & Distribution	Utility F	25,490,000	8,827,000	-65%
Distribution	Utility G	3,953,000	3,209,000	-19%
Entire Utility	Utility D	30,360,000	22,448,000	-26%
Entire Utility	Utility E	41,531,000	29,333,000	-29%

6.4 Water-Energy Nexus Evaluation

The data collected from the seven utilities were also used to test the water-energy nexus portion of the accounting tool. The results of this analysis are presented in Table 6.10. The water consumed in generating electricity for the water utilities represented a small percentage (0.08%-0.14%) of the water produced by the water utility. This produced net water production values almost identical to the total average flow of the water utility.

Table 6.10 Results of the water-energy nexus evaluation.

	Water Consumption				Net Water
Utility	gal/yr	MGD	% of Production	Total Average Flow Rate (MGD)	Production (MGD)
Utility A	2,192,584	0.0060	0.14%	4.21	4.20
Utility B	34,104,379	0.0934	0.11%	83.4	83.31
Utility C	27,933,753	0.0765	0.10%	74.734	74.66
Utility D	15,705,158	0.0430	0.08%	55.37	55.33
Utility E	20,499,345	0.0561	0.09%	60.3	60.24
Utility F	15,937,080	0.0436	0.13%	34	33.96
Utility G	5,465,242	0.0150	0.09%	17.5	17.49

6.5 Feedback for the GHG Emissions Accounting Tool

Overall, the accounting tool received a positive reception from the seven water utilities that tested it. The program was the first tool of its kind that the utilities have seen. In order to improve the ease of use, an instructions page was recommended to be added at the beginning of the program. Another suggestion was to add references for the emission factors used in the program in order to validate that the program uses reputable data. The utilities also listed the chemicals used at their treatment plants that were not listed in the program, such as fluoride (sodium fluorosilicate and fluorosilicic acid), phosphate, powdered activated carbon, sulfuric acid, sodium chlorite, and sodium chloride.

CHAPTER SEVEN

CONCLUSIONS AND RECOMMENDATIONS

The important conclusions for each objective of this study were as follows:

Main objective: Develop an accounting tool that will allow for water utilities to calculate their GHG emissions.

- The accounting tool was created to calculate the GHG emissions of a water utility. It was designed to be flexible enough for use by a wide range of utility sizes, treatment processes, and locations in the United States.

Sub-objective 1: Create a program to serve as the shell of the GHG emissions accounting tool.

- A comprehensive literature review was conducted to compile all available data and equations relating to GHG emissions from water utilities.
- The information gathered was used to develop a program, which contains all the necessary data input cues, formulas, and emission factors for water utilities to calculate their carbon inventory and footprint.

Sub-objective 2: Develop energy use prediction equations for different portions of the water production process.

- The survey data obtained to form the prediction equations had an average energy use of 3.1 kWh/1000 gal.

- The $\log_{10}$ transformation of the data was found to be the superior option compared to the SQRT transformation for all of the regression models formed because the SQRT transformation produced an uneven distribution and was not able to accurately model the upper range of electricity usage.
- Two prediction equations were developed for the raw water collection phase, one for water utilities with purchased water flows and one for those without. Both models used total average flow rate and raw water collection pumping hp as independent variables; while the model for utilities with purchased water flows also included that flow as an independent variable. The regression model for utilities with purchased water flows has an R^2 value of 0.87 while the model for those without has an R^2 value of 0.79.
- An accurate regression model for the treatment phase of water production could not be developed with the current data set. In place of a regression model, literature data are used in the GHG emissions accounting tool to provide a prediction of electricity use during treatment.
- A single regression model was developed for the finished water distribution phase of water production with an R^2 value of 0.69. This model included total average flow and finished water distribution pumping hp as the independent variables.
- Most utilities are not equipped to accurately track the energy consumption for different parts of their process, which would be required for more reliable energy prediction equations to be developed, especially for the treatment phase.

Sub-objective 3: Include the water-energy nexus in the GHG emissions accounting tool.

- A water utility is able to determine the water consumed as a result of generating the electricity required to power the utility as well as determine the net water production of the utility. The program determines this information using the electricity entered in the program, the water production rate, and the zip code of the utility.

Sub-objective 4: Test the program using real data at various water utilities.

- Seven water utilities were visited to collect data and test the GHG emissions accounting tool.
- The carbon inventories of the seven utilities averaged 1240 kg CO_2-eq./MG.
- Two of the seven utilities tested exceeded the EPA reporting rule threshold of 25,000 metric tons of CO_2-eq./yr.
- Assuming an average emission rate of 1240 kg CO_2-eq./MG, water utilities with flow rates greater than 55.2 MGD will have GHG emissions greater than the EPA reporting rule limit.
- Using the national average emissions factors, the seven utilities have an average carbon inventory of 1310 kg CO_2-eq./MG. This average would entail utilities with flow rates greater than 52.2 MGD having emissions greater than the EPA reporting rule limit.

- When using the three highest and lowest GHG emitting EPA subregion emission factors, the seven utilities had carbon inventories that ranged from 550 to 2190 kg CO_2-eq./MG. The flow rate required to exceed the EPA reporting rule threshold subsequently ranged from 31.3 to 123.5 MGD.
- The major source of GHG emissions for a utility with conventional treatment is pumping because the raw water collection and finished water distribution phases account for 75% or more of a utility's carbon inventory.
- The carbon footprints of the seven utilities compared favorably to the literature data in previous LCA studies.
- Scope 2 emissions accounted for at least 80% of the carbon footprint for all seven of the utilities tested
- The water consumed in generating electricity for each water utility was less than one percent of the total average flow rate at each corresponding utility.
- Water utilities that tested the program also provided feedback on how to improve the tool itself, which included adding an instructions and references section.

Recommendations for the further development of the GHG emissions accounting tool are as follows:

- The GHG emissions accounting tool should be transitioned from its current form into a web-based program. This would make the program more user friendly and accessible. A web-based program would also provide an improved avenue to gather data over the current method of surveying. The web-based program would simply have to ask the permission of the user to save their data for further study.

- It is vital to keep the eGRID emissions factors up to date. Any updated values published by the EPA need to be added to the program.
- Literature data used to predict the treatment phase electricity usage need to be augmented to include more individual treatment steps. The critical processes to add are those involved in dewatering and solids handling, for example: centrifuges, belt presses, sludge lagoons, etc.
- Chemicals used during the treatment process that were not included in the first version of the accounting tool need to be researched for their associated GHG emissions and added to the program. These include, but are not limited to, fluoride (sodium fluorosilicate and fluorosilicic acid), phosphate, powdered activated carbon, sulfuric acid, sodium chlorite, and sodium chloride.
- If additional electricity usage data are obtained from the web-based program, the energy use prediction equations should be updated to include these additional data points. The treatment phase in particular should be reevaluated to see if an accurate energy prediction equation can be developed using a larger data set.
- To provide a more complete view of the water-energy nexus, the water consumed in producing the various fuels (gasoline, diesel, natural gas, etc.) used by water utilities should be added to the net water production function of the program.

Recommendations for future research are as follows:

- Combining this program with a similar one designed for wastewater utilities, such as the program developed at Clemson University (Hicks, 2010) should be investigated. This would provide a comprehensive tool for combined utilities and improve the assessment of shared assets such as administrative buildings and vehicle fleets.
- A further investigation into the GHG emissions of water utilities should be undertaken. This would prove easier to accomplish if a web-based version of this program was utilized to obtain a larger data set for the water utility characteristics and their GHG emissions. One specific task in this investigation should be to search for common characteristics of water utilities with low GHG emissions in an effort to help other utilities achieve the goal of lowering their own emissions.

Recommendations for water utilities are as follows:

- Data tracking of current and future energy use should be improved. Compiling the energy use data for all aspects of the water utility in one location would assist in any future energy investigations as well as calculating a GHG emissions baseline.
- Improved energy accounting should be implemented when possible. Additional electric and fuel meters would allow utilities to differentiate energy use for different phases of water production.

- Standardization of energy use reporting should be implemented. The four phases used in this project (raw water collection, treatment, finished water distribution, and buildings/fleet/other) offer an appropriate breakdown of utility-wide energy use.

APPENDICES

Appendix A

Compiled Data for Electrical Generation GHG Emissions

Table A.1: Life cycle GHG emissions for natural gas-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Natural Gas (combined cycle)	389	511	450	(Koch, 2000)
Natural Gas (combined cycle)	422	499	461	(Gagnon, 2003)
Natural Gas (combined cycle)			439	(World Energy Council, 2004)
Natural Gas (combined cycle)			433	(World Energy Council, 2004)
Natural Gas (combined cycle)			448	(World Energy Council, 2004)
Natural Gas (combined cycle)			421	(World Energy Council, 2004)
Natural Gas (combined cycle)			440	(World Energy Council, 2004)
Natural Gas (combined cycle)			407	(World Energy Council, 2004)
Natural Gas (combined cycle)			440	(World Energy Council, 2004)
Natural Gas (combined cycle)			411	(World Energy Council, 2004)
Natural Gas (combined cycle)			499	(World Energy Council, 2004)
Natural Gas (combined cycle)			469	(World Energy Council, 2004)
Natural Gas (combined cycle)			443	(L. Gagnon, Belanger, & Uchiyama, 2002)
Natural Gas (combined cycle)			455	(Pacca & Horvath, 2002)
Natural Gas (combined cycle)	400	780	590	(Streimikiene, 2010)
Gas			362	(Krewitt, 1997)
Gas			356	(UKSDC, 2006)
Gas			469	(Meier, 2002)
Gas			385	(UKDTI, 2006)
Gas			450	(Vattenfall AB, 1999)
Gas			400	(British Energy, 2005)
Gas			410	(POST, 2006)

Table A.2: Life cycle GHG emissions for coal-based electricity production.

	GHG Emissions (g CO2-eq./kWh)			
Term Used	Minimum	Maximum	Average	Source
Coal	790	1182	986	(Koch, 2000)
Coal			815	(Krewitt, 1997)
Coal			891	(UKSDC, 2006)
Coal			974	(Meier, 2002)
Coal			990	(CRIEPI, 1995)
Coal			755	(UKDTI, 2006)
Coal			980	(Vattenfall AB, 1999)
Coal			900	(British Energy, 2005)
Coal			810	(POST, 2006)
Coal			932	(World Energy Council, 2004)
Coal			803	(World Energy Council, 2004)
Coal			766	(World Energy Council, 2004)
Coal			500	(World Energy Council, 2004)
Coal			860	(World Energy Council, 2004)
Coal			1085	(World Energy Council, 2004)
Coal			980	(World Energy Council, 2004)
Coal			834	(World Energy Council, 2004)
Coal			1026	(World Energy Council, 2004)
Coal			960	(World Energy Council, 2004)
Coal			972	(World Energy Council, 2004)
Coal			1075	(World Energy Council, 2004)
Coal			1010	(World Energy Council, 2004)
Coal			823	(World Energy Council, 2004)
Coal			959	(World Energy Council, 2004)
Coal			757	(World Energy Council, 2004)
Coal			847	(World Energy Council, 2004)
Coal			975	(Varun, Bhat, & Prakash, 2009)
Coal	960	1050	1005	(L. Gagnon, et al., 2002)
Coal			765	(Pacca & Horvath, 2002)
Coal	750	1250	1000	(Streimikiene, 2010)

Table A.3: Life cycle GHG emissions for oil-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Oil	519	1190	855	(Dones, Heck, & Hirschberg, 2003)
Oil			742	(Varun, et al., 2009)
Oil	500	1200	850	(Streimikiene, 2010)
Diesel	649	787	718	(Luc Gagnon, 2003)
Diesel			778	(L. Gagnon, et al., 2002)
Heavy Oil	841	999	920	(Gagnon, 2003)
Heavy Oil			778	(L. Gagnon, et al., 2002)
Heavy Fuel Oil			866	(World Energy Council, 2004)
Heavy Fuel Oil			777	(World Energy Council, 2004)
Heavy Fuel Oil			774	(World Energy Council, 2004)
Heavy Fuel Oil			825	(World Energy Council, 2004)
Heavy Fuel Oil			657	(World Energy Council, 2004)

Table A.4: Life cycle GHG emissions for nuclear-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Nuclear	2	59	31	(Koch, 2000)
Nuclear	8	11	10	(Dones, et al., 2003)
Nuclear	6	16	11	(Gagnon, 2003)
Nuclear			20	(Krewitt, 1997)
Nuclear			16	(UKSDC, 2006)
Nuclear			15	(Meier, 2002)
Nuclear			21	(CRIEPI, 1995)
Nuclear	11	22	17	(UKDTI, 2006)
Nuclear			6	(Vattenfall AB, 1999)
Nuclear			5	(British Energy, 2005)
Nuclear	3	5	4	(POST, 2006)
Nuclear			40	(World Energy Council, 2004)
Nuclear			3	(World Energy Council, 2004)
Nuclear			3	(World Energy Council, 2004)
Nuclear			12	(World Energy Council, 2004)
Nuclear			24.2	(Varun, et al., 2009)
Nuclear			15	(L. Gagnon, et al., 2002)

Table A.5: Life cycle GHG emissions for hydroelectric-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Hydroelectric	2	48	25	(Koch, 2000)
Hydroelectric	3	27	15	(Dones, et al., 2003)
Hydroelectric			18	(CRIEPI, 1995)
Hydroelectric			3	(Vattenfall AB, 1999)
Hydroelectric			40	(Pacca & Horvath, 2002)
Hydro with Reservoir	10	33	22	(Gagnon, 2003)
Hydro with Reservoir			10	(POST, 2006)
Hydro with Reservoir	8	15	12	(World Energy Council, 2004)
Hydro with Reservoir	3.5	6.5	5	(World Energy Council, 2004)
Hydro with Reservoir	10	19	15	(World Energy Council, 2004)
Hydro with Reservoir			15	(L. Gagnon, et al., 2002)
Hydro Run-of-River	3	4	3.5	(Gagnon, 2003)
Hydro Run-of-River			2	(POST, 2006)
Hydro Run-of-River			33	(World Energy Council, 2004)
Hydro Run-of-River			5.1	(World Energy Council, 2004)
Hydro Run-of-River			4	(World Energy Council, 2004)
Hydro Run-of-River			2	(L. Gagnon, et al., 2002)

Table A.6: Life cycle GHG emissions for biomass-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Biomass Forestry Wastes Combustion	15	101	58	(Koch, 2000)
Forest Waste Combustion	0	14	7.0	(Gagnon, 2003)
Grass Direct Combustion			80	(POST, 2006)
Large Scale Wood Chip Combustion	76.0	83.3	79.6	(Streimikiene, 2010)
Biomass			118	(L. Gagnon, et al., 2002)
Integrated Gasification Combined Cycle			36	(World Energy Council, 2004)
Integrated Gasification Combined Cycle			17.7	(World Energy Council, 2004)
Integrated Gasification Combined Cycle			15.1	(World Energy Council, 2004)
Integrated Gasification Combined Cycle			49	(World Energy Council, 2004)
Wood Chip Gasification			25	(POST, 2006)
Large Scale Wood Chip Gasification	21.6	29.0	25.3	(Streimikiene, 2010)
Large Scale Biomass (wood chips) CHP	21.6	36.0	28.8	(Streimikiene, 2010)
Small Scale Biomass (wood chips gasification) CHP	10.8	21.6	16.2	(Streimikiene, 2010)
Biogas Cogeneration			78	(Varun, et al., 2009)
Wood Cogeneration	92	156	124	(Dones, et al., 2003)

Table A.7: Life cycle GHG emissions for wind-based electricity production.

	GHG Emissions (g CO_2-eq./kWh)			
Term Used	Minimum	Maximum	Average	Source
Wind	14	21	18	(Dones, et al., 2003)
Wind	9	20	15	(Gagnon, 2003)
Wind			7	(Krewitt, 1997)
Wind			14	(Meier, 2002)
Wind			37	(CRIEPI, 1995)
Wind	11	37	24	(UKDTI, 2006)
Wind			6	(Vattenfall AB, 1999)
Wind	4	5	5	(POST, 2006)
Wind			12.2	(World Energy Council, 2004)
Wind			14.5	(World Energy Council, 2004)
Wind			22	(World Energy Council, 2004)
Wind			8.4	(World Energy Council, 2004)
Wind			8.2	(World Energy Council, 2004)
Wind			10.3	(World Energy Council, 2004)
Wind			9.1	(World Energy Council, 2004)
Wind			7.4	(World Energy Council, 2004)
Wind			12.4	(World Energy Council, 2004)
Wind			9.1	(World Energy Council, 2004)
Wind			16.5	(Varun, et al., 2009)
Wind			10	(Varun, et al., 2009)
Wind			11	(Varun, et al., 2009)
Wind			9	(L. Gagnon, et al., 2002)
Wind			10	(Pacca & Horvath, 2002)

Table A.8: Life cycle GHG emissions for solar-based electricity production.

Term Used	GHG Emissions (g CO_2-eq./kWh) Minimum	Maximum	Average	Source
Solar Photovoltaic	38	121	80	(Gagnon, 2003)
Solar Photovoltaic			53	(Krewitt, 1997)
Solar Photovoltaic			39	(Meier, 2002)
Solar Photovoltaic			59	(CRIEPI, 1995)
Solar Photovoltaic			50	(Vattenfall AB, 1999)
Solar Photovoltaic	35	58	47	(POST, 2006)
Solar Photovoltaic			104	(World Energy Council, 2004)
Solar Photovoltaic			43	(World Energy Council, 2004)
Solar Photovoltaic			51	(World Energy Council, 2004)
Solar Photovoltaic			44	(World Energy Council, 2004)
Solar Photovoltaic			45	(World Energy Council, 2004)
Solar Photovoltaic			12.5	(World Energy Council, 2004)
Solar Photovoltaic	21	45	33	(Fthenakis & Alsema, 2006)
Solar Photovoltaic	27	59	43	(Fthenakis & Alsema, 2006)
Solar Photovoltaic			50	(Sherwani, Usmani, & Varun, 2010)
Solar Photovoltaic			39	(Sherwani, et al., 2010)
Solar Photovoltaic			34.3	(Sherwani, et al., 2010)
Solar Photovoltaic			15.6	(Sherwani, et al., 2010)
Solar Photovoltaic			60	(Sherwani, et al., 2010)
Solar Photovoltaic			64.8	(Sherwani, et al., 2010)
Solar Photovoltaic			44	(Sherwani, et al., 2010)
Solar Photovoltaic			12	(Sherwani, et al., 2010)
Solar Photovoltaic			53.4	(Sherwani, et al., 2010)
Solar Photovoltaic			26.4	(Sherwani, et al., 2010)
Solar Photovoltaic			72.4	(Sherwani, et al., 2010)
Solar Photovoltaic			12.1	(Sherwani, et al., 2010)
Solar Photovoltaic			9.4	(Sherwani, et al., 2010)
Solar Photovoltaic			13	(L. Gagnon, et al., 2002)
Solar Photovoltaic			100	(Pacca & Horvath, 2002)

Appendix B

Supplemental Information for Chapter 4

Table B.1: EPA subregion electricity emission factors [adapted from (USEPA, 2010)].

eGRID Subregion Acronym	CO_2 Emission Rate lb/MWh	CH_4 Emission Rate lb/MWh	N_2O Emission Rate lb/MWh
AKGD	1284.720	0.0271	0.0074
AKMS	535.730	0.0227	0.0045
AZNM	1252.610	0.0188	0.0166
CAMX	681.010	0.0283	0.0062
ERCT	1252.570	0.0178	0.0140
FRCC	1220.110	0.0412	0.0153
HIMS	1343.820	0.1352	0.0217
HIOA	1620.760	0.0911	0.0209
MROE	1692.320	0.0288	0.0291
MROW	1771.520	0.0295	0.0300
NEWE	827.950	0.0770	0.0152
NWPP	858.790	0.0163	0.0136
NYCW	704.800	0.0262	0.0034
NYLI	1418.740	0.0905	0.0131
NYUP	680.490	0.0174	0.0099
RFCE	1059.320	0.0274	0.0170
RFCM	1651.110	0.0326	0.0278
RFCW	1551.520	0.0184	0.0259
RMPA	2187.410	0.0267	0.0335
SPNO	1798.710	0.0212	0.0292
SPSO	1624.030	0.0245	0.0224
SRMV	1004.100	0.0218	0.0112
SRMW	1779.270	0.0206	0.0296
SRSO	1495.470	0.0236	0.0246
SRTV	1540.850	0.0199	0.0255
SRVC	1118.410	0.0223	0.0191

Table B.2: United States national average electricity emission factors [adapted from (USEPA, 2010)].

CO_2 Emission Rate lb/MWh	CH_4 Emission Rate lb/MWh	N_2O Emission Rate lb/MWh
1299.53	0.02514	0.01974

Table B.3: Average life cycle GHG emissions from various electricity production methods (data sources can be seen in Appendix A).

Electricity Production Method	Emissions Factor g CO_2-eq./kWh
Coal	901
Natural Gas	438
Oil	795
Nuclear	15
Hydroelectric	13
Biomass	51
Wind	13
Solar	45

Table B.4: Fuel usage GHG emission factors for stationary combustion sources [adapted from (USEPA, 2008b)].

Fuel	Emission Factor		
	CO_2 kg/MMBtu	CH_4 kg/MMBtu	N_2O kg/MMBtu
Natural Gas	53.0567	0.0052709	0.0001054
Propane	63.0667	0.0105419	0.0006325
Liquid Propane	63.1620	0.0105419	0.0006325
Diesel	73.1500	0.0105419	0.0006325
Fuel Oil No. 1	73.1500	0.0105419	0.0006325
Fuel Oil No. 2	73.1500	0.0105419	0.0006325
Fuel Oil No. 4	73.1500	0.0105419	0.0006325
Fuel Oil No. 5 & 6	78.7967	0.0105419	0.0006325
Kerosene	72.3067	0.0105419	0.0006325
Coal (anthracite)	103.6200	0.0105419	0.0015813
Coal (bituminous)	93.4633	0.0105419	0.0015813
Coke	113.6667	0.0105419	0.0015813
Wood	93.8667	0.3162555	0.0042167

Table B.5: GHG emission factors for potable water production specific direct emission sources [adapted from (Huxley, et al., 2009)].

Source	Emission Factor		
	CO_2	CH_4	N_2O
Ozone Generation	-	-	0.11 g N_2O/m^3
GAC Regeneration	[(44/12)*7.5%]/ton	-	-
Reservoir Emissions			
-Boreal	1460 mg/m^2/day	57.2 mg/m^2/day	0.2 mg/m^2/day
-Temperate	525 mg/m^2/day	6.7 mg/m^2/day	0.0 mg/m^2/day
-Subtropical	525 mg/m^2/day	6.7 mg/m^2/day	0.0 mg/m^2/day
-Tropical	5470 mg/m^2/day	136.1 mg/m^2/day	218.8 mg/m^2/day
Sludge Disposal	762 kg/ton	39 kg/ton	-

Table B.6: GHG emission factors from chemical production [adapted from (Tripathi, 2007)].

Chemical	GHG Emissions kg CO_2-eq./MT
Alum	276
Ferric Chloride	77
Ferrous Chloride	77
Chlorine	780
Sodium Hypochlorite	1065
Lime	1264
Polymers	2082
Carbon Dioxide	346
Oxygen	226
Sodium Hydroxide	1376
Ammonia	2400

Table B.7: CO_2 emission factors for mobile combustion sources [adapted from (USEPA, 2008a)].

Fuel	Emission Factors kg CO_2/gallon
Gasoline	8.81
Diesel	10.15
E85	6.05
Ethanol	5.56
Biodiesel	9.46

Table B.8: CH_4 and N_2O emission factors for passenger cars [adapted from (USEPA, 2008a)].

Fuel	Model Year/ Catalytic Control	Emission factors N_2O g/mile	Emission factors CH_4 g/mile
Gasoline	1984-1993	0.0647	0.0704
Gasoline	1994	0.056	0.0531
Gasoline	1995	0.0473	0.0358
Gasoline	1996	0.0426	0.0272
Gasoline	1997	0.0422	0.0268
Gasoline	1998	0.0393	0.0249
Gasoline	1999	0.0337	0.0216
Gasoline	2000	0.0273	0.0178
Gasoline	2001	0.0158	0.011
Gasoline	2002	0.0153	0.0107
Gasoline	2003	0.0135	0.0114
Gasoline	2004	0.0083	0.0145
Gasoline	2005-present	0.0079	0.0147
Diesel	1960-1982	0.0012	0.0006
Diesel	1983-present	0.001	0.0005

Table B.9: CH_4 and N_2O emission factors for light-duty trucks [adapted from (USEPA, 2008a)].

Fuel	Model Year/ Catalytic Control	Emission factors N_2O g/mile	Emission factors CH_4 g/mile
Gasoline	1987-1993	0.1035	0.0813
Gasoline	1994	0.0982	0.0646
Gasoline	1995	0.0908	0.0517
Gasoline	1996	0.0871	0.0452
Gasoline	1997	0.0871	0.0452
Gasoline	1998	0.0728	0.0391
Gasoline	1999	0.0564	0.0321
Gasoline	2000	0.0621	0.0346
Gasoline	2001	0.0164	0.0151
Gasoline	2002	0.0228	0.0178
Gasoline	2003	0.0114	0.0155
Gasoline	2004	0.0132	0.0152
Gasoline	2005-present	0.0101	0.0157
Diesel	1960-1982	0.0017	0.0011
Diesel	1983-1995	0.0014	0.0009
Diesel	1996-present	0.0015	0.001
Ethanol	All	0.067	0.055

Table B.10: CH_4 and N_2O emission factors for heavy-duty trucks [adapted from (USEPA, 2008a)].

Fuel	Model Year/ Catalytic Control	Emission factors N_2O g/mile	CH_4 g/mile
Gasoline	1985-1986	0.0515	0.409
Gasoline	1987	0.0849	0.3675
Gasoline	1988-1989	0.0933	0.3492
Gasoline	1990-1995	0.1142	0.3246
Gasoline	1996	0.168	0.1278
Gasoline	1997	0.1726	0.0924
Gasoline	1998	0.1693	0.0641
Gasoline	1999	0.1435	0.0578
Gasoline	2000	0.1092	0.0493
Gasoline	2001	0.1235	0.0528
Gasoline	2002	0.1307	0.0546
Gasoline	2003	0.124	0.0533
Gasoline	2004	0.0285	0.0341
Gasoline	2005-present	0.0177	0.0326
Diesel	1960-present	0.0048	0.0051
Ethanol	All	0.175	0.197

Table B.11: Electrical grid make-up of the various EPA subregions [adapted from (USEPA, 2010)].

	Electrical Grid Composition									
EPA Subregion	Coal	Oil	Gas	Other Fossils	Biomass	Hydroelectric	Nuclear	Wind	Solar PV	Geothermal
AKGD	11.8%	10.4%	70.1%	0.0%	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%
AKMS	0.0%	32.2%	3.4%	0.0%	0.7%	63.6%	0.0%	0.1%	0.0%	0.0%
AZNM	40.2%	0.1%	36.2%	0.0%	0.2%	5.9%	14.8%	0.4%	0.0%	2.1%
CAMX	7.6%	1.0%	52.5%	0.9%	2.4%	12.1%	16.2%	2.5%	0.3%	4.4%
ERCT	34.4%	0.4%	49.5%	0.9%	0.1%	0.3%	12.0%	2.4%	0.0%	0.0%
FRCC	26.9%	9.2%	47.3%	0.6%	1.7%	0.0%	13.4%	0.0%	0.0%	0.0%
HIMS	1.9%	76.9%	0.0%	0.0%	3.6%	2.9%	0.0%	7.4%	0.0%	7.2%
HIOA	18.2%	77.4%	0.0%	2.5%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%
MROE	66.6%	3.2%	7.9%	0.1%	3.4%	3.0%	15.6%	0.1%	0.0%	0.0%
MROW	71.0%	0.5%	5.0%	0.2%	1.0%	3.5%	15.4%	3.4%	0.0%	0.0%
NEWE	15.1%	4.2%	40.8%	1.5%	5.8%	4.5%	27.9%	0.1%	0.0%	0.0%
NWPP	32.0%	0.2%	12.8%	0.3%	1.1%	48.4%	3.0%	1.9%	0.0%	0.3%
NYCW	0.0%	5.0%	56.3%	0.4%	0.5%	0.0%	37.8%	0.0%	0.0%	0.0%
NYLI	0.0%	31.4%	61.3%	3.4%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%
NYUP	23.1%	2.2%	17.9%	0.4%	1.3%	26.4%	27.8%	0.9%	0.0%	0.0%
RFCE	42.2%	1.1%	13.1%	1.1%	1.2%	0.9%	40.3%	0.2%	0.0%	0.0%
RFCM	69.8%	0.7%	12.2%	0.6%	1.8%	0.0%	14.8%	0.0%	0.0%	0.0%
RFCW	72.9%	0.3%	2.9%	0.6%	0.3%	0.6%	22.3%	0.1%	0.0%	0.0%
RMPA	71.3%	0.1%	23.6%	0.0%	0.0%	2.9%	0.0%	2.0%	0.0%	0.0%
SPNO	74.9%	0.3%	8.1%	0.0%	0.0%	0.1%	14.8%	1.6%	0.0%	0.0%
SPSO	56.4%	0.2%	34.6%	0.3%	1.6%	4.4%	0.0%	2.4%	0.0%	0.0%
SRMV	23.0%	1.6%	44.7%	1.3%	2.2%	1.4%	25.5%	0.0%	0.0%	0.0%

Table B.11 (continued): Electrical grid make-up of the various EPA subregions [adapted from (USEPA, 2010)].

	Electrical Grid Composition									
EPA Subregion	Coal	Oil	Gas	Other Fossils	Biomass	Hydroelectric	Nuclear	Wind	Solar PV	Geothermal
SRMW	80.8%	0.1%	4.4%	0.0%	0.1%	1.3%	13.4%	0.0%	0.0%	0.0%
SRSO	63.5%	0.3%	15.1%	0.1%	2.9%	1.4%	16.6%	0.0%	0.0%	0.0%
SRTV	66.1%	1.2%	7.2%	0.0%	0.9%	3.7%	20.8%	0.0%	0.0%	0.0%
SRVC	51.1%	0.9%	6.7%	0.2%	2.0%	0.7%	38.4%	0.0%	0.0%	0.0%

Appendix C

Clemson University Energy Use Assessment Survey

WATER TREATMENT ENERGY ASSESSMENT SURVEY

The data gathered in this survey will provide a much needed overview of the power demands of a water treatment plant. The compiled data will allow for electrical use comparisons between common treatment options as well as various plant sizes. The data will also be utilized to further study the sustainable operation of water treatment plants. Published literature has illustrated that the most important input to a water treatment plant when considering its environmental impact is energy use. Given this energy use and the source of electricity production, the greenhouse gas (GHG) emissions associated with a plant can be calculated. Further analysis will be undertaken to understand how various water treatment techniques and different energy grids affect the environmental impact of treating water. Future scenarios including a changing energy grid and possible carbon legislation will also be studied using the compiled energy data as a baseline. There is space provided in the energy use information section for you to provide any additional thoughts and uncharacteristic details about your process. Your participation in this survey is sincerely appreciated.

****All data obtained from the survey will be kept anonymous****

Contact Information

Please enter your contact information:

Name of Facility: ____

PWS ID: ____

Address: ____

Phone: ____

E-Mail: ____

Name of Individual Completing the Survey:
____

Age of WTP: ____

Estimated Age of Distribution System:
____

WTP Website: ____

Basic WTP Information

1.) Size of your WTP? (MGD)

____

2.) Approximate number of people serviced?

____

3.) Please list your daily production (MGD)

	Average	**Maximum**	**Design**
Ground	___	___	___
Surface & GWUDI	___	___	___
Purchased	___	___	___

Please indicate each treatment process / chemical that is used in your water system below

4.) Disinfection
[ ] Cl gas [ ] Hypo [ ] Ozone [ ] UV [ ] Other

If you selected other, please explain

____

Clarification
[ ] Gravity [ ] Up-flow [ ] DAF

Residuals Management
[ ] None [ ] Non-Mechanical [ ] Mechanical

Number of processes

Other/Miscellaneous

[ ] Aeration with Blowers [ ] Softening/Ion Exchange [ ] Reservoir Aeration

[ ] Rapid Mix [ ] Flocculation [ ] Backwash System

Is there any other treatment processes or chemicals used in your system that was not listed above? Please explain

____

____

____

____

Objectives & Preliminary Energy Information

5.) Quantity of chemicals used:

	Quantity	**Units**
Chlorine	___	___
Ammonia	___	___
Hypochlorite	___	___
Ozone	___	___
Potassium Permanganate	___	___
Fluoride	___	___
Lime	___	___
Soda Ash	___	___
Coagulent	___	___
Coagulent	___	___
Coagulent	___	___
Other	___	___
Other	___	___
Other	___	___

What Coagulant(s)?

____

If you selected other, please explain:

6.) What are your distribution/treatment objectives
[ ] Disinfection [ ] Particulate [ ] Metals [ ] Taste/Odor [ ] Hardness [ ] TOC

[ ] Contaminate(Organic/Inorganic/Radionuclide) [ ] Other

If you selected other, please explain

____

7.) How many engine driven pumps do you use?

____

8.) How many Variable Frequency Drive (VFDs) pump controllers do you have?

____

9.) Does your energy provider offer renewable energy?
( ) Yes ( ) No

If yes, to what extent do you participate in the program?

____

____

____

____

10.) Have you ever participated in an energy audit?
( ) Yes ( ) No

If yes, what agency/consulting firm conducted the survey?

____

11.) Have you had any upgrades (i.e. equipment, software, employee programs/training) in the last 5 years towards conserving energy?
( ) Yes ( ) No

Please explain

____

____

____

____

12.) How much of a priority is energy conservation for the plant (1 being no priority, 10 being the most priority)

( ) 1 ( ) 2 ( ) 3 ( ) 4 ( ) 5 ( ) 6 ( ) 7 ( ) 8 ( ) 9 ( ) 10

Energy Use Information

The following section includes an energy use table for the years of 2008 and 2009 to be filled in. We ask that you include your monthly energy use along with your monthly flow (if available) in the units of your choosing. Below is space for you to describe any special considerations that you plant may operate under or any other additional comments you feel may be of interest to the survey. Some suggested areas of comment are: what if any seasonal variation does your plant deal with, does your plant operate as a wholesaler or a distributor, and is your energy supplied through bulk pricing or unit pricing?

____

____

____

____

13.) Does your energy consumption include raw water pumping?

( ) Yes ( ) No

If Yes, how far is your water pumped?

____

Does your energy consumption include distribution?

( ) Yes ( ) No

If Yes, how far is your distribution reach?

____

14.) What type of energy do you use?

[ ] Electricity [ ] Natural Gas [ ] Fuel Oil [ ] Propane [ ] Other

If you selected other, explain:

____

____

____

____

How much of the selected energies do you use?

ELECTRICAL USE SUMMARY - 2008 & 2009
*** Flow units to be in MGD**
*** All electrical units required for Electric Use is kWh and Demand is kW**

	Flow	**Raw Water Supply (Pumping) - Electric Use**	**Raw Water Supply (Pumping) - Demand**	**Treatment Facility - Electric Use**	**Treatment Facility - Demand**	**Distribution System - Electric Use**	**Distribution System - Demand**
January-08	___	___	___	___	___	___	___
February-08	___	___	___	___	___	___	___
March-08	___	___	___	___	___	___	___
April-08	___	___	___	___	___	___	___
May-08	___	___	___	___	___	___	___
June-08	___	___	___	___	___	___	___
July-08	___	___	___	___	___	___	___
August-08	___	___	___	___	___	___	___
September-08	___	___	___	___	___	___	___
October-08	___	___	___	___	___	___	___
November-08	___	___	___	___	___	___	___
December-08	___	___	___	___	___	___	___
January-09	___	___	___	___	___	___	___
February-09	___	___	___	___	___	___	___
March-09	___	___	___	___	___	___	___
April-09	___	___	___	___	___	___	___
May-09	___	___	___	___	___	___	___
June-09	___	___	___	___	___	___	___

July-09	___	___	___	___	___	___	___
August-09	___	___	___	___	___	___	___
September-09	___	___	___	___	___	___	___
October-09	___	___	___	___	___	___	___
November-09	___	___	___	___	___	___	___
December-09	___	___	___	___	___	___	___

Thank You!

Thank you for taking our survey. Your response is extremely appreciated and will be used towards beneficial research at Clemson University to allow water treatment utilities to increase their sustainability to the environment. If you have any questions or comments on the survey, email Clemson.WTPSurvey@gmail.com.

Appendix D

Supplemental Information for Chapter 5

Table D.1: Survey data set used to form the raw water collection energy prediction equation.

Plant ID	Average Ground Water Flow	Average Surface Water Flow	Average Purchased Water Flow	Total Average Flow	Average Well Depth	Source Water Pumping HP	Collection Energy Use
	kGD	kGD	kGD	kGD	ft	hp	kWh/yr
AL001	0	1920	0	1920	0	75	280640
AL003	3800	0	0	3800	260	1430	2157200
AL004	0	5370	0	5370	0	1200	1054200
AL006	0	3000	0	3000	0	400	1489320
AR002	57850	0	0	57850		10550	17080000
AR003	1300	0	0	1300	500	405	721344
AZ001	10000	0	0	10000	650	2115	4767795
AZ002	980	0	0	980	700	300	310280
CA007	3500	0	2500	6000	100	285	2700000
CA010	1700	0	0	1700		450	159400
CA011	2650	0	3790	6440	1117	375	29796
CA015	3000	0	0	3000	340	300	750920
CA016	8800	0	9600	18400	580	3050	6994464
CA017	3300	0	3700	7000	585	350	1407869
CA018	28510	0	22680	51190	1000	7700	15351439
CA020	0	25000	3000	28000	0	3550	1092341
CA021	8960	0	0	8960	871	2750	9393697
CA022	30800	7600	36900	75300	783	10000	23782000
CA023	4200	0	18800	23000		0	1044900
CA026	3000	1000	0	4000	500	550	1597265
CA028	17600	0	0	17600	566	3980	15090982
CA030	460	6540	205000	212000	440	600	5977300
CA031	4600	12700	6900	24200	800	190	4501000
CA035	0	0	4000	4000	500	490	934277
CA040	340	10830	0	11170	200	1200	4069114

Table D.1 (continued): Survey data set used to form the raw water collection energy prediction equation.

Plant ID	Average Ground Water Flow	Average Surface Water Flow	Average Purchased Water Flow	Total Average Flow	Average Well Depth	Source Water Pumping HP	Collection Energy Use
	kGD	kGD	kGD	kGD	ft	hp	kWh/yr
CA041	13910	28340	0	42250	200	4740	10988819
CA045	1000	0	0	1000	300	270	8
CA046	3600	2100	7500	13200	420	675	35700
CT002	1750	0	0	1750	94	330	968292
IA007	5810	0	0	5810	110	745	1700740
IL002	0	568000	0	568000	0	11000	39105499
IL003	0	338600	0	338600	0	6400	23310611
IL005	10800	8200	0	19000	1350	5350	15149532
IL006	6000	0	0	6000	110	2000	1942456
IL011	0	22000	0	22000	0	725	9400400
IL012	500	0	2160	2660	1500	250	300000
KS001	0	2190	0	2190	40	190	381440
KS002	0	4340	0	4340	70	825	412399
LA003	50300	0	0	50300	1800	9500	31561400
LA007	1200	0	0	1200	2000	555	1204524
MD001	500	2200	0	2700	200	180	81865
MD002	4730	0	0	4730	375	60	152979
MN001	9900	0	2700	12600	450	975	3437660
MN002	2100	0	0	2100	400	475	975000
MO002	29000	0	0	29000	108	2560	3885039
MO003	2650	0	0	2650	130	330	2456575
MO005	1870	10670	0	12540	1516	1450	7569260
MO007	2860	28380	0	31240	1200	12550	12155143
NC005	0	43200	0	43200	0	8835	28765720
NC006	0	2990	0	2990	0	600	1225328
NC009	2640	0	0	2640	196	580	956434
NC012	6450	0	0	6450	593	1795	5431621
NC013	0	9770	0	9770	0	600	7542773
NE001	27900	10800	0	38700	84	5095	9041046
OH004	18700	0	0	18700	84	950	3780667
OH007	0	2600	0	2600	0	300	514299

Table D.1 (continued): Survey data set used to form the raw water collection energy prediction equation.

Plant ID	Average Ground Water Flow kGD	Average Surface Water Flow kGD	Average Purchased Water Flow kGD	Total Average Flow kGD	Average Well Depth ft	Source Water Pumping HP hp	Production Energy Use kWh/yr
OK003	0	3900	0	3900	0	0	821100
OR003	2900	99200	0	102100	383.4	6940	5495179
PA001	700	0	0	700	400	195	583404
PA003	4890	450	0	5340	250	2750	2400000
PA004	0	2730	0	2730	0	50	1586560
PA006	0	3250	0	3250	350	0	22499
PA007	0	36600	0	36600	0	1050	31823059
PA008	0	42100	0	42100	0	7600	51559017
PA010	0	6500	20	6520	0	600	7692307
PA011	0	4080	0	4080	0	150	528290
PA012	0	27800	0	27800	0	2300	16495421
SD001	6000	6000	0	12000	1500	2330	6741530
TN001	0	1680	29900	31580	0	100	482800
TX003	0	4080	0	4080	0	600	1453092
UT002	4500	0	0	4500	500	1395	2457745
UT003	12220	33890	37800	83910	385	3805	6605123
VA005	0	142000	0	142000	0	14000	150000000
VT003	0	1580	0	1580	0	100	745920
WA002	4010	3650	0	7660	361.13	430	2451546
WA003	10100	0	0	10100	375	4950	10161720
WA005	5300	0	0	5300	337	1865	4223996
WA006	7000	0	0	7000	250	2327	5067505
WA007	1530	0	0	1530	234	700	859300
WI002	0	4000	0	4000	0	1100	2152320
WI003	2120	0	0	2120	65	597.5	1117100
WY001	0	2700	0	2700	0	0	56080
NY006	1000	0	0	1000			260800
NY009	0	2500	0	2500	0		2836
NY016	2500	0	0	2500			2343652
NY024	120	0	0	120			98227
NY047	500	0	0	500			32664

Table D.1 (continued): Survey data set used to form the raw water collection energy prediction equation.

Plant ID	Average Ground Water Flow kGD	Average Surface Water Flow kGD	Average Purchased Water Flow kGD	Total Average Flow kGD	Average Well Depth ft	Source Water Pumping HP hp	Production Energy Use kWh/yr
NY055	117	0	0	117			90705
NY069	0	5000	0	5000	0		41441
NY082	400	0	0	400			107507
NY092	0	17500	24000	41500	0		69552
NY095	800	800	0	1600			536624
NY097	150	0	0	150			597841
NY115	17000	0	0	17000			2678
NY133	0	309	0	309	0		187200
NY153	200	1300	0	1500			531920
NY168	70	0	0	70			33177
NY170	190	0	0	190			135569
CU03	0	80000	0	80000	0		3917263
CU04	26400	16000	0	42400			4895400
CU06	11900	0	0	11900	280	785	3641764
CU08	0	500	47	547	0	150	347040
CU10	0	7000	0	7000	0		579000
CU13	0	28000	0	28000	0		1714895
CU18	0	120000	0	120000	0	11000	20910035
CU19	17000	0	0	17000	123	1500	3367443
CU24	0	19500	0	19500	0	675	957400
CU25	0	13000	0	13000	0		3445422
CU31	2900	12000	0	14900	95	1900	3571680
CU32	0	40000	0	40000	0		17477350
CU34	0	7900	0	7900	0	2650	2629900
CU35	0	19500	0	19500	0		2064191

Table D.2: Part 1 of the survey data set used to form the treatment process energy prediction equation, including the various flow rates and electricity use information.

Plant ID	Average Ground Water Flow kGD	Average Surface Water Flow kGD	Average Purchased Water Flow kGD	Total Average Flow kGD	Treatment Energy Use kWh/yr
AL001	0	1920	0	1920	253920
AL003	3800	0	0	3800	124650
AL006	0	3000	0	3000	810920
AR002	57850	0	0	57850	7820000
AR003	1300	0	0	1300	600538
CA018	28510	0	22680	51190	8723340
CA020	0	25000	3000	28000	1468240
CA030	460	6540	205000	212000	962166
CA031	4600	12700	6900	24200	1814000
CA040	340	10830	0	11170	1434240
CA041	13910	28340	0	42250	539360
IA007	5810	0	0	5810	656040
IL006	6000	0	0	6000	1452024
KS001	0	2190	0	2190	888000
KS002	0	4340	0	4340	278976
MD001	500	2200	0	2700	2404200
MD002	4730	0	0	4730	316413
MN001	9900	0	2700	12600	971242
MO002	29000	0	0	29000	1173320
MO005	1870	10670	0	12540	169599
MO007	2860	28380	0	31240	21274887
NC006	0	2990	0	2990	872480
NC009	2640	0	0	2640	170240
NC012	6450	0	0	6450	1782420
NE001	27900	10800	0	38700	14326997
OH007	0	2600	0	2600	1610400
PA003	4890	450	0	5340	1500000
PA006	0	3250	0	3250	281074
PA010	0	6500	20	6520	1923076
PA011	0	4080	0	4080	176096
TN001	0	1680	29900	31580	1036800

Table D.2 (continued): Part 1 of the survey data set used to form the treatment process energy prediction equation, including the various flow rates and electricity use information.

Plant ID	Average Ground Water Flow kGD	Average Surface Water Flow kGD	Average Purchased Water Flow kGD	Total Average Flow kGD	Treatment Energy Use kWh/yr
TX003	0	4080	0	4080	1724448
UT003	12220	33890	37800	83910	1769992
WI002	0	4000	0	4000	1177440
WI003	2120	0	0	2120	371725
WY001	0	2700	0	2700	569400
NY069	0	5000	0	5000	211360
NY095	800	800	0	1600	85658
NY115	17000	0	0	17000	1057685
NY133	0	309	0	309	69960
NY153	200	1300	0	1500	169854
CU04	26400	16000	0	42400	4895400
CU06	11900	0	0	11900	8282760
CU08	0	500	47	547	287350
CU10	0	7000	0	7000	3205367
CU13	0	28000	0	28000	12779191
CU18	0	120000	0	120000	21506910
CU19	17000	0	0	17000	2722638
CU24	0	19500	0	19500	2374500
CU25	0	13000	0	13000	1470022
CU31	2900	12000	0	14900	7392800
CU32	0	40000	0	40000	6257952
CU34	0	7900	0	7900	882463
CU35	0	19500	0	19500	14639786

Table D.3: Part 2 of the survey data set used to form the treatment process energy prediction equation, including the treatment processes used at the water utility.

Plant ID	Conventional	Direct Filtration	Slow Sand Filtration	Aeration	Pressure Filtration	Softening	DAF	Ozone	UV	Membrane Filtration	Nanofiltration	RO
AL001	1	0	0	0	0	0	0	0	0	0	0	0
AL003	1	0	0	1	0	0	0	0	0	0	0	0
AL006	1	0	0	0	0	0	0	0	0	0	0	0
AR002	1	0	0	0	0	0	0	0	0	0	0	0
AR003	0	1	0	1	1	0	0	0	0	0	0	0
CA018	0	0	0	0	0	0	0	0	0	0	1	0
CA020	1	0	0	0	0	0	0	0	0	0	0	0
CA030	1	0	0	0	0	0	0	0	0	0	0	0
CA031	1	0	0	0	0	0	0	0	0	0	0	1
CA040	1	0	0	1	1	0	0	0	0	0	0	0
CA041	0	1	0	0	0	0	0	0	0	0	0	0
IA007	1	0	0	0	0	1	0	0	0	0	0	0
IL006	0	0	1	0	0	0	0	0	0	0	0	0
KS001	1	0	0	0	0	1	0	0	0	0	0	0
KS002	1	0	0	0	0	1	0	0	0	0	0	0
MD001	1	0	0	0	1	0	0	0	0	0	0	0
MD002	1	0	0	1	1	0	0	0	0	0	0	0
MN001	1	0	0	0	0	1	0	0	0	0	0	0
MO002	1	0	0	0	0	1	0	0	0	0	0	0
MO005	1	0	0	0	0	0	0	0	0	0	0	0

Table D.3 (continued): Part 2 of the survey data set used to form the treatment process energy prediction equation, including the treatment processes used at the water utility.

Plant ID	Conven-tional	Direct Filtration	Slow Sand Filtra-tion	Aeration	Pressure Filtration	Soft-ening	DAF	Oz-one	UV	Membrane Filtration	Nanofiltra-tion	RO
MO007	1	0	0	0	0	0	0	0	0	0	0	0
NC006	1	0	0	0	0	0	0	0	0	0	0	0
NC009	1	0	0	1	0	0	0	0	0	0	0	0
NC012	0	1	0	1	1	1	0	0	0	0	0	0
NE001	0	1	0	0	0	0	0	1	0	0	0	0
OH007	1	0	0	0	0	1	0	0	0	0	0	0
PA003	1	0	0	0	0	0	0	0	0	0	0	0
PA006	1	0	0	0	0	0	0	1	0	0	0	0
PA010	1	0	0	0	0	0	0	0	0	0	0	0
PA011	1	0	0	0	0	0	0	0	0	0	0	0
TN001	0	0	1	0	0	0	0	0	0	0	0	0
TX003	1	0	0	0	0	0	0	0	0	0	0	0
UT003	1	0	0	0	0	0	0	0	0	0	0	0
WI002	0	1	0	0	0	0	0	0	1	0	0	0
WI003	0	0	1	1	0	0	0	0	0	0	0	0
WY001	1	0	0	0	0	0	0	0	0	0	0	0
NY069	0	1	0	0	0	0	0	0	0	0	0	0
NY095	1	0	0	1	0	0	0	0	0	0	0	0
NY115	1	0	0	0	0	0	0	0	0	0	0	0
NY133	0	1	0	0	0	0	0	0	0	0	0	0

Table D.3 (continued): Part 2 of the survey data set used to form the treatment process energy prediction equation, including the treatment processes used at the water utility.

Plant ID	Conven-tional	Direct Filtration	Slow Sand Filtra-tion	Aeration	Pressure Filtration	Soft-ening	DAF	Oz-one	UV	Membrane Filtration	Nanofiltra-tion	RO
NY153	1	0	0	1	0	0	0	0	0	0	0	0
CU04	1	0	0	0	0	0	0	1	0	0	0	0
CU06	1	0	0	0	0	1	0	1	0	0	0	0
CU08	0	1	0	0	0	0	0	0	0	0	0	0
CU10	1	0	0	1	0	1	0	0	0	0	0	0
CU13	1	0	0	0	0	0	0	0	0	0	0	0
CU18	1	0	0	0	0	0	0	0	0	0	0	0
CU19	0	1	0	0	0	1	0	0	0	0	0	0
CU24	1	0	0	0	0	0	0	0	0	0	0	0
CU25	0	0	0	0	0	0	0	0	0	1	0	0
CU31	1	0	0	0	0	1	0	1	0	0	0	0
CU32	1	0	0	0	0	0	0	0	0	0	0	0
CU34	1	0	0	0	0	0	0	0	0	0	0	0
CU35	1	0	0	0	0	0	0	0	0	0	0	0

Table D.4: Survey data set used to form the finished water distribution energy prediction equation.

Plant ID	Total Average Flow MGD	Length of Water Mains mi	Distribution Pumping HP hp	Average Distribution Pressure psi	Elevation Difference ft	Distribution Energy Use kWh/yr
AL001	1.92	101	320	61	140	906054
AL003	3.8	210	675	100	266	2450293
AL004	5.37	216	100	60	125	200600
AL006	3	200	20	60	45	13391
AR002	57.85	2200	8000	100	460	8776000
AR003	1.3	275	300	70	260	44748
AZ001	10	300	2702.5	55	900	1662389
AZ002	0.98	30	230	65	100	566720
CA002	5.5	110	2285	0	692	983560
CA004	7.75	70	1000	80	0	586000
CA007	6	88	500	120	1800	3200000
CA010	1.7	12.1	95	58	0	40440
CA012	3.68	130	405	80	250	1350869
CA014	2.9	48	225	58	200	638570
CA015	3	180	2325	62	480	188602
CA016	18.4	350	4100	74	78	57180
CA017	7	100	295	70	183	1259166
CA018	51.19	1078	4800	60	1462	15602396
CA019	6	100	220	50	360	142140
CA020	28	400	680	50	490	111941
CA022	75.3	800	18000	90	1545	23434000
CA029	16.9	324	3160	125	1300	2794369
CA030	212	3317	6900	60	870	23909199
CA031	24.2	390	2045	60	495	2242000
CA033	5.5	160	790	50	610	971359
CA035	4	100	1165	90	960	1265101
CA036	11.4	250	100	75	550	111211
CA037	16	309.19	2810	122	1396	1549247
CA038	5	52	0	85	51	74455
CA039	15	269	2900	80	800	4968982
CA040	11.17	262	950	85	1014	1443194

Table D.4 (continued): Survey data set used to form the finished water distribution energy prediction equation.

Plant ID	Total Average Flow MGD	Length of Water Mains mi	Distribution Pumping HP hp	Average Distribution Pressure psi	Elevation Difference ft	Distribution Energy Use kWh/yr
CA041	42.25	467	2005	75	0	1521450
CA042	4.54	89.24	330	58	-5	15307
CO003	17	450	3500	65	307	1050000
CO007	4.65	144	220	75	628	584200
CO009	21.8	524	600	81	377	794769
CO010	23.6	538	10300	70	500	14628500
CT002	1.75	75	30	80	320	111686
FL003	66.98	2000	3275	50	80	9811701
GA001	28.8	1100	2150	65	0	7342000
IA002	4.26	150	150	50	195.06	818240
IA007	5.81	220	16000	75	180	2258320
IL002	568	4240	22764	35	85	118147638
IL003	338.6	4240	22764	35	85	118147638
IL005	19	600	5150	65	80	5570400
IL006	6	210	1100	55	4	5907
IL010	3.81	200	350	60	46	293760
IL012	2.66	170	250	55	50	100000
KS002	4.34	180	1375	90	330	521564
LA003	50.3	1490.62	1055	65	37	240940
LA007	1.2	260	40	60	80	81600
MD001	2.7	119	800	55	432	133582
MD002	4.73	125	500	44	10	6963
MI004	13.2	221.5	665	75	127	569109
MI006	8	201	200	52	36	109020
MI007	2	180	1005	62	100	1139906
MN001	12.6	488	2455	68	270	3194091
MO002	29	722	1035	85	320	25637367
MO003	2.65	87	725	60	140	683136
MO005	12.54	430	545	65	276	1622478
MO007	31.24	1126	1120	60	277	551608
MT001	11.23	290	6600	73	370	1097700

Table D.4 (continued): Survey data set used to form the finished water distribution energy prediction equation.

Plant ID	Total Average Flow MGD	Length of Water Mains mi	Distribution Pumping HP hp	Average Distribution Pressure psi	Elevation Difference ft	Distribution Energy Use kWh/yr
NC004	0.7	150	50	50	338	1851246
NC005	43.2	1900	15630	80	250	8743330
NC007	1.85	350	850	75	390	369983
NC009	2.64	172	275	78	45	108250
NC010	2.59	120	625	68	86	248255578
NC012	6.45	910	1925	70	38	149843
NE001	38.7	1131.9	9850	65	310	21205900
NH001	1.99	116	284	60	390	195505
OH007	2.6	108	385	65	109	574296
OK001	98.23	2325.2	1625	70	310	2021846
OR002	5	180	1585	65	660	813640
OR003	102.1	1957	14668	76	1263	16860771
PA003	5.34	215	600	55	240	370000
PA004	2.73	68	420	72	455	368462
PA006	3.25	200	20	75	544	24183
PA010	6.52	320	500	100	800	2307692
PA011	4.08	106	625	80	553	1721254
PA012	27.8	685	2025	74	672	6969549
PA014	0.75	61	200	50	170	1044824
SD001	12	359	800	60	588	2393775
TN001	31.58	1000	152.5	85	582	151.54
TX008	130.5	3036	0	72	705	28536936
UT003	83.91	1376.21	15575	110	1562	10899986
VA004	7.05	320	1275	85	260	1182629
VA005	142	3154	3000	80	340	50000000
VT003	1.58	76	0	150	610	21000
WA002	7.66	300	994	50	650	1397240
WA003	10.1	600	700	55	0	1936510
WA005	5.3	267	770	45	650	1346680
WI001	131	1960	44230	73	231.2	53183166
WI003	2.12	135	875	70	150	535815

Table D.4 (continued): Survey data set used to form the finished water distribution energy prediction equation.

Plant ID	Total Average Flow	Length of Water Mains	Distribution Pumping HP	Average Distribution Pressure	Elevation Difference	Distribution Energy Use
	MGD	mi	hp	psi	ft	kWh/yr
WY001	2.7	0	0	0	1431	29688
NY009	2.5	0		0		76130
NY011	1.7	50		70		188
NY025	0.21	9		40		19000
NY036	1.75	140		100		489300
NY065	2.9	76		100		52992
NY069	5	80		75		1005696
NY089	0.5	25.5		70		17591
NY102	1.7	500		112		648000
NY111	0.7	13		55		12612
NY115	17	155		100		2144441
NY116	0.7	13		55.6		12612
NY133	0.309	19		82		35616
NY151	1.225	40		70		54677
NY153	1.5	72		75		95640
CU06	11.9	9	2300	65		639267
CU07	4.2				65	985575
CU10	7					273800
CU13	28	15				1275362
CU18	120	3000	49000	45	550	91646984
CU25	13				200	5348823
CU27	4	5	1450	50	100	927980
CU31	14.9	10	2875	55	637	923706
CU34	7.9		1650	83	143	2954333
CU35	19.5					4707851

Appendix E

SAS Program Codes for Energy Prediction Equations

E.1 SAS Program Code for Raw Water Collection Energy Prediction Equation for Utilities without Purchased Water Flow

```
PROC IMPORT OUT= WORK.ONE
        DATAFILE= "C:\Johnston\RawWaterCollectionSAS_NoPurchased.xls"
        DBMS=XLS REPLACE;
   GETNAMES=YES;
RUN;
PROC PRINT;
RUN;
data one;SET ONE;
COLLECTION=X7;
COLLECTION2=COLLECTION**2;LCOLLECTION=LOG10(COLLECTION);SCOL
LECTION=SQRT(COLLECTION);
FLOW=X4;FLOW2=FLOW**2;SFLOW=SQRT(FLOW);LFLOW=LOG10(X4);
X1_2=X1**2;LX1=LOG10(X1+1);SX1=SQRT(X1);
X2_2=X2**2;LX2=LOG10(X2+1);SX2=SQRT(X2);
X3_2=X3**2;LX3=LOG10(X3+1);SX3=SQRT(X3);
X5_2=X5**2;LX5=LOG10(X5+1);SX5=SQRT(X5);
X6_2=X6**2;LX6=LOG10(X6+1);SX6=SQRT(X6);
/*
LFLOW=LFLOW-3.98335;LX6=LX6-3.04619;
*/
LFLOWLX6=LFLOW*LX6;
OBS=_N_;
label x1='Average Groundwater Flow'
    x2='Average Surface Water Flow'
         x3='Average Purchased Water Flow'
         x4='Total Average Flow'
         x5='Average Well Depth'
         x6='Source Water Pumping HP'
         x7='Collection Energy Use'
IF COLLECTION=0 THEN DELETE;
DATA ONE;
SET ONE;
OBS=_N_;
/*
```

```
PROC GLMSELECT;
*partition fraction(TEST=.20 validate=0.20);
MODEL LCOLLECTION=X1|X2|X3|X4|X5|X6|
        LFLOW|FLOW2|SFLOW|
                X1_2|LX1|SX1|
                X2_2|LX2|SX2|
                X3_2|LX3|SX3|
                X5_2|LX5|SX5|
                X6_2|LX6|SX6 @2 / SELECTION=LASSO;
RUN;QUIT;
*/
ODS GRAPHICS ON;
PROC REG PLOTS=(DIAGNOSTICS(STATS=NONE) DFFITS DFBETAS
PARTIAL);;
MODEL LCOLLECTION=LFLOW LX6  / VIF INFLUENCE R PARTIAL SPEC;
ID FLOW X6 ;
OUTPUT OUT=SUMMARY STUDENT=RESIDUAL P=YHAT;
PROC UNIVARIATE NORMAL PLOT;
 VAR RESIDUAL;
run;
ODS GRAPHICS OFF;
quit;
```

E.2 SAS Program Code for Raw Water Collection Energy Prediction Equation for Utilities with Purchased Water Flow

```
PROC IMPORT OUT= WORK.ONE
        DATAFILE= "C:\Johnston\RawWaterCollectionSAS_OnlyPurchased.xls"
        DBMS=XLS REPLACE;
    GETNAMES=YES;
RUN;
PROC PRINT;
RUN;
data one;SET ONE;
COLLECTION=X7;
COLLECTION2=COLLECTION**2;LCOLLECTION=LOG10(COLLECTION);SCOL
LECTION=SQRT(COLLECTION);
FLOW=X4;FLOW2=FLOW**2;SFLOW=SQRT(FLOW);LFLOW=LOG10(X4);
X1_2=X1**2;LX1=LOG10(X1+1);SX1=SQRT(X1);
X2_2=X2**2;LX2=LOG10(X2+1);SX2=SQRT(X2);
X3_2=X3**2;LX3=LOG10(X3+1);SX3=SQRT(X3);
X5_2=X5**2;LX5=LOG10(X5+1);SX5=SQRT(X5);
X6_2=X6**2;LX6=LOG10(X6+1);SX6=SQRT(X6);
/*
LFLOW=LFLOW-3.98335;LX6=LX6-3.04619;
*/
LFLOWLX6=LFLOW*LX6;
OBS=_N_;
label x1='Average Groundwater Flow'
     x2='Average Surface Water Flow'
          x3='Average Purchased Water Flow'
          x4='Total Average Flow'
          x5='Average Well Depth'
          x6='Source Water Pumping HP'
          x7='Collection Energy Use'
IF COLLECTION=0 THEN DELETE;
DATA ONE;
SET ONE;
OBS=_N_;
/*
PROC GLMSELECT;
*partition fraction(TEST=.20 validate=0.20);
MODEL LCOLLECTION=X1|X2|X3|X4|X5|X6|
      LFLOW|FLOW2|SFLOW|
                X1_2|LX1|SX1|
                X2_2|LX2|SX2|
```

```
          X3_2|LX3|SX3|
          X5_2|LX5|SX5|
          X6_2|LX6|SX6 @2 / SELECTION=LASSO;
RUN;QUIT;
*/
ODS GRAPHICS ON;
PROC REG PLOTS=(DIAGNOSTICS(STATS=NONE) DFFITS DFBETAS
PARTIAL);;
MODEL LCOLLECTION=LFLOW LX6 LX3  / VIF INFLUENCE R PARTIAL SPEC;
ID FLOW X3 X6 ;
OUTPUT OUT=SUMMARY STUDENT=RESIDUAL P=YHAT;
PROC UNIVARIATE NORMAL PLOT;
 VAR RESIDUAL;
run;
ODS GRAPHICS OFF;
quit;
```

E.3 SAS Program Code for Finished Water Distribution Energy Prediction Equation

```
PROC IMPORT OUT= WORK.ONE
        DATAFILE= "C:\Johnston\DistributionDataSAS.xls"
        DBMS=XLS REPLACE;
   GETNAMES=YES;
RUN;
PROC PRINT;
RUN;
data one;SET ONE;
DISTRIBUTION=X6;
DISTRIBUTION2=DISTRIBUTION**2;LDISTRIBUTION=LOG10(DISTRIBUTION)
;SDISTRIBUTION=SQRT(DISTRIBUTION);
X1_2=X1**2;SX1=SQRT(X1);LX1=LOG10(X1);
X3_2=X3**2;LX3=LOG10(X3+1);SX3=SQRT(X3);
X2_2=X2**2;LX2=LOG10(X2+1);SX2=SQRT(X2);
X5_2=X5**2;LX5=LOG10(X5+1);SX5=SQRT(X5);
X4_2=X4**2;LX4=LOG10(X4+1);SX4=SQRT(X4);
/*
LX1=LX1-.96324;LX2=LX2-2.43724;LX3=LX3-3.00553;LX4=LX4-
1.81854;LX5=LX5-2.34092;
*/
LX1LX3=LX1*LX3;
LX3LX5=LX3*LX5;
LX3LX2=LX3*LX2;
LX3LX4=LX3*LX4;
OBS=_N_;
label x1='Total Average Flow'
    x2='Length of Water Mains'
        x3='Distribution Pumping HP'
        x4='Average Distribution Pressure'
        x5='Elevation Change'
        x6='Distribution Energy Use'
IF DISTRIBUTION=0 THEN DELETE;
IF OBS=16 THEN DELETE;
IF OBS=29 THEN DELETE;
IF OBS=33 THEN DELETE;
IF OBS=43 THEN DELETE;
IF OBS=44 THEN DELETE;
IF OBS=46 THEN DELETE;
IF OBS=53 THEN DELETE;
IF OBS=63 THEN DELETE;
```

```
IF OBS=67 THEN DELETE;
IF OBS=83 THEN DELETE;
IF OBS=84 THEN DELETE;
IF OBS=88 THEN DELETE;
IF OBS=94 THEN DELETE;
DATA ONE;
SET ONE;
OBS=_N_;
/*
PROC GLMSELECT;
*partition fraction(TEST=.20 validate=0.20);
MODEL LDISTRIBUTION=X1|X2|X3|X4|X5|
        LX1|X1_2|SX1|
                    X3_2|LX3|SX3|
                    X2_2|LX2|SX2|
                    X5_2|LX5|SX5|
                    X4_2|LX4|SX4 @2 / SELECTION=LASSO;
RUN;QUIT;
*/
ODS GRAPHICS ON;
PROC REG PLOTS=(DIAGNOSTICS(STATS=NONE) DFFITS DFBETAS
PARTIAL);;
MODEL LDISTRIBUTION=LX1 LX3   / VIF INFLUENCE R PARTIAL SPEC;
ID X1 X3 X6;
OUTPUT OUT=SUMMARY STUDENT=RESIDUAL P=YHAT;
PROC UNIVARIATE NORMAL PLOT;
 VAR RESIDUAL;
run;
ODS GRAPHICS OFF;
quit;
```

Appendix F

Supplemental Information for Chapter 6

Table F.1: Chemical usage data (lbs/yr) for the water utilities that participated in testing the GHG emissions accounting tool.

	Water Utility				
Chemical (lbs/yr)	Utility A	Utility B	Utility C	Utility F	Utility G
Alum	256480	7140000		1434506	1905500
Ferric Chloride			446373		
Ferrous Chloride					
Chlorine		460000	720000	568646	32000
Sodium Hypochlorite		50000	4200		1971420
Lime		5300000	6185156		
Polymers			365600		8000
Carbon Dioxide					
Oxygen			34513474		
Sodium Hydroxide	343450			4609672	372000
Ammonia				348993	12000

Table F.2: Vehicle fleet fuel usage and annual mileage for Utility A.

Fuel	Amount Used gallons/yr		
Gasoline	1770		
Annual Mileage	Vehicle Type	Fuel Type	Model Year
18000	Light-Duty Truck	Gasoline	2005-present

Table F.3: Vehicle fleet fuel usage and annual mileage for Utility B.

Fuel	Amount Used gallons/yr		
Gasoline	17100		
Diesel	10000		
Annual Mileage	Vehicle Type	Fuel Type	Model Year
3408	Passenger Car	Gasoline	1999
18246	Passenger Car	Gasoline	2001
5496	Passenger Car	Gasoline	2003
20568	Passenger Car	Gasoline	2005-present
2340	Light-Duty Truck	Gasoline	1995
6456	Light-Duty Truck	Gasoline	1997
5532	Light-Duty Truck	Gasoline	1998
6288	Light-Duty Truck	Gasoline	1999
3450	Light-Duty Truck	Gasoline	2000
118356	Light-Duty Truck	Gasoline	2005-present
2040	Heavy-Duty Truck	Gasoline	1999
14100	Heavy-Duty Truck	Gasoline	2004
4620	Heavy-Duty Truck	Gasoline	2005-present
59724	Heavy-Duty Truck	Diesel	1960-present

Table F.4: Vehicle fleet fuel usage for Utility D.

Fuel	Amount Used gallons/yr
Gasoline	74170
Diesel	52421

Table F.5: Vehicle fleet fuel usage and annual mileage for Utility F.

Fuel	Amount Used gallons/yr		
Gasoline	1000		
Annual Mileage	Vehicle Type	Fuel Type	Model Year
30000	Light-Duty Truck	Gasoline	2005-present

Table F.6: Vehicle fleet fuel usage and annual mileage for Utility G.

Fuel	Amount Used gallons/yr		
Gasoline	3000		
Diesel	100		
Annual Mileage	Vehicle Type	Fuel Type	Model Year
12000	Light-Duty Truck	Gasoline	1999
11000	Light-Duty Truck	Gasoline	2001
10000	Light-Duty Truck	Gasoline	2002
14400	Light-Duty Truck	Gasoline	2004
1000	Heavy-Duty Truck	Diesel	1960-present

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