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Chapter 2

The Impact of an Ensemble of Solar Domestic Water Heating Systems on a Utility

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2.1 Abstract

The benefits to a utility and to the environment resulting from the installation of a large number of solar domestic hot water systems are identified and quantified. The environmental benefits of a large number of solar domestic hot water systems replacing conventional electric hot water systems include reduced energy use, reduced electrical demand and reduced pollution. The avoided emissions, capacity contribution, energy and demand savings were evaluated using the power generation schedules, emissions data and annual hourly load profiles from a Wisconsin utility. Each six square meter solar water heater system can save annually: 3560 kWh of energy, 0.66 kW of peak demand, and over four tons of pollution.

LIST OF ABBREVIATIONS

BACT	best available control technology
CAAA	Clean Air Act Amendments
CCI	Capacity Contribution Index
DHW	domestic hot water
DSM	demand side management
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GAMA	Gas Appliance Manufacturers' Association
HHV	higher heating value
MAAP	Mid-Continent Area Power Pool
MAIN	Mid-America Interpool Network
NAAQS	National Ambient Air Quality Standards
NARUC	National Association of Regulatory Utility Commissioners
PSCW	Public Service Commission of Wisconsin
SDHW	solar domestic hot water
SMUD	Sacramento Municipal Utility District
SRCC	Solar Rating and Certification Corporation
TSP	total suspended particulates
WCDSR	Wisconsin Center for Demand Side Research
WEB	Wisconsin Energy Bureau
WEPCO	Wisconsin Electric Power Company
WSEO	Washington State Energy Office

2.2 Introduction

In the late 1980s, the Sacramento Municipal Utility District (SMUD) was faced with an energy purchasing crisis due to the early retirement of their 900 MW nuclear power plant, Rancho Seco. SMUD customers voted to close the nuclear plant and to invest in renewable energy sources including solar domestic hot water systems. As a summer peaking utility, SMUD was faced with very high demand on hot sunny days and was forced to purchase expensive peak power. By taking the initiative of investing in renewable energy sources, SMUD placed a value on the avoided cost of meeting those peaks. In 1993, the utility offered customers performance based rebates of up to $863 per certified solar system (costing less than $3000) (IRT, 1993). Through a financing program, customers pay the remainder of the solar

domestic hot water (SDHW) system cost through their utility bills over the next 10 years. The savings from the SDHW system installment are typically more than the monthly payments for the system, yielding a positive monthly cash flow for the customer (Flavin, 1994). SMUD's goal is the installation of 12,500 systems by the year 2000 (Murley and Osborn, 1994). With a demand reduction of about 0.5 kW per installation, SMUD will have the equivalent of a 6 MW renewable power plant in terms of average peak reduction.

Domestic hot water (DHW) systems account for almost 6% of the energy consumption in the United States and are the second largest consumer of energy in the residential sector. The benefit of solar domestic hot water (SDHW) systems as energy saving devices is well known, yet SDHW systems comprise significantly less than 1% of the domestic water heating market. Previous economic analyses have focused solely on the energy impact of a DHW system. Due to high initial equipment costs and low conventional energy prices, solar systems cannot compete in such analyses.

Less well known is that SDHW systems can also reduce the peak demand for electric utilities. Many utilities' peak demand is coincident with the solar system peak performance. Due to large electric air conditioning loads, the peak load that a utility experiences usually occurs in the afternoon on the third or fourth consecutive day of hot sunny weather. The key to solar domestic water heating for summer peak clipping is the coincidence of the utility's peak load days and the sunniest, hottest days, when solar systems perform best. Other advantages of SDHW systems are utility emissions reduction and contribution to utility generating capacity.

Considering today's high cost of solar systems, economically justifiable payments by the utility to the solar system owner are necessary to implement an aggressive large scale SDHW program. The analyses in this chapter emphasize the viewpoint of the utility, which is much more complicated than the traditional consumer viewpoint of investing in solar equipment to save energy. The understanding of utility cost analysis and integrated resource planning is paramount. Annual solar system performance and the interaction of many solar DHW systems with a utility's traditional resource mix are analyzed to quantify the benefits of a diversified solar energy plant.

Hourly data analyses are utilized in this study. Previous studies have looked at SDHW systems as only energy saving devices and used average weather and average daily water usage statistics (e.g., the F-chart method; Beckman, Klein and Duffie, 1977). To accurately evaluate demand reduction, hourly, or shorter, water draw values must be obtained. If an electric water heater has a 4.5 kW element that is either on or off, then the peak demand of one system is 4.5 kW. But, when many systems are averaged, the resultant peak demand is significantly lower because the heating element demands are not concurrent. The first step in this analysis is to determine the effect a large number of conventional electric water heaters have on the utility's peak load. These conventional water heaters add to the utility's load year around since the demand for hot water is nearly independent of weather. The next step is to determine the reduction a large number of SDHW systems would have on the utility's peak load. Solar systems will reduce the utility system peak load due to the coincidence of hot sunny weather, the utility peak period, and the solar system peak performance. Demand reduction has value to the utility and thus should be passed through to the owner of the solar system.

The SDHW contribution to reduction in power plant emissions also has value. Detailed information about the characteristics of the utility's power generation capabilities must be available to do the analysis. As shown later, emission reduction cannot be accurately calculated by avoided energy analyses such as calculated by the F-Chart method. The emissions reduction from the plant at the margin (the last unit dispatched according to utility power demands) at the time the energy savings occur is the realistic approximation of avoided pollution resulting from the large scale replacement of DHW systems by SDHW systems.

Electric utility systems gain strength and economic value through a diversity of generating sources. Solar domestic hot water systems can add to the future vitality of a utility network by contributing to reliability and diversity of generating capacity. Since SDHW systems are dispersed throughout the community, a complete failure of one system has little effect on the grid. For an equivalent size fossil fuel generating facility, a failure can result in a large impact on the rest of the system for weeks at a time. From an environmental standpoint, renewable power generating technology is ideal, but from a reliability viewpoint, it also makes sense to have a diverse balance of fuel types and generating plants (PSCW, 1992).

The objective of this research is to identify and quantify the advantages and disadvantages to utilities and homeowners of an aggressive, large scale solar DHW program. The ultimate goal is the development of a utility specific approach to accurately evaluate the impact on the utility of an ensemble of SDHW systems. The analysis includes not only the determination of energy and demand reduction, but the evaluation of emission reductions and contribution to capacity. Results are given for one Wisconsin utility but the methodology developed here is valid for all utilities.

2.3 Domestic Hot Water Systems

Conventional residential hot water heaters are either gas or electric. The Gas Appliance Manufacturers' Association (GAMA) summarizes United States industry water heater shipments in their 1992 Statistical Highlights publication. For example, in 1991 44.6% of shipped DHW systems were electric, 50.9% were natural gas and 4.5% were LPG. It is estimated that eighty percent of residential water heater sales are replacement units, while the remaining twenty percent are installed during new construction with nearly one half of shipments electric DHW systems (EPRI, 1992).

All water heaters manufactured for sale in the United States after January 1990 must meet the federal standards of the National Appliance Energy Conservation Act. An Energy Factor is: "A measure of the overall efficiency of a water heater determined by comparing the energy supplied in heated water to the total daily consumption of the water heater (GAMA, 1992)." Thus, an Energy Factor rating is an estimate of the hot water energy output for each input of energy supplied to the water heater (WSEO, 1991). The range of the energy factor is from 0.90 for a 40 gallon tank to 0.79 for a 120 gallon tank.

Solar domestic hot water systems are used to preheat water for household use. Most systems have a conventional heating system included to provide water at the desired set temperature at all times. Although many different sizes and configurations exist, the main components include a solar collector, a storage tank and an auxiliary heat input. SDHW systems are designed with one or two tanks. In most systems cold water is removed from the bottom of the storage tank, circulated through the collector and replaced at the top of the tank. The circulation can be performed through active pumping or by natural convection (which takes advantages of the density difference between hot and cold water). For freeze protection, SDHW systems often have an additional antifreeze loop with a heat exchanger, or a drain-back system.

A two-tank, active SDHW system with an electric back-up tank and an antifreeze loop is shown in Fig. 2.1. A controller is usually installed in active SDHW systems to ensure that the fluid passing through the collector is heated (when sufficient solar radiation falls upon the collector) instead of cooled (during nighttime hours or periods of low incident radiation). For a single-tank configuration, the auxiliary heater is located in the upper third of the solar storage tank.

The Solar Rating and Certification Corporation (SRCC) is a source for solar hot water system ratings and information. The SRCC is an independent, non-profit organization sponsored in part by the United States Department of Energy. For rating purposes, the SDHW systems are subjected to a defined sequence of operating conditions representative of actual operation. The OG 300 rating and certification program for SDHW systems integrates the results of collector tests and system tests and standards for system durability, reliability, safety and operation (SRCC, 1993).

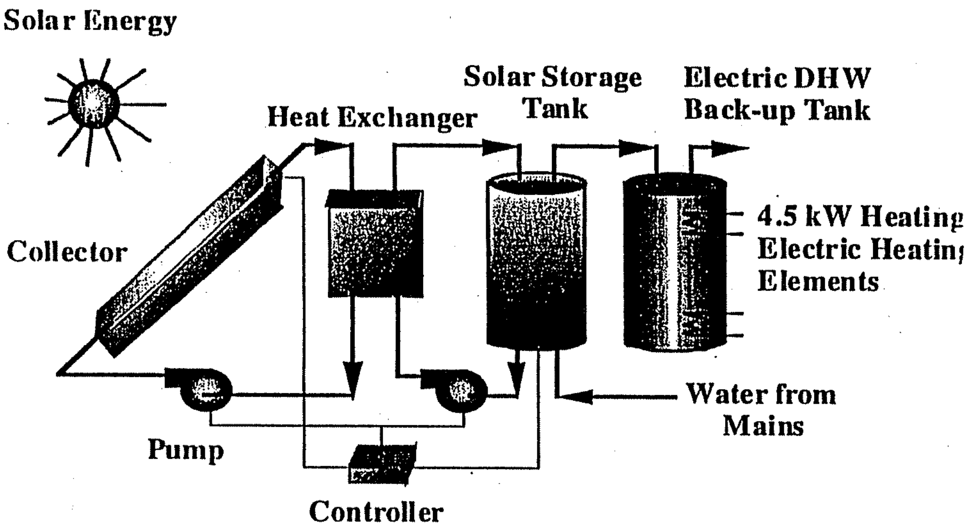

Figure 2.1: Schematic of an active SDHW system

The thermal performance ratings are determined using simulation models with TRNSYS (Klein *et al.*, 1994). The thermal performance is based on three equal water draws: 8 a.m., noon, and 5 p.m. Three daily average hot water draws of 55, 70, and 85 gallons are used to determine the equal water draws.

The performance rating is the daily energy savings provided by the solar system relative the load (SRCC, 1993) and is calculated as the difference between the energy used by a conventional water heater and the energy used (including parasitic) by a solar system. The SDHW system performance ratings begin at category A with less than 15 MJ of energy saved per day and increase by 5 MJ per day up to F, the highest category, with more than 35 MJ of energy saved per day.

While detailed TRNSYS models for the various commercial systems are available, basic configurations of various sizes were chosen for the Wisconsin utility impact analysis to provide a general basis for comparison. Since freezing temperatures are common during Wisconsin winters, only systems with freeze protection are considered.

While the variations of the water draw volume are the driving force for the DHW loads, standby losses and geographical and seasonal mains temperatures cause considerable variations in hot water loads. In Wisconsin the water mains temperatures range from around 35 to 60°F (depending on

Table 2.1: Renewable Energy Advance Plan

Renewables in Wisconsin: Historical Promises		
Advance Plan 4	1988	188 MW
Advance Plan 5	1990	148 MW
Advance Plan 6	1992	52 MW
Advance Plan 7	1994	432 MW

the water source and time of year). Also, most Wisconsin DHW systems are inside the home (e.g., a basement with relatively constant ambient temperatures), so the losses throughout the year are relatively constant. Therefore, the seasonal load follows the water mains temperature variation. Depending on the water mains source (lake, ground well, etc.), the water mains temperatures around the country can range from 35 to 90°F, so the seasonal hot water load variance in other areas may be less than or greater than in Wisconsin.

2.4 Utility Considerations

Fueled by federal and state tax incentives between 1978 and 1986, approximately 13,000 solar systems were installed in Wisconsin (WEB, 1993). Since then SDHW system installations in Wisconsin and in most of the US have stagnated. Integrated resource plans are called Advance Plans in Wisconsin. While the State of Wisconsin is considered at the forefront of integrated resource planning with inclusion of environmental considerations (NARUC, 1993), the Wisconsin utilities have continually decreased their projected levels of new renewable energy resources until 1994, as shown in Table 2.1. Recently, in Advance Plan 7, utilities have projected adding 423 MW of renewable sources during the twenty year planning period. Of this projection, only 6 MW are directly from solar sources, of which only 1 MW is to be installed by 2005.

An Advance Plan 7 Solar Task force used F-Chart and average daily gallon estimates to reach the following decision about SDHW impact on Wisconsin:

> "Therefore, under current assumptions and analysis methodology, no significant penetrations of solar water heating or PV systems are expected to become cost effective in the foreseeable future ...." (PSCW, 1994)

The study did not give any credit for demand reduction. Yet in 1991, a research team predicted that SDHW systems could reliably displace 1.3 kW of capacity and allow for $1,500 utility rebates per household (Carpenter *et al.*, 1991). This study was performed in Canada, which has a much harsher climate than Wisconsin. As noted earlier, SMUD currently gives credits for demand reduction to SDHW systems.

Most utilities are not as optimistic about solar energy as SMUD. Public power utilities are in a unique situation. While the utility share-holders expect to make a profit, the rates that utilities charge fall under the jurisdiction of the Public Service Commission (PSC) or the Public Utilities Commission (PUC) for the state in which they reside. State commissions have a commitment to economic efficiency. The utility regulatory agencies are responsible for ensuring that the customers receive reliable service at reasonable prices. At a higher level, the Federal Energy Regulatory Commission (FERC) also has jurisdiction over the utilities.

Since the rates that investor-owned utilities charge their customers are set by the states, utilities are driven to produce (or purchase) energy at the least possible price at any given time. There is little motivation for investment in alternative energy sources, due to their perceived high costs. Thus, government mandates and market energy prices as seen by the consumers have been the catalysts for change. This study evaluates solar domestic hot water systems from the utility and consumer viewpoint and shows that they can compete with conventional electric power generation.

In the past, public power utilities operated (and were regulated) such that their profits were directly linked to electricity sales. Efficiency investments countered the economic interests of the shareholders to whom the utility executives were responsible. The National Association of Regulatory Utility Commissioners has pushed regulators to compensate the utilities in a variety of ways for lost profits (reduced electricity sales) by allowing utilities to earn equal or greater profits on saved power.

The idea that utilities should participate in energy conservation or fuel switching options seems counterintuitive, but public power utilities are not operating under normal market regulations. Their monopolies are currently protected by governments, although this may significantly change in the future with some form of deregulation. The Power Utilities Regulatory Policy Act (PURPA) of 1978 requires utilities to purchase renewably generated electricity at the 'avoided cost' of power from conventional sources. What is the value of electricity that could be 'generated' by an aggressive solar domestic hot water policy?— We will evaluate this question below.

Table 2.2: Wisconsin Energy and Demand by Sector WCDSR, 1994

Economic Sector	Annual Energy (GWh)	Summer Peak Demand (MW)
Agriculture	1,599	335
Commercial	14,975	3,206
Industrial	21,360	3,367
Residential	15,925	3,429

2.4.1 Utility Load Characteristics

The majority of utilities in the United States are termed 'summer peaking utilities'. Seasonal peaks formerly occurred in the winter, due to electric resistance space heating, but as more households switched to gas furnaces in the winter and electrically driven air conditioners in the summer, the air conditioning load on utilities has superseded the winter heating one.

The ideal load curve is flat, meaning that capacity requirements are constant. Baseload power plants could then run at full capacity (and at highest efficiency). Since the load does vary, a utility needs to have extra capacity on hand even though it may only be needed for a short period of time. Gas combustion turbines are attractive from a utility standpoint for extra capacity due to their low initial costs, even though their operating costs are high. Utilities can rationalize the more expensive operating costs because the combustion turbines will seldom be needed. Even so, the high gas turbine operating costs are part of the reason for the difference between on- and off-peak customer rates.

Table 2.2 shows annual energy and demands in Wisconsin in different use sectors. Since residential customers account for 30% of the annual energy requirements and the highest peak summer demand, utilities often look to the residential customers for energy saving programs and demand-side measurement strategies.

The difference between the cost of on- and off-peak electricity has encouraged load shifting programs, such as ice storage and demand-side measures, such as compact fluorescent light bulbs and appliance timers. It is through demand side management that utilities can justify paying people *not* to use energy at certain (peak) times of the day. There are demand side management advantages to SDHW systems, and it may be less expensive for the utility to invest in these solar systems than to operate their peak gas combustion turbines.

Table 2.3: 1991 Wisconsin and U.S. Energy Consumption by Resource (WI 1993-4 Blue Book)

Resource	US Btu/Capita x 10^{-6}	Wisconsin Btu/Capita x 10^{-6}	WI as % of US
Petroleum	110	90	82%
Natural Gas	79	66	84%
Coal	60	80	134%
Wood	?	10	?
Hydro	5	2	31%
Nuclear	26	24	93%
Total	295	275	93%

Evaluation of new generating or demand-side options is based on least cost, but the types and definitions of the costs that are reviewed vary greatly. The most controversial of these costs today is the environmental, or societal, cost. Since it is difficult to assign monetary values, liability, or source to some environmental costs, most utilities do not even consider them, unless their inclusion is dictated by government.

Wisconsin is the focus of this study. Its resource mix, in comparison to the rest of the United States, is shown in Table 2.3. This Table, lending a national perspective to the Wisconsin analysis. In 1991, Wisconsin's total energy use per capita was about 93% of the national average. Wisconsin utilities show a heavy reliance on coal in comparison to the rest of the United States.

Integrated resource planning gives a strategic opportunity to incorporate/internalize environmental externalities in a manner that is economically sensible. The Public Service Commission of Wisconsin states the purpose of integrated resource planning, the Advance Plan process, as follows:

> "The Advance Plan is filed jointly by Wisconsin's electric utilities every two years, pursuant to 196.491 Wisconsin Statutes and Wisconsin Administrative Code Chapter PSC 111. The purpose of the Advance Plan is to inform the Public Service Commission of Wisconsin and the general public of the utilities' plans for the future."

> "The objective of the integrated resource planning process is to assure that utility customers are provided with safe and reliable service while reasonably balancing the costs and benefits of providing that service. (PSCW-AP7, 1994)."

Since the Public Service Commission of Wisconsin is concerned with system reliability and load forecasting, the capacity levels of utilities are an important part of integrated resource planning. Reserve generating capacity is considered the difference between the utility's generating capacity and the customer's demand for energy. Reserve generating capacity is not to be confused with excess capacity, which is unused. Generating capacity may become unavailable due to: planned maintenance; breakdowns which force units out of service; failure to meet scheduled start up dates for new generation units; unavailability of fuel; regulatory action; limitations in or absence of the transmission system (PSCW, 1994).

The Mid-America Interpool Network (MAIN) and the Mid-Continent Area Power Pool (MAPP) are networks of electric utilities, based on the idea that there is safety in numbers from a reliability perspective. Each network has its own set of rules concerning the need for reserves and each member utility's responsibility. Each utility is responsible for its own load, yet provides a set reserve margin to ensure reasonable reliability and optimal economic operation. Without MAIN, Wisconsin utilities would need to have approximately 50 to 100% more reserve capacity to provide the same level of reliability that is achieved through the network (Arny and Harsevoort, 1994). The planned reserve generation capacity margins for Wisconsin utilities range from 15 to 18%

1991 is considered a representative year for Wisconsin utilities. The information for each utility in Wisconsin was obtained from Advance Plan 7, D24: Power Generation, in which the data are the result of production cost analysis. The 1991 utility load profile, together with the 1991 ambient temperature and radiation data, were obtained for the Wisconsin Electric Power Company (WEPCO), located in Milwaukee, Wisconsin. The 1991 hourly utility demand in MW is shown in Fig. 2.2. This figure demonstrates the winter and summer seasonal utility load peaks as well as the cyclic day and night pattern.

Fig. 2.3 shows how the August load directly follows the ambient temperature. While the peak temperature occurred on Monday August 26, the peak utility demand occurred on Thursday, August 29, due to electric air conditioning loads on the fourth of four consecutive hot, sunny days. Fig. 2.4 shows the utility load for August 29 in detail. Superimposed on this figure is the estimated average demand of many electric domestic hot water heaters. Eliminating the electric demand of domestic hot water will provide about 0.5 kW of demand reduction for each system.

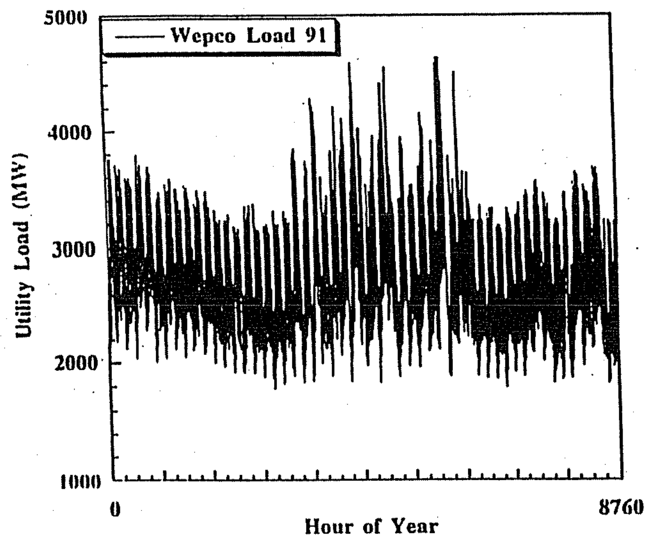

Figure 2.2: WEPCO of Milwaukee 1991 load

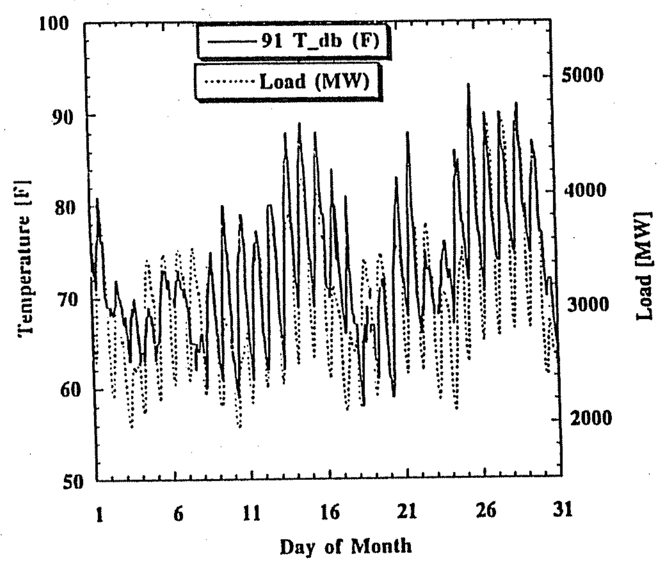

Figure 2.3: August 1991 Milwaukee temperature and WEPCO load

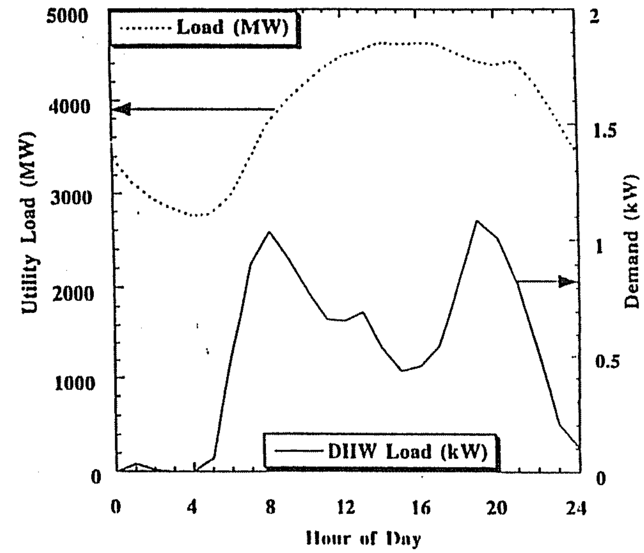

Figure 2.4: WEPCO August 29, 1991 utility load and average electric DHW for one household

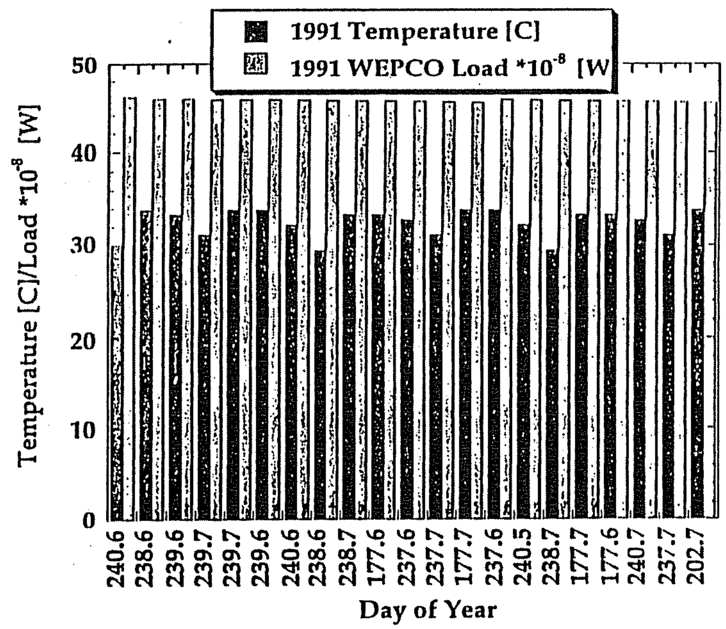

Figure 2.5: Top tenty 1991 WEPCO demand hours (& temperature)

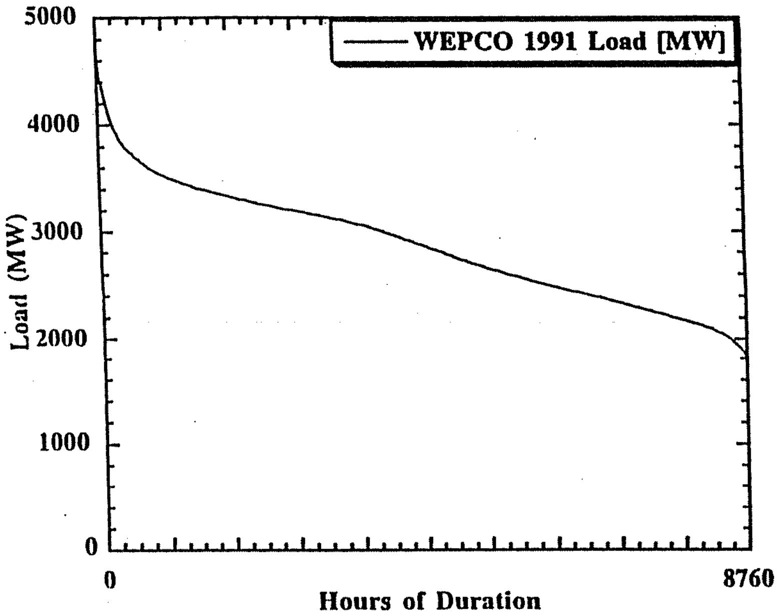

Figure 2.6: WEPCO 1991 load duration curve

Typical for a summer peaking utility, the top twenty peak utility demands all occurred on hot, sunny weekday afternoons. The peak days, and their respective temperatures are shown in Fig. 2.5. Power is produced expensively during these peak utility demand hours with combustion gas turbines, or purchased expensively from other utilities on the grid.

The timing of demand and energy reductions relative to the utility system demand need to be discerned, to determine the benefit to utilities of alternative water heating options. The type of plant (and its characteristic emissions and costs) at each hour of the year is directly related to the magnitude of the utility demand at that hour. The load duration curve is the most efficient way to provide the necessary information.

A load duration curve is obtained by plotting the hourly demands of the utility in descending order. The utility load changes throughout the day and throughout the year. However, a load duration curve, as shown in Fig. 2.6, disregards the timing of the load and shows the number of hours that the utility experienced a certain level of demand. A load duration curve can be used to determine the type of generation unit that is dispatched for each level of utility load. The power generation schedules (in order of least cost for this analysis) can be applied to the load duration curve, to predict the plants that would most probably be operating at any hour, based on the level of load.

2.4.2 Environmental Externalities

Utilities use various forms of power generation to meet the system load, beginning with the plant with the lowest operating costs. Each of these plants incurs a certain cost to the utility and to the environment. Coal, oil, and natural gas plants release varying levels of carbon dioxide, sulfur dioxide, oxides of nitrogen, and particulates. The cost to the environment for these pollutants can be converted into \$/ton produced. Using a marginal plant analysis based on a least cost production model, a utility's avoided emissions from the installation of SDHW systems can be evaluated and the impact of the solar systems on the utility can be quantified, as shown later in this chapter.

Economists define externalities as the effects of actions by one party that provide costs or benefits to a third uninvolved party (Temple, Barker and Sloan, 1990). These effects can be positive or negative. Externalities are generated by both producers and consumers. Environmental externalities can be defined as the changes in economic welfare that manifest themselves through changes in the physical-biological environment (NARUC, 1994). If the environmental costs are external to the production decisions of a utility, then the customer rates for electricity do not reflect the full cost to the consumer (or to society as a whole). Theoretically, all the external costs should be internalized. The external costs of electricity need to be considered for four important reasons (NARUC, 1994):

- Risk management: Rate payers need to be protected from rate increases caused by future utility liability for environmental damage.
- Social equity: When one group benefits from low cost electricity at the expense of another group who experiences the accompanying environmental costs.
- Economic innovation: Renewables and conservation measures can be given a fair comparison to traditional supply-side resources.
- Utilities are franchised monopolies vested with a duty to serve the public interest, a responsibility that includes environmental protection (Pace, 1990).

Some public solutions to remediate the difference between marginal social costs and industry cost involve regulation, corrective taxes and tradable permits. Imposing a corrective tax (environmental adder or externality monetization in \$/ton) provides some incentive for the pollution abatement at a somewhat "socially efficient" level.

No source of electrical generation is completely benign to the environment, but renewable energy sources do emit substantially fewer pollutants than fossil fuel combustion (PSCW-AP6, 1992). The emissions from airborne pollutants resulting from electric utility operations such as the burning of fossil fuels are listed below. Not only are their individual effects significant, but their synergistic environmental effects (greater than the sum of their separate damages) may be a factor (Pace, 1990).

- Carbon dioxide (CO_2) — Global warming is the primary concern. Tree planting costs are sometimes the proxy for valuation of the greenhouse gas potential (Pace, 1990).
- Sulfur dioxide (SO_2) is primarily produced from artificial causes such as oil and coal combustion. SO_2 is a precursor of acid aerosols that result in acid rain. SO_2 also combines with particulates, entering the digestive system of animals (El-Wakil, 84).
- Oxides of Nitrogen (NO_x) cause damage to human health, agriculture, and animals. NO_2 attaches to hemoglobin, depriving the blood of oxygen, and also forms acid in the lungs (El-Wakil, 1984).
- Particulates (TSP) can be solids or liquids in sizes ranging from 1 micron to 100 microns or more. They result in both health effects by penetrating deep into the lungs and visibility effects by contributing to smog in urban areas.

Opponents of the pollution monetization argue that nature produces more airborne contaminants, through natural processes such as volcano eruptions, plant and animal decay, than any fossil fuel source. El-Wakil counters that argument:

> "Contaminants are those materials, radiations, or thermal effects that are *added* to the environment beyond what nature itself puts into it. In the 1960's it was estimated that, globally, nature puts into the environment some 10 times the amount of contaminants that people put into it. The contribution of nature is, however, diffuse and thus largely harmless, whereas the contribution by human beings is more localized and concentrated. It follows that pollutants are contaminants in concentrations high enough to adversely affect something that people value, such as their environment and health." (El-Wakil, 1984)

In 1990, the Environmental Protection Agency (EPA) passed the Clean Air Act Amendments (CAAA). The goal of CAAA is to achieve significant environmental benefits through reductions in sulfur oxide (SO_2) and oxides of nitrogen (NO_x) emissions, the primary components of acid rain (EPA, 1991). The CAAA define guidelines through the New Source Performance Standards, National Ambient Air Quality Standards (NAAQS) and requirements for use of the "best available control technology" (BACT) for SO_2 and other criteria (Temple, Barker and Sloan, 1990). Title IV of the CAAA sets standards for power utilities. Power plant regulations are separated into three categories (EPA,1991): State Implementation Plans (which have

Table 2.4: Monetization of Airborne Pollutants in Dollars per ton*

Pollutant	PSCW	Mid-Range	High
Carbon	-	$26	?
CO_2	$15.64	$15-$18	$26.45
SO_2	$250	$170 -$2000	$4006
N_2O	$2814.70	$2700	?
NO_x	-	$400-$1640	$7934
CH_4	$156.38	$150	?
Particulates	-	$2380	?

*CO_2: $26.45 Maine (Flavin, 1994); SO_2: $2,000 =EPA fine; Maine=$1,873 for SO_2 (Flavin, 1994); $4,006 (Pace, 1990); NO_2: $2,700 (NARUC, 1994); NO_x: $400 (WI DNR), $7,934 Maine (Flavin, 1994); Particulates: $2,380 (Pace, 1990)

variable emission limits); New Source Performance Standards (which mandate a 1.2 lbs SO_2/MBtu limit for compliance coal plants); and Revised New Source Performance Standards (which require a 70-90% reduction of SO_2 with flue gas desulfurization (via scrubbers).

The primary goal of the legislation is the reduction of SO_2 by 10 million tons below 1980 levels (EPA, 1991). The CAAA takes a two step approach to control of pollutants. A primary standard set for pollutants is designed to protect health. A secondary standard for pollutants is designed to protect welfare. The basic principles concerning utilities are (Heinz, 1991).

- Phase I: Utilities have to achieve an average system emission rate of 2.5 lbs of SO_2 per MBtu by 1995. 110 mostly coal-burning, electric utility plants located in 21 Eastern and Midwestern states are affected.
- Phase II: Utilities are required to have an average system emission rate of 1.2 lbs of SO_2 per MBtu by 2000. All existing utility units with an output capacity of 25 MW or more and all new utility units will be affected.
- Post-2000: Any growth in emissions must be offset by an equal emission reduction from another source.

One of the most prominent results of the CAAAs is its effect on the coal industry. To meet the sulfur dioxide limits, utilities pushed the industry for lower sulfur coal. In Wisconsin the delivered cost of energy from coal varies from 1.09 to 1.94 $/MBtu, while the sulfur content, mining cost, and transportation cost for coal span an even broader range of values. It is sometimes advantageous to pay more for transportation in order to receive lower sulfur coal, and thus lower the costs of sulfur emissions.

Another important result of the CAAAs of 1990 is that emission allowances can be traded. There is an SO_2 cap for the United States and utilities can buy and sell SO_2 allowances on the Chicago Board of Trade. If compliance with Title IV legislation is not achieved, the owners or operators of delinquent units must pay $2,000 per excess ton of emissions (EPA, 1991). Violating units must also offset the excess SO_2 emissions with allowances in an amount equivalent to the excess. Even with these regulations, there are still local emission limits.

The economic incentive to reduce emissions, and the incentive to find less expensive ways to control emissions is then left to the utility. If one utility puts scrubbers on their stacks, or invests more in renewables, thus producing less SO_2 emissions, they can sell their allowances to another utility which might be exceeding its allowable limits. The value of each emission can be thought of as the conservation cost versus the cost of buying more allowances.

A New York Times article described an agreement between two utilities, Niagara Mohawk of New York and Arizona Public Service in which Niagara Mohawk's sulfur dioxide allowances (obtained from Arizona Public Service in exchange for carbon dioxide reductions) were "donated" to an ecology group (Passell, 1994). The tax benefits that Niagara Mohawk received for the SO_2 allowance retirements are then being invested in conservation programs. There was even one study about the profitability of one utility investing in another utility's DSM measures to save money, if they purchase electricity from that utility (Orans, Woo and Pupp, 1993).

Table 2.4 provides a range of pollutant monetization (PSCW, mid-range, and high) from various published sources. The means by which the numbers were produced are varied. Some public power utilities argue that the supposed cost of these externalities have already been internalized through their plant production, pollution, safety and control strategies. In addition, electric utilities resent the additional scrutiny that power producers receive in comparison to industry and other private sources, which are also responsible for many pollutants. Although electric utilities feel singled out, inclusion of environmental externalities from a utility planning perspective is not without merit. Integration of externalities into resource planning is already here. Utilities need to decide whether to take a pro-active or reactive stance towards their valuation.

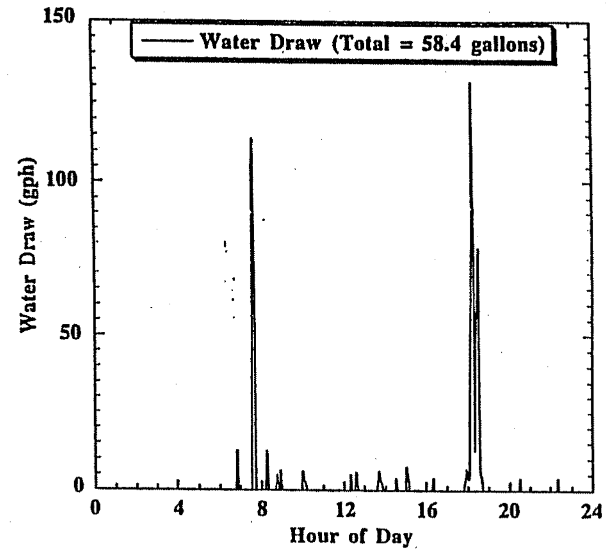

Figure 2.7: WATSIM family of four — typical Wednesday

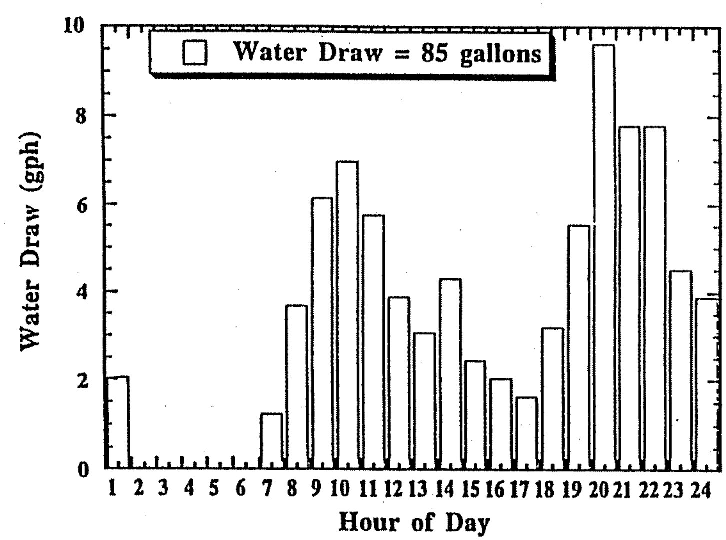

Figure 2.8: RAND average hot water load profile (Klein *et al.*, 1994)

?.5 Residential Water Use

The first issue is the evaluation of diversified electrical demand through iversified water draws. Residential water draws are the subject of much tudy and debate as water heating is the second largest consumer of energy in he residential sector. An attractive feature of water heating load reduction s that, unlike heating and cooling loads, water heating loads are somewhat eason independent. Many studies and demographics analyses have been erformed to estimate the average household water draw (Pontikakis, and)ouglas, 1994). While an individual profile for a family of four with two vorking parents may look like Fig. 2.7, not everyone washes their hands, howers, does laundry, or prepares meals at the same time. Therefore, the werage water use of many households is shaped differently than that for ny individual profile. Most studies agree on a general shape for the average lraw. The magnitude of the average daily draw may vary regionally from i0 gallons per day to 120 gallons per day (EPRI, 1992), with some seasonal 'ariance, but the general average shape is known. The RAND (Mutch, 1974) rofile is an average hot water use profile that is widely referenced and is hown in Fig. 2.8.

The magnitude and timing of residential hot water draws are needed o evaluate the impact of many DHW systems on a utility. Estimates of itility customer hot water usage can be obtained by monitoring the DHW quipment, conducting customer usage surveys, or both. Customer surveys re dependent on market research problems such as self-reporting and staistical analyses. Low level monitoring (utility billing analysis, end-use meering, or Btu metering) requires long monitoring periods and large sample izes. While detailed monitoring (continuous data logging of many variables) an reduce the needed sample size and the duration of the testing period, he per-site costs are significantly higher than low level monitoring (Chrisensen and Burch, 1994). Thus, metering of large numbers of households is rohibitively expensive, time consuming and dependent on the accuracy of nonitoring equipment. Both surveys and monitoring programs are sensitive o sample size.

To circumvent these problems, a water simulation program, WATSIM, ased on metered data and survey results, but with extended demographics nd probabilities, was employed. WATSIM was developed by the Electric Power Research Institute (EPRI) and contains algorithms based on metering xperiments, previous research, and statistics (Hiller *et al.*, 1994). WATSIM nade use of an EPRI developmental study that utilized sixteen predictive quations with up to nine independent variables. The equations were used to stimate either weekday or weekend-day hourly average hot water consumpion within eight daily time periods (EPRI, 1985). This study estimated

that in general, the predictive equations explained about seventy percent of the actual variation in average hot water consumption.

WATSIM is believed to be the best source of hot water load information available today. WATSIM has two main purposes: to simulate various water heater performances, and to create water draw profiles (EPRI, 1992). While WATSIM can model electrical resistance, fossil fuel fired, and heat pump driven residential hot water heaters, it does not model solar water heating systems. To estimate the diversified electrical demand of a large number of electric and solar DHW systems, a large number of individual profiles must be simulated in a program which can model both solar and electric DHW systems. WATSIM is used to create the input water draws for the TRNSYS (Klein *et al.*, 1994) system analyses.

The types of input that may be manipulated for each household are events and family characteristics. An abbreviated set of events appears in Table 2.5. Hot water events are set to occur according to the number and characteristics of the persons living in a household. Annual simulations (for one family) also contain statistics for vacations, weekends, laundry days, and out-of-town guests. The day of the week for water draws is also a user input. The most distinct differences in WATSIM's daily average water draw profiles are between weekdays and weekends.

While it is possible with WATSIM to follow one family throughout an entire year, an option in WATSIM provides the diversified water use of multiple families on a particular day. The average effect of numerous households can be seen in Fig. 2.9 for 10 and 300 households. The instantaneous hot water demand of the average household clearly decreases with increasing sample size.

Up to 300 sets of 'different' household profiles may be created with WATSIM, while up to 900 sets of 'different' customer profiles are achievable with some manipulation outside of the main program. The average of 900 households for five different days of the week and the same random seed are shown in Fig. 2.10.

The spikes in Fig. 2.10 indicate that a large number of households were using hot water during the same five minute time period, which is highly improbable. One explanation for this problem could be that the different days of the week have some set time scheduling consistencies. To test the effect of the random number generator (independent of the day of week), the average hot water draws for 900 households were created for the same day using 10 different random seeds as shown in Fig. 2.11. These 10 averages of 900 were then averaged. The resulting thick line is thus the average of 9,000 'different' residential customer water draws. The variance is greater than

Table 2.5: WATSIM Hot Water Events Table

Event Hot Water Characteristics						
Event	Line #.	Event #	GPM	ON (s)	OFF (s)	POU* Temp.
profligate shower	0	0	7.0	500	0	1
average shower	2	1	6.0	250	0	1
conserving shower	4	2	2.0	180	0	1
bath	6	3	7.0	300	0	1
wash-up	7	4	2.0	100	0	1
hands/face	9	5	2.0	30	0	1
* small c.w./WC	11	6	1.5	240	0	0
small c.w./HC	12	7	3	240	0	0
small c.w./WW	13	8	1.5	240	600	0
small c.w./HW	15	9	3	240	600	0
large c.w./WC	17	10	1.5	390	0	0
large c.w./HC	18	11	3	390	0	0
large c.w./WW	19	12	1.5	390	900	0
large c .w./HW	21	13	3	390	900	0
weekday breakfast	23	14	2	20	15	1
weekend breakfast	31	15	2	20	15	1
lunch preparation	43	16	2	20	15	1
dinner preparation	51	17	2	20	15	1
lunch dishwash	68	18	2	45	30	1
dinner dishwash	78	19	2	45	30	1
machine dishwash	91	20	6	60	600	0
cleaning	95	21	2	30	120	0

* "c.w." represents clothes washing and C, W, and H represent cold, warm, and hot respectively for the wash and rinse cycles. POU is point of use.

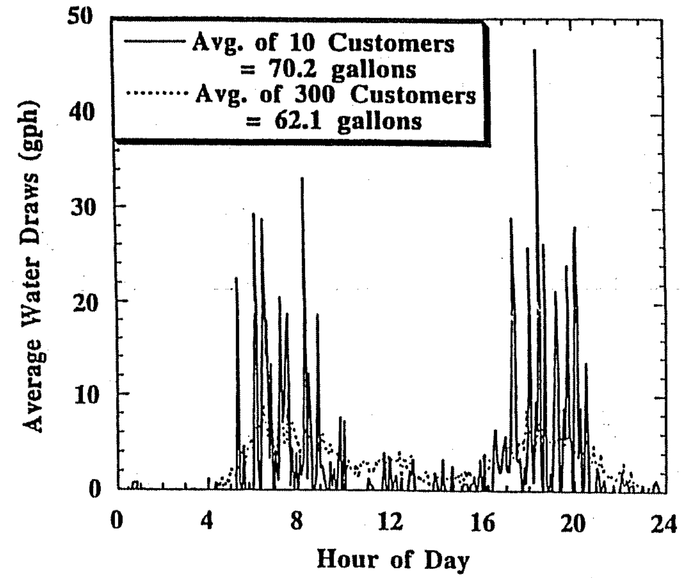

Figure 2.9: WATSIM Tuesday water draws: 10 and 300 averaged

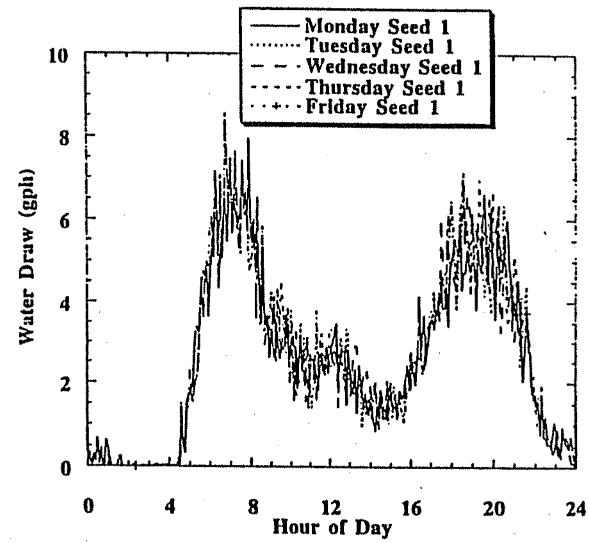

Figure 2.10: WATSIM weekday draws of 900 customers using random seed 1

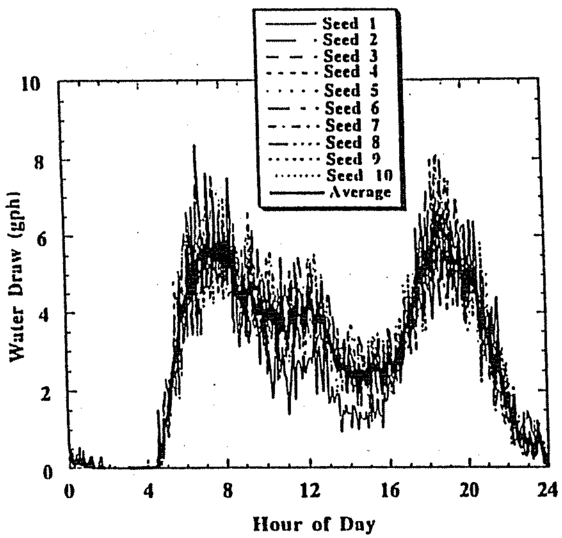

Figure 2.11: WATSIM Tuesday draws: average of 900 customers using 10 random seeds

expected, casting some doubt on the statistical accuracy of the WATSIM load profile.

The conclusion from Fig. 2.11 is that a large number of WATSIM hot water draws are not truly independent. If the individual hot water draw profiles from WATSIM were used in TRNSYS to model the diversified electrical demands of different DHW systems, the statistical problems would carry over into the electric utility impact analysis and the simulation time requirements would be excessive. Since the time of day and magnitude of the electrical demand are critical to the utility impact analysis, individual WATSIM hot water draw profiles were not used in this analysis.

Average weekday and weekend-day loads can be derived from WATSIM that agree with other accepted metered and utility produced average hot water loads. The 900 'spiky' averages for 10 different random seeds, (for five different weekdays and two different weekend-days) were "smoothed" to yield the weekday and weekend-day average hot water draws (in ten minute intervals) shown in Fig. 2.12.

An ASHRAE paper reported a detailed analysis of residential hot water usage research (Pontikakis, and Douglas, 1994). Pontikakis listed four separate sources, with varying sample sizes, that estimated the average residential hot water load profile. Although the amount of daily hot water

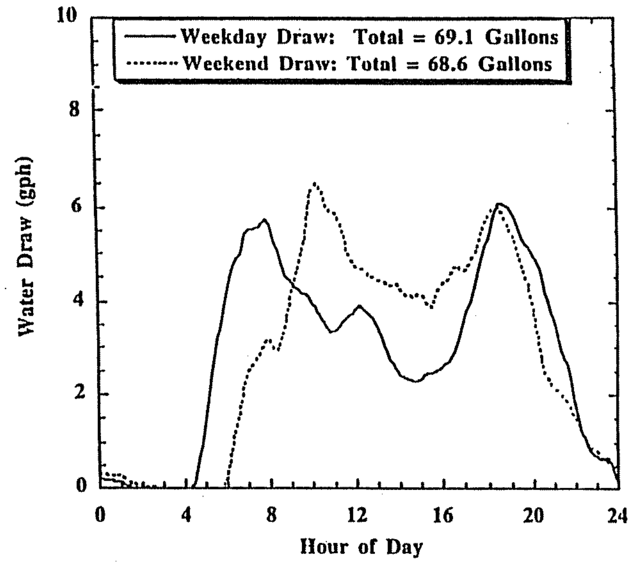

Figure 2.12: WATSIM derived average residential water draw profiles

usage varies in these profiles, the incidence of the hot water draws is similar to the WATSIM derived average weekday hot water draw and the RAND profile. To compare the six average profiles on a consistent basis, they were normalized in Fig. 2.13. Except for the RAND peak in the afternoon, the magnitudes and timing of the hourly hot water draws are in surprisingly good agreement. The similarity of the draws lends support for the WATSIM derived average draws chosen for the DHW system analysis.

2.6 TRNSYS Simulation Model

TRNSYS, a modular transient system simulation program, (Klein *et al.*, 1994) can simulate any type of solar, electric or fossil fuel-fired DHW system. The usual solar DHW and electric DHW studies performed with TRNSYS use a tank model with two on/off 4.5 kW heating elements. The heaters are controlled so that only one can be on at a time but when on, the element is on at full capacity until the set temperature is reached, then it turns off. This on/off behavior requires a large number of runs (with different individual hot water draws) to create the average diversified demand of utility interest.

TRNSYS also has a model for electric DHW systems that uses energy rate control (referred to as a zip heater in this analysis). Energy rate control adds exactly the amount of energy needed to maintain the set temperature, so that electrical demand directly follows the hot water draw. Except for differences

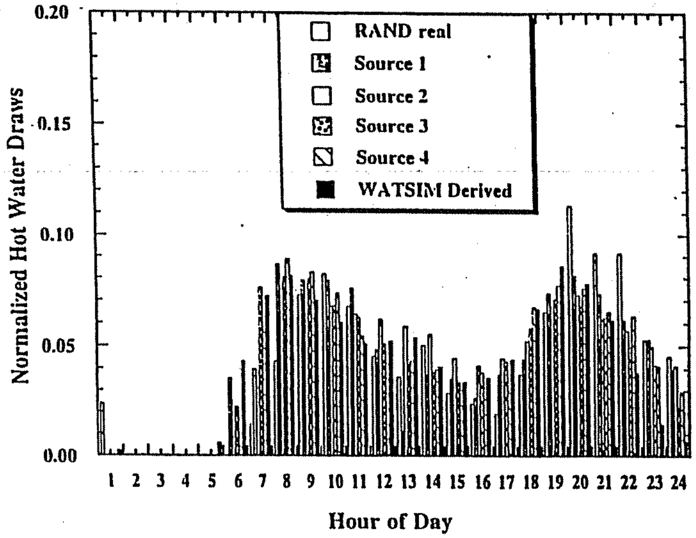

Figure 2.13: Normalized hot water draws compared

in calculated tank losses to the environment, the same integrated energy requirements will result using the zip heater as using the on/off heater. The question that remains is: can the same diversified demand be achieved with an average water draw with energy rate control, as with the average of hundreds of individual electric demands from hundreds of individual hot water draws with the traditional on/off heater analysis?

Although diversified average hot water draw profiles for weekdays and weekends have been obtained from WATSIM, modeling a single system with an average water draw and on/off heating elements does not produce the demand reduction achieved through modelling a large number of varied, individual profiles. To evaluate the demand, energy, and emission reduction for a large number of solar domestic water heaters, it was initially thought that one hundred to one thousand representative draws would have to be simulated on an annual basis with on/off (temperature level) control. Hourly calculations for one DHW system for a year with a diversified draw (1,000 profiles) results in 8,760,000 simulated hours needed to analyze the impact of one type of solar water heater on an annual basis. Analyzing just ten different solar DHW systems, the resultant eighty-seven million TRNSYS

simulated hours would take an unreasonable amount of computational time to complete. Even if only ten different draw patterns were needed, instead of one thousand draw patterns, 87,000 simulated hours would be required; this is still too much,— so a shortcut method must be found.

Using TRNSYS, the electrical load for an average water draw profile can be simulated with the same tank characteristics as for a typical 4.5 kW on/off electric water heater, but with one modification: the heating elements are removed and replaced by an energy rate controlled "zip heater". A one-tank model (with a heater that is one third of the way down) can be modeled with a storage tank of approximately 67% for storage of solar energy and the remainder electrically heated. In this application, a zip heater replaces the element that is normally in the upper one third of the tank.

Since a constant standby loss term is applied to the electrical demand of the auxiliary zip heater, the two-tank systems have a slightly higher electrical demand during high solar performance periods than a real on/off heater model with variable standby losses would have. During peak solar system performance, the back-up tank temperature could exceed the set temperature, partially compensating for the need for auxiliary energy when the tank temperature falls due to the tank losses. Unfortunately, the zip heater model does not reflect this behavior. Therefore, the auxiliary demand of a two-tank system actually provides an upper limit for the possible demand during afternoon periods (peak solar system performance). The lower limit is zero demand during peak solar DHW performance.

To test the accuracy of the zip heater model, a FORTRAN program was written to produce 100 'random' individual daily draw profiles from the average weekday hot water (ten minute interval) draw profile derived from WATSIM. Fifty gallons per hour during a ten minute interval is a realistic residential hot water draw. A simplified explanation of the program is as follows.

If there were an average draw of five gallons per hour at eight a.m., ten random numbers between 1 and 100 would be chosen. Each random number corresponds to a profile number (customer) and, for each of these customers, the hot water draw at eight a.m. is set to fifty gallons per hour. All other customers (the other ninety numbers not chosen) are assigned a hot water draw of zero gallons per hour. Thus, when the hot water draws for all 100 customers are averaged at eight a.m., the result is five gallons per hour. This process is repeated for ten minute periods of the average daily water draw profile, thereby creating one hundred individual profiles. When these individual hot water draws are averaged, the exact original average hot water draw results. This procedure avoids the statistical problems evident

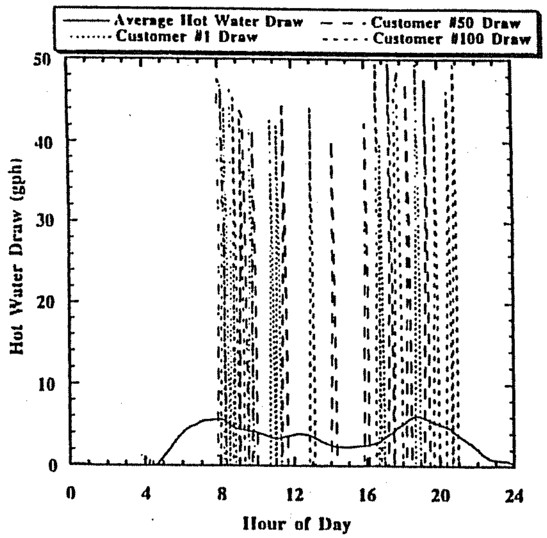

Figure 2.14: Random hot water draw profiles

with the WATSIM program. The average weekday draw profile and three of the 100 individual profiles are shown in Fig. 2.14.

The electric demand of conventional 80 gallon electric water heaters was calculated four different ways and they are compared in Fig. 2.15. Line A of Fig. 2.15 is the electrical demand for both (since they are nearly identical) the average daily hot water draw with an energy rate controlled zip heater and the average of 100 individual draw profiles each run for one day with a zip heater. Line B is the electrical demand using the average daily hot water draw profile with a 4.5 kW on/off electric water heater. Line C, the best estimate of actual behavior, is the average electrical demand of one hundred different individual hot water draw profiles with a 4.5 kW on/off water heater. Since lines C and A are nearly identical, the computation of hundreds of individual hot water draws is unnecessary if a zip heater is used with the average hot water draw.

Fig. 2.15 shows that the combination of a zip heater and an average water draw can be used to model the diversity of a large number of electric-only DHW systems. This figure could also be considered a 0% solar fraction SDHW system. The other limiting case is a one 100% solar fraction system, in which the electrical demand is zero. To test a mid-range case, a small (only 30% annual solar fraction) system was simulated. Milwaukee weather

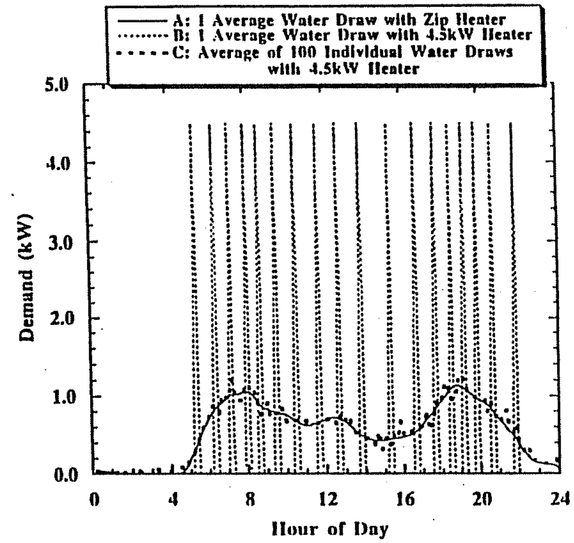

Figure 2.15: TRNSYS demand profiles for electric DHW models

from the third day of a series of 4 days of hot sunny weather (coincident with WEPCO's 1991 peak demand day) was used to generate Fig. 2.16.

Line A of Fig. 2.16 is the average electrical demand of a single simulation using the average daily water draw profile with a zip heater. Line B is the electric demand of a single SDHW system with a 4.5 kW on/off backup heater, which clearly has demand peaks of 4.5 kW. Line C, the most realistic situation, is the average electrical demand of 100 individual water draw profiles, each with a 4.5 kW on/off water heater. Line D, which falls almost on top of line A, is the average electrical demand of 100 individual systems using 100 different water draw profiles and all using energy rate controlled zip heaters.

Line C is the conventional on/off method result, and Line A is the zip heater method. The difference in their solar fractions is less than one percent. As seen in both Fig. 2.15 and Fig. 2.16, the zip heater method closely reproduces the average of 100 individual households and is thus considered as a valid technique for evaluating hundreds of on/off heater runs from both an energy analysis and electrical demand perspective.

The zip heater approach is an efficient way to achieve the goals of this research. Not only does this method significantly reduce computation time, but it allows the user to experiment with a range of water draw profiles,

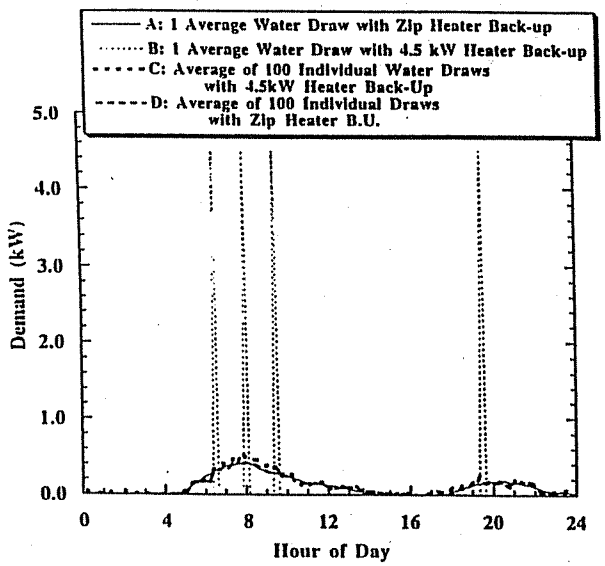

Figure 2.16: TRNSYS demand profiles for SDHW Models. Solar system: 2.5 m^2 collector panel area with 80 gallon electric back-up tank. Daily solar Fractions: A: 79.5%, B: 76.6%, C: 78.3%, and D: 78.3%

various tank sizes, and different utility loads easily and without the necessity of knowing the details of the thousands of individual water draws.

2.7 Utility Impact Analysis

This research evaluates the true costs of solar water heating by analyzing:

1) contribution to utility capacity,
2) annual energy reduction,
3) peak demand reduction, and
4) emission reduction for an ensemble of SDHW systems.

To calculate the annual impact of solar DHW systems on a utility, an hourly utility load profile for a representative year must be analyzed. The weather is a driving force for much of the utility load, due to temperature effects on residential heating and cooling requirements and is the primary driving force for the solar domestic hot water system. Thus, weather data for the same year as for the utility's hourly load must be available. Typical Meteorological Year (TMY) weather data cannot be used: a hot week that produces the utility peak demand may be a rainy week for the TMY weather.

2.7.1 Utility Plant Dispatch Order

In order to estimate the emissions reduction potential of a large number of SDHW systems, it is necessary to know the dispatch order of the individual electric power plants under the utility's control. This information is sometimes available but if it isn't, a dispatch order based upon least cost can be generated. Based on the full-capacity average heating rates, the fuel costs, and the variable operating and maintenance costs, the generating costs for each utility plant can be normalized to $/kWh, to determine the least cost dispatch order. Thus, at any utility load, using either the estimated least cost dispatch order or the actual dispatch order, a marginal plant analysis can be performed to predict the emissions resulting from the operation of each DHW system. Much of the necessary data needed to estimate the least cost dispatch order are available from the Federal Energy Regulatory Commission (FERC), from the local regulatory agency, or from the utility itself.

The Wisconsin *Advance Plan 7* power generation information lists three items for each plant that are related to capacity. The *first* is the nominal capacity rating, or maximum possible output of the unit. The *second*, the capacity factor for a particular past year, is the integrated actual MWh over the total possible for the year; i.e., the actual plant output divided by what it could have been the output if it were 100% available. There are two components to the capacity factor: the outages, and the economics of operation. Not only was the plant not used when down for repairs, but it was not used when another source became available at a lower price. A *third* capacity adjustment only accounts for the outages related to availability. Although this information is for a Wisconsin utility, similar information is available for most major US utilities.

While utilities cannot plan for the exact timing of forced outages (e.g., equipment failures), they do know the probability of forced outages based on historical performance. The duration of the scheduled outages (for planned maintenance) is known, but the exact dates of a particular unit being offline for annual maintenance are not listed (or known) in the forecasting documents. By including the forced outage adjusted capacity factor (applied to the nominal capacity of each listed generation unit), the possibility of a forced outage during any day of the year has already been considered in the capacity adjustment.

The *Advance Plan 7* information was converted to maintenance and peak (non-maintenance) periods. Scheduled outages (for maintenance) are not likely to occur during peak periods, but a forced outage, i.e., due to failure, could occur at any time. During scheduled maintenance periods, the added possibility for a forced outage still exists. The maintenance period, accounting for both scheduled and forced outages, is categorized as spring months (March and April) and fall months (September and October), totaling 2928 hours (122 days) of annual operation. The peak period, accounting for forced outages only, is categorized as winter months (January, February, November, and December) and summer months (May, June, July, and August), totaling 5832 hours (243 days) of annual operation.

These two capacity adjustments were applied to the nominal capacities to obtain the peak and maintenance period capacities, with the associated generation cost of each plant. The adjusted capacities for the peak period are shown in Table 2.6.

The different forms of power generation, ordered for least cost, can be placed on a load duration curve with their respective outage adjusted capacities. Fig. 2.17 shows the load duration curve with the least cost ordered generation schedule for the peak period. It follows the basic unit dispatch; nuclear baseload plants first, then coal, and, finally, combustion turbines used for peaking.

2.7.2 Marginal Emission Calculations

Table 2.7 lists the ratings of power plants in Wisconsin for carbon dioxide, sulfur dioxide, nitrous oxide, oxides of nitrogen, methane, and particulates. Both historical and projected emissions were given in the *Advance Plan 7*. Due to the Clean Air Act Amendments of 1990, some changes have occurred. The emission rates shown are the predicted 1994 levels; the 1991 emission rates were much higher. It is assumed that the utilities will follow the optimistic 1994 projected rates. The fossil fuel mix is given with a heating rate, and percentage sulfur and percentage ash, as a method of grading the coal.

The pollution information from Table 2.7 was multiplied by the plant heating rate (Btu/MWh), to obtain the rates of emission in lbs of pollutant per MWh. If a cost is placed on each pollutant in \$/lb, then the environmental impacts of various DHW systems can be quantified and evaluated.

2.7.3 Capacity Contribution Index

Electric utilities value new generation sources not only on their ability to offset operating costs at other plants, but also for their capacity value. Capacity value is the ability for the particular plant to be available (to supply power) when it is most needed. Many methods exist for relating the reliability of different demand-side and supply-side options. The method discussed here is the 'Capacity Contribution Index (CCI)' (Arny and Harsevoort, 1994). The CCI method compares the relative capacity contributions to system reliability of both demand-side and supply-side resources on equal ground.

Table 2.6: Peak Period Forced Outage Adjusted Capacity

Plant Name	Unit (#)	F. O. Adj Capacity (MW)	Fuel & O & M (\$/kWh)	Ranking	Cumulative capacity (MW)
Point Beach	2	487.56	0.0048	1	488
Point Beach	1	487.56	0.0048	2	975
Pleasant Pr.	2	571.34	0.0090	3	1546
Pleasant Pr.	1	571.34	0.0090	4	2118
Edgewater	5	93.16	0.0136	5	2211
Oak Creek	8	300.59	0.0143	6	2512
Oak Creek	7	275.84	0.0143	7	2787
Oak Creek	5	250.46	0.0148	8	3038
Oak Creek	6	252.34	0.0149	9	3290
Presque Isle	4	56.14	0.0162	10	3346
Presque Isle	6	83.71	0.0163	11	3430
Presque Isle	5	82.74	0.0163	12	3513
Presque Isle	1	25.00	0.0165	13	3538
Presque Isle	2	37.00	0.0167	14	3575
Presque Isle	3	57.13	0.0170	15	3632
Port Wash.	2	76.42	0.0199	16	3708
Port Wash.	1	76.42	0.0203	17	3785
Valley	2	59.28	0.0214	18	3844
Valley	4	66.89	0.0216	19	3911
Valley	1	62.45	0.0224	20	3973
Presque Isle	9	82.74	0.0227	21	4056
Presque Isle	8	81.75	0.0227	22	4138
Presque Isle	7	79.77	0.0227	23	4218
Valley	3	67.20	0.0230	24	4285
Port Wash.	3	78.31	0.0237	25	4363
Port Wash.	4	76.37	0.0267	26	4440
Concord	4	82.17	0.0470	27	4522
Concord	3	82.17	0.0470	28	4604
Concord	2	82.17	0.0470	29	4686
Concord	1	82.17	0.0470	30	4768
Oak Creek	9	19.80	0.0557	31	4788
Germantown	4	52.47	0.0600	32	4840
Germantown	3	52.47	0.0600	33	4893
Germantown	2	52.47	0.0600	34	4945
Germantown	1	52.47	0.0600	35	4998
Point Beach	5	19.80	0.0637	36	5018
Port Wash.	6	17.82	0.0651	37	5036

The CCI method replaces peak hour analyses that only provide credit for demand-side options at the system's peak hour. Thus, the CCI method is advantageous from a utility planning perspective, especially when renewable options are being evaluated. The capacity value of a particular option is

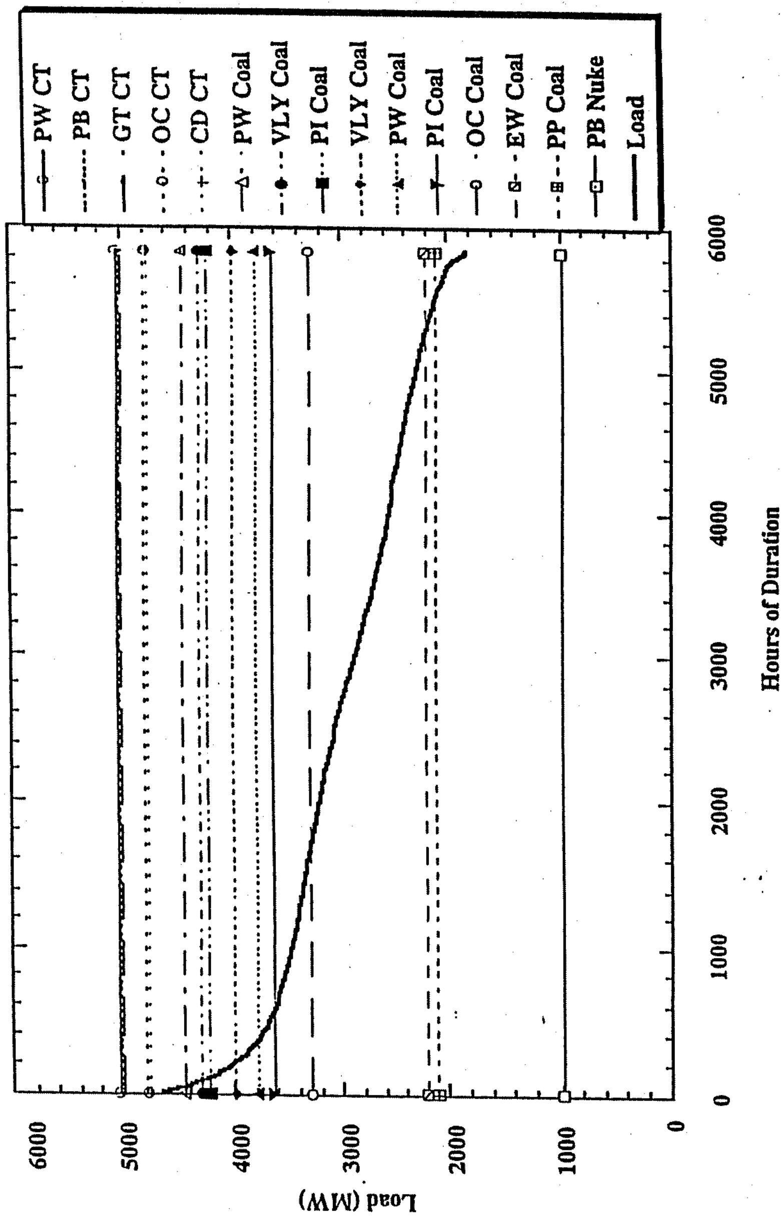

Figure 2.17: Wepco peak period load duration curve showing the electric plants needed to meet the load.

Table 2.7: WEPCO 1994 Rates of Discharge of Significant Pollutants/Fossil Fuel Units

Plant Name	Unit (#)	Capacity (MW)	CO_2	SO_2	N_2O (lb/MBtu)	NO_x	CH_4	Partic-ulates	Total ash	HHV* Btu/lb	Sulfur %	Ash %
Oak Creek	8	305	204	0.83	0.0018	0.28	0.0011	0.02	10.08	12400	0.53	12.50
	7	280	204	0.83	0.0018	0.28	0.0011	0.02	10.08	12400	0.53	12.50
	6	260	204	0.83	0.0018	0.28	0.0011	0.02	10.08	12400	0.53	12.50
	5	258	204	0.83	0.0018	0.28	0.0011	0.02	10.08	12400	0.53	12.50
Port Wash.	4	80	208	2.24	0.0015	0.36	0.0159	0.04	4.91	13250	1.53	6.50
	3	82	208	2.24	0.0015	0.36	0.0159	0.04	4.91	13250	1.53	6.50
	2	80	208	2.24	0.0015	0.36	0.0159	0.04	4.91	13250	1.53	6.50
	1	80	208	2.24	0.0015	0.36	0.0159	0.04	4.91	13250	1.53	6.50
Valley	2	137	208	2.27	0.0019	0.50	0.0011	0.05	4.91	13250	1.59	6.50
	1	130	208	2.27	0.0019	0.50	0.0011	0.05	4.91	13250	1.59	6.50
Pleasant Pr	2	580	214	0.75	0.0017	0.40	0.0013	0.01	5.95	8400	0.36	5.00
	1	580	214	0.75	0.0017	0.40	0.0013	0.01	5.95	8400	0.36	5.00
Presque Is.	9	84	208	1.09	0.0015	0.70	0.0012	0.02	7.50	8800	0.52	6.60
	8	83	208	1.09	0.0015	0.70	0.0012	0.02	7.50	8800	0.52	6.60
	7	85	208	1.09	0.0015	0.70	0.0012	0.02	7.50	8800	0.52	6.60
	6	87	211	1.56	0.0015	0.84	0.0011	0.04	6.56	12950	0.77	8.50
	5	84	211	1.56	0.0015	0.84	0.0011	0.03	6.56	12950	0.77	8.50
	4	57	211	1.56	0.0015	0.61	0.0011	0.04	6.56	12950	0.77	8.50
	3	58	211	1.56	0.0015	0.61	0.0011	0.03	6.56	12950	0.77	8.50
	2	37	211	1.56	0.0015	0.84	0.0011	0.09	6.56	12950	0.77	8.50
	1	25	211	1.20	0.0015	0.84	0.0011	0.02	6.56	12950	0.77	8.50
General CT	1	50	206	2.60	0.0100	0.85	0.0000	0.05	7.00	11700	1.85	9.10
Concord	4	83	125	0.00	0.0140	0.09	0.0003	0.00	0.00	21100	0.00	0.00
	3	83	125	0.00	0.0140	0.09	0.0003	0.00	0.00	21100	0.00	0.00
	2	83	125	0.00	0.0140	0.09	0.0003	0.00	0.00	21100	0.00	0.00
	1	83	125	0.00	0.0140	0.09	0.0003	0.00	0.00	21100	0.00	0.00

*HHV is the higher heating value

the value of having the equipment around and ready to use to meet demand on a peak day, even if it is not actually used. An alternate explanation of the CCI method is that it compares the cost of the customer not being served to the cost of having the capacity to always meet the load. There is an added value to options that can dependably contribute energy or reduce load during peak periods.

Most cost analysis schemes for comparing demand side management options compare only peak hour or peak day demand reduction. There are values for energy, demand and emission reduction, but there is an additional value for reliable capacity on the peak day. The capacity value is based on the probability of meeting the utility peak demand when it occurs. There is a value placed on the coincident availability with the peak utility demand. Thus, capacity value is time-of-day dependent. For most utility load forecasting analyses, twenty different peak days are required to test the reliability of a system.

The peak load periods during the year are given a CCI value that relates the value of the capacity needed during that hour relative to the capacity that was needed at all other periods during the year (Arny and Harsevoort,

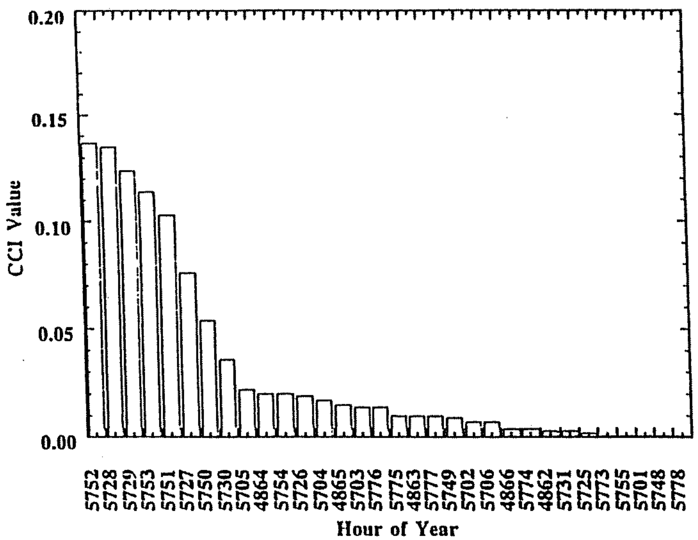

Figure 2.18: Capacity Contribution Index (CCI) values of 1991

1994). The CCI values for each hour of the year sum to equal one. There is an added value to options that can reliably contribute energy or reduce load on peak days like a combustion turbine, its "peak clipping" competitor. A gas combustion turbine has nearly a 100% availability since it is able to operate at its rated capacity whenever needed (except for forced outages). The solar system, depending on its availability during the listed peak periods is given a relative value (availability credit) in comparison to the combustion turbine.

Thus, the CCI values consider the probability of all power plant outages in the state at all hours of the year. Hours of peak state utility demand are valued highest. Values where the system has excess capacity are valued at zero. The CCI method distributes the value of meeting capacity over the twenty to forty hours. This method is much more predictive of each power plant's reliable contribution to capacity then analyses that consider only one peak hour of the year. The 1991 CCI values for the state of Wisconsin utility system are shown in Fig. 2.18. Hour 5,752, one of the hot sunny afternoons in August, had the highest CCI in 1991. Available capacity during those peak load hours was valued highest since that was when the Wisconsin utility system needed the capacity most. Thus, the solar contribution to capacity during that hour of the year has the most value compared to all other hours of the year.

2.7.4 Utility Cost Analysis

Utilities usually view solar domestic hot water systems as energy saving devices. Yet, since solar DHW systems provide energy, a large number of them could be considered a 'diversified solar thermal power plant'. Analyzing solar DHW systems from a supply-side perspective gives the solar DHW systems credit for providing energy and capacity, while reducing utility demand, emissions and revenue. How does solar stack up against other options when initial costs, fuel costs, capacity value and other factors are included? To properly analyze the benefits of solar, the marginal cost perspective needs to be supplemented with a lifetime cost analysis (which includes initial and O&M costs). For this analysis, the life cycle cost (LCC) of the solar DHW systems, including the value of contribution to meet the peak referenced to a combustion turbine (the last unit added) and all remaining costs need to be normalized (divided by the energy use) for a fair comparison. As defined by the Wisconsin Center for Demand-Side Research:

> "A levelized cost represents both initial capital costs and annual operation and maintenance costs as an equal stream of annual cash flows over a life of a measure. Levelized costs allow measures with different lifetimes to be compared" (WCDSR, 1994).

Advance Plan 7, D24: Power Supply, uses a busbar cost comparison study to screen supply-side technologies. The busbar cost of electrical energy levelizes the cost of different power plants to a cost per unit of electricity produced ($/kWh). Busbar analysis is performed at the generator of electricity. A more inclusive version of a busbar cost analysis is the 'Customer Meter' real levelized cost of delivered energy, which includes transmission and distribution losses as well as the capacity value referenced to a combustion turbine.

Through levelized cost analysis, the capacity value of the diversified solar plant (many solar DHW systems) is elucidated. The life cycle costs of each new technology are compared to the LCC of each solar DHW system. Each LCC is divided by the amount of energy delivered to obtain the cost per unit of electricity. The real levelized cost calculation can be performed with or without emission monetization.

2.7.5 Customer Cost Analysis

For the customer perspective cost analysis, the solar DHW systems are assumed to be purchased by the utility and paid for by the customer over the system's life. The most significant barriers to customer purchases of SDHW systems are high initial costs and technological uncertainty. Utility involvement in a large-scale SDHW program can circumvent both problems. Utilities have been giving rebates for energy savings options such as compact light bulbs for many years. Some utilities are also giving credit for peak demand reduction and avoided energy costs. A utility rebate coupled with a financing program in which the cost of the solar system is added to monthly bills in installments brings the perceived high cost of solar DHW systems to a reasonable level. Also, the utility involvement and the large number of system installed throughout the community help appease customer uncertainties about reliability.

From the customer's view point, the life cycle savings of a solar DHW system is calculated as the difference between the present value of the fuel saved and the present value of owning, operating and maintaining the system (Duffie and Beckman, 1991). The life cycle savings is often negative when the customer purchases the system on the open market, pays normal rates for the electricity used, and receives no return for demand and pollution reduction. The customer savings picture can be improved if the utility contributes to the purchase through a rebate program.

Determination of an appropriate utility rebate is based on avoided generation costs, including peak demand reduction and pollution reduction. The Wisconsin Center for Demand Side Research defines avoided costs as:

> "Avoided costs are those costs that a utility can avoid if it is able to procure capacity and energy from a source other than conventional utility-owned and operated facilities, or if the utility doesn't have to meet an electric demand at all." (WCDSR, 1994)

The avoided costs provided by the WCDSR are given in Table 2.8. WCDSR considers the values in the table, the avoided energy costs at the generator, and the avoided capacity costs for generation. The avoided costs for demand include reductions in investment in new electric transmission and distribution facilities. In the following results, the emissions were calculated for all hours of the year; therefore the emissions values in Table 2.8 are for reference purposes only.

2.8 Results

Variations of three differently sized solar systems were compared with a typical electric DHW system (52 gallons, 4.5 kW electrical resistance heating elements with an energy factor of 0.87). Three collector area/storage tank size combinations were considered for both one and two tank systems. Systems used either a 30 W pump or a photovoltaic pump. All DHW system parameters are listed in Table 2.9.

2.8.1 Annual Energy Savings

The energy savings from various solar DHW system sizes was estimated with TRNSYS. The TRNSYS simulation used the measured 1991 hourly

Table 2.8: Avoided Cost Values Used by WCDSR (1994)*

Time Period	Avoided Costs (w/ SO_2 Emissions)	Avoided Costs (w/ SO_2 & Greenhouse Gas)
Summer Peak Demand	72.97 $/kW-yr	72.97 $/kW-yr
Summer: on-peak	2.772 cents/kWh	4.471 cents/kWh
Summer: off-peak	1.767 cents/kWh	3.388 cents/kWh
Winter: on-peak	3.129 cents/kWh	4.796 cents/kWh
Winter: off-peak	2.187 cents/kWh	3.792 cents/kWh
Spring/Fall: on-peak	2.803 cents/kWh	4.420 cents/kWh
Spring/Fall: off-peak	1.937 cents/kWh	3.556 cents/kWh

*On-peak means 9 a.m. to 9 p.m. during weekdays.

weather data, monthly water mains temperatures, and the WATSIM derived weekday and weekend water draw profiles. Annual solar energy contribution is often expressed in terms of a solar fraction, the percentage of the conventional energy requirements that were met by the solar system.

Annual electrical energy requirements for the twelve solar DHW systems and the conventional electric DHW system are compared in Fig. 2.19. As expected, the variations of System 3, with the largest collector areas, have the least annual energy requirements. The interesting difference between system performances comes not from the system size, but from the variations of SDHW system components. The 30 W electric pump adds an additional 83 kWh of energy per year per system in comparison to a PV pump. The two-tank models fared worse than the single-tank models, due to constant losses in the electrically heated back-up tank. Energy (heat) losses from the back-up tank were made up by the zip heater. The added electrical requirements of the two-tank system represent a worse case scenario energy usage due to standby heat losses. In a real system, some amount of heat from the solar tank would compensate for a portion of the losses. Therefore, the results for the two-tank model represent an upper limit to energy and demand requirements of those systems.

The energy requirements for conventional DHW systems vary according to the seasonal mains water temperatures. The monthly variance of solar DHW system performance is also due to changing mains temperatures, but is more dependent on solar radiation and ambient temperature. The monthly energy requirements 'best' (case 12) and 'worst' (case 1) solar DHW systems

Table 2.9: DHW Characteristics

DHW System			Characteristics					
			Collector Area		Solar Storage Tank Size		Back-up Tank	
Tank Set-up	Case	Pump	ft^2	m^2	gal	ℓ	gal	ℓ
Conventional 4.5 kW Electric	0	none	x	x	x	x	52	196.8
Solar 1, 2 Tanks	1	30W	43.06	4	55	208.2	52	196.8
Solar 1, 2 Tanks	2	PV	43.06	4	55	208.2	52	196.8
Solar 1B, 1 Tank	3	30W	43.06	4	55	208.2	x	x
Solar 1B, 1 Tank	4	PV	43.06	4	55	208.2	x	x
Solar 2, 2 Tanks	5	30W	64.58	6	80	302.8	52	196.8
Solar 2, 2 Tanks	6	PV	64.58	6	80	302.8	52	196.8
Solar 2B, 1 Tank	7	30W	64.58	6	80	302.8	x	x
Solar 2B, 1 Tank	8	PV	64.58	6	80	302.8	x	x
Solar 3, 2 Tanks	9	30W	96.88	9	120	454.2	52	196.8
Solar 3, 2 Tanks	10	PV	96.88	9	120	454.2	52	196.8
Solar 3B, 1 Tank	11	30W	96.88	9	120	454.2	x	x
Solar 3B, 1 Tank	12	PV	96.88	9	120	454.2	x	x

from Table 2.9 are compared with the conventional electric DHW systems in Fig. 2.20.

During the annual simulations the utility load is known and the plant at the margin can be found from the dispatch order shown in Table 2.6. The gas combustion turbines were operated (and thus at the margin) 497 hours, peaking coal plants (Coal 3) were at the margin for 3735 hours, intermediate coal plants (Coal 2) were at the margin for 3951 hours, and base load coal plants (Coal 1) were at the margin for only 577 hours. The impacts of the best and worst solar DHW systems (from an energy savings standpoint) are compared with the conventional electric system in Fig. 2.21. An interesting combination of plants at the margin, in conjunction with the timing of DHW demands can be seen. Solar systems provide significant energy savings during all types of marginal plant operation, except base coal and nuclear plants.

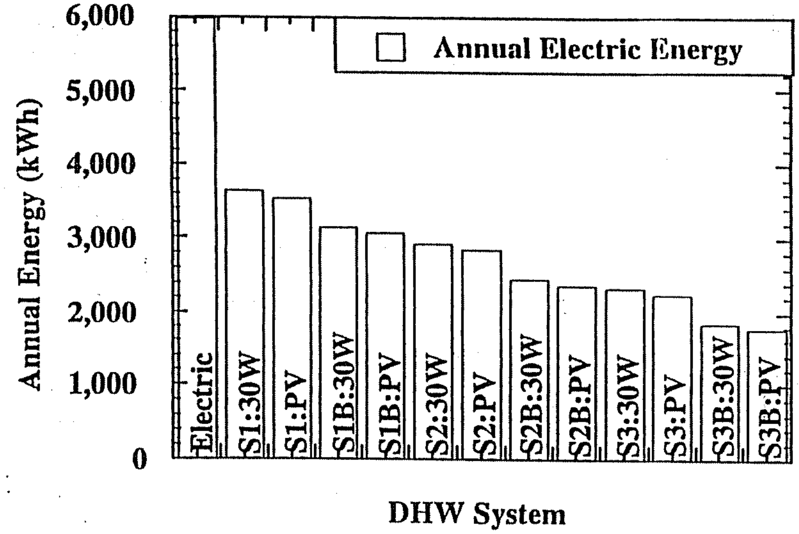

Figure 2.19: 1991 Annual electricity requirements for various DHW systems

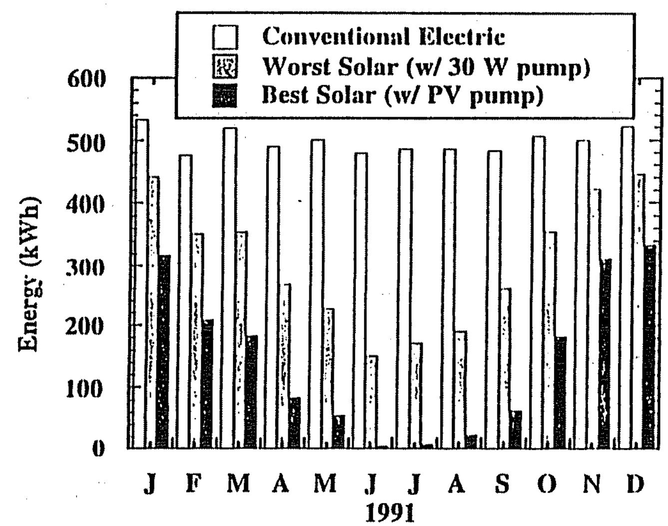

Figure 2.20: 1991 Monthly energy requirements for various DHW systems

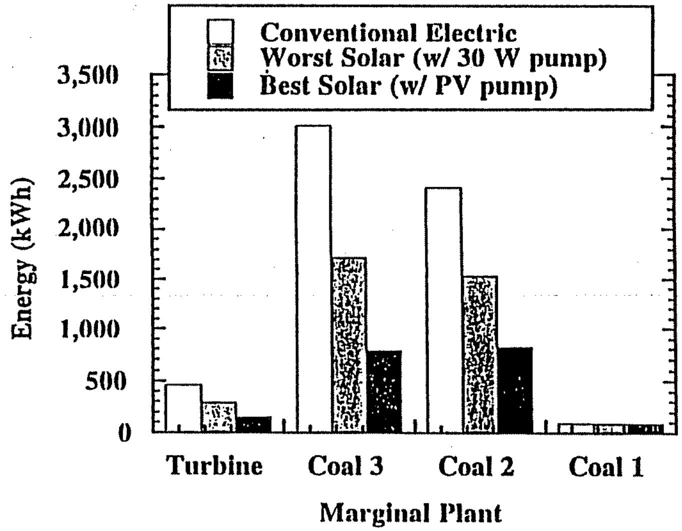

Figure 2.21: 1991 WEPCO annual energy reduction of marginal plant operation

2.8.2 Peak Hour Demand Reduction

Solar system peak performance coincides with utility peak demand, which occurs in the afternoon on the second or third day of hot sunny weather. The contribution of a conventional electric DHW system to peak utility demand is shown in Table 2.10 where the solar system demand (from auxiliary heating) at the peak utility demand hour are compared against the conventional system.

The order of the systems in Table 2.10 is by decreasing energy savings, the order shown in Fig. 2.19. The rankings for peak utility demand reduction is not in the same (inverse) order as the energy savings for each solar system. The systems with the highest demand reduction are the one-tank systems with PV pumps. The one-tank systems with 30 W pumps have the next largest peak demand reduction. Even the two-tank systems with PV pumps had higher peak demands than the one-tank systems with 30 watt pumps. Thus, electrical demand from the constant losses from the electric back-up tanks exceed the electric pump demand. Additionally, if the tanks are inside, the losses add heat to the house which put a larger load on electric air conditioners in the summer. Tank configuration appears to be more important than parasitic power. Again, the two-tank configuration provides an upper limit for solar system demand due to the zip heater model with constant losses.

Table 2.10: Peak Utility Demand of DHW Systems

WEPCO Peak Demand 4641 MW DHW System	Peak Demand (2 p.m. August 29th, 1991) (kW)	(Rank)
Conventional Electric (4.5 kW)	0.660	*
Solar 1 (2 Tanks) 30 W pump	0.195	12
Solar 1 (2 Tanks) PV pump	0.165	11
Solar 1B (1 Tank) 30 W pump	0.083	8
Solar 1B (1 Tank) PV pump	0.053	5
Solar 2 (2 Tanks) 30 W pump	0.097	9
Solar 2 (2 Tanks) PV pump	0.067	6
Solar 2B (1 Tank) 30 W pump	0.030	3
Solar 2B (1 Tank) PV pump	0.000	1
Solar 3 (2 Tanks) 30 W pump	0.097	9
Solar 3 (2 Tanks) PV pump	0.067	6
Solar 3B (1 Tank) 30 W pump	0.030	3
Solar 3B (1 Tank) PV pump	0.000	1

Fig. 2.22 shows the WEPCO load for the peak day along with the contribution to the load of conventional electric DHW systems and the "best" and "worst" solar systems. The best solar system does not contribute to the utility load at any time during the peak day.

2.8.3 Annual and Monthly Emission Savings

While the societal costs for various pollutants are a subject of debate, the actual amounts of pollutants avoided by replacing DHW systems with SDHW systems are only dependent on characteristics of the marginal power plant. Based on the operation of each WEPCO plant, the annual results in Table 2.11 show the amount of each measured pollutant produced by the various marginal plants to meet the electric requirements of each system. From a marginal emission approach, the average conventional system operation produces nearly six and one half tons of airborne pollutants. Based on the 'best' (case 12) and 'worst' (case 1) from an energy saving standpoint, solar DHW systems save annually 4.5 tons and 2.5 tons of

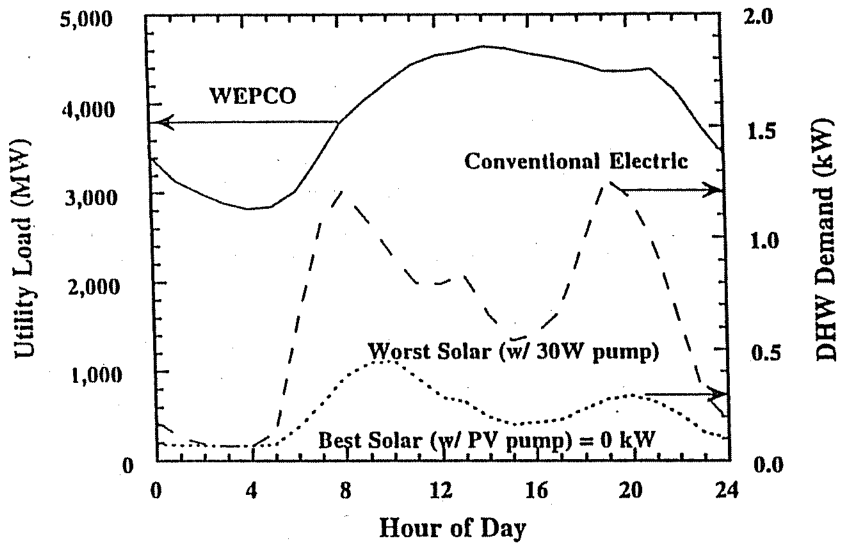

Figure 2.22: DHW demand comparison, WEPCO peak day (Thursday, August 29, 1991)

pollutants (respectively) when compared to the conventional electric DHW system.

The monthly emissions from the operation of a conventional electric DHW system and the 'best' and 'worst' SDHW systems for the six pollutants are compared in Fig. 2.23 through Fig. 2.28. For the conventional electric DHW system, the monthly emissions of carbon dioxide, oxides of nitrogen, and particulates are relatively constant from month to month, while sulfur dioxide, nitrogen oxide, and methane show some dramatic monthly fluctuations. The utility maintenance months (March, April, September and October) represent the worst case scenario for sulfur dioxide, nitrous oxide, and methane emissions for the average conventional electric DHW system. The notable increase in those three pollutants during utility maintenance months is due to a combination of scheduled outages of some baseload plants and lower utility loads which result in "dirtier" intermediate coal plants at the margin.

Traditionally, SDHW systems are only given credit for reducing annual energy requirements and possibly peak summer demand. By looking at solar on an annual basis (with hourly utility load data, real power plant information, and realistic scheduling information), the benefits of solar DHW systems emission reductions can be quantized.

Table 2.11: 1991 WEPCO Annual Emissions for Various Electric DHW Options

DHW Systems			Annual Environmental Impact					
			CO_2	SO_2	N_2O	NO_X	CH_4	TSP
Tank Set-up	Case	Pump	lb	lb	lb	lb	lb	lb
Conventional Electric	0	Elec	12705	80.78	0.180	28.35	0.200	1.820
Solar 1 - 2 Tanks	1	30W	7687	47.37	0.109	17.08	0.111	1.084
Solar 1 - 2 Tanks	2	PV	7468	46.23	0.108	16.54	0.111	1.053
Solar 1B - 1 Tank	3	30W	6638	41.18	0.098	14.75	0.100	0.940
Solar 1B - 1 Tank	4	PV	6457	39.98	0.095	14.35	0.096	0.913
Solar 2- 2 Tanks	5	30W	6150	37.47	0.089	13.58	0.087	0.858
Solar 2- 2 Tanks	6	PV	5971	36.28	0.087	13.18	0.083	0.831
Solar 2B - 1 Tank	7	30W	5159	31.42	0.078	11.44	0.074	0.721
Solar 2B - 1 Tank	8	PV	4978	30.22	0.075	11.00	0.071	0.694
Solar 3 - 2 Tanks	9	30W	4899	29.29	0.070	10.81	0.063	0.677
Solar 3 - 2 Tanks	10	PV	4730	28.17	0.067	10.44	0.060	0.653
Solar 3B - 1 Tank	11	30W	3893	23.12	0.058	8.63	0.051	0.537
Solar 3B - 1 Tank	12	PV	3720	21.98	0.055	8.25	0.047	0.512

2.8.4 Utility Savings

The customer-meter real levelized cost analysis is the more inclusive busbar cost of electricity that includes the costs of transmission and distribution losses. The many solar DHW systems were treated as a 'diversified solar plant'. The nominal capacities of the diversified solar DHW plants were considered to be the demand reductions at the peak electric DHW demands (not the utility peak). Cost analyses were done using the utility peak hour DHW demand reduction. Included in the SDHW cost analysis are utility purchase and installation, the transmission and distribution losses (6% for WEPCO) of the new technologies (none for the diversified solar plants), and the fixed and variable costs of all operations. Each technology, including the solar DHW systems, is given credit for contribution to capacity, referenced to a 99.4% available combustion turbine.

The cost analysis compares the utility cost (in \$/year and \$/kWh) for each power plant. The cost perspective evaluates all utility costs associated with the purchase and operation of the best available technology for electric power production. Two baseload plants, two intermediate load plants, and one peaking combustion turbine were chosen for comparison with the

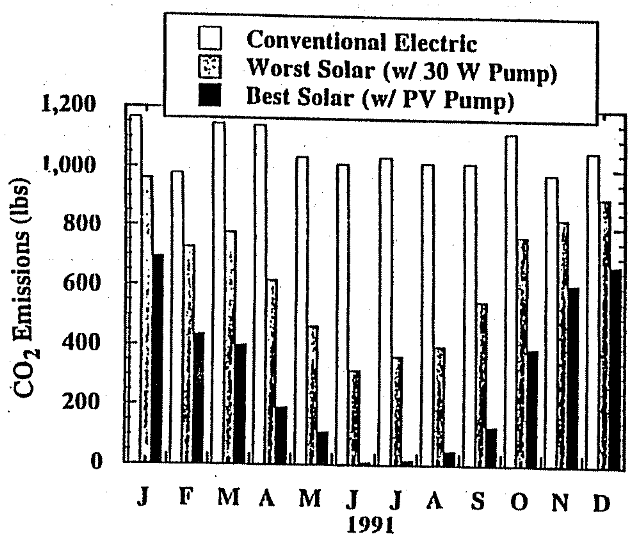

Figure 2.23: 1991 WEPCO carbon dioxide monthly emissions

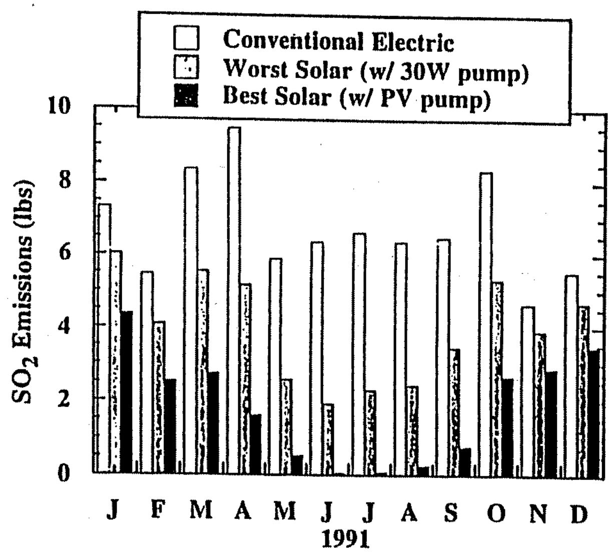

Figure 2.24: 1991 WEPCO sulfur dioxide monthly emissions

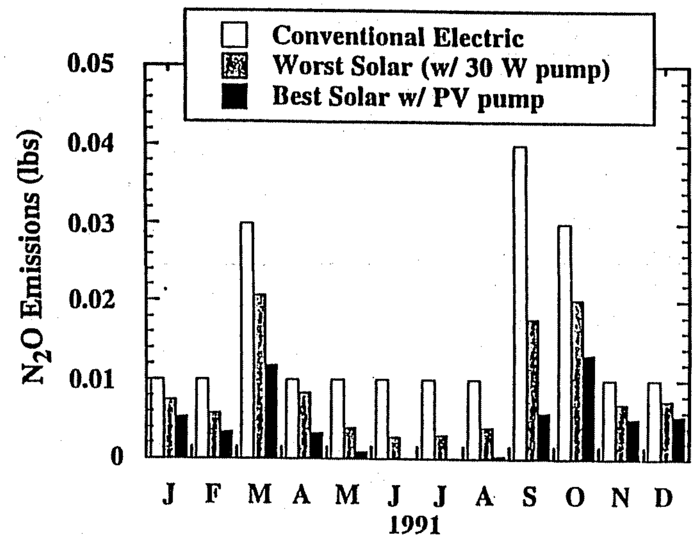

Figure 2.25: 1991 WEPCO nitrous oxide monthly emissions

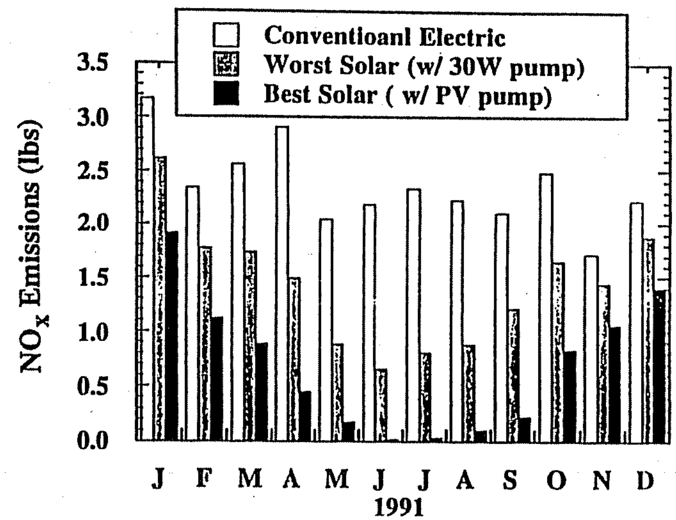

Figure 2.26: 1991 WEPCO oxides of nitrogen monthly emissions

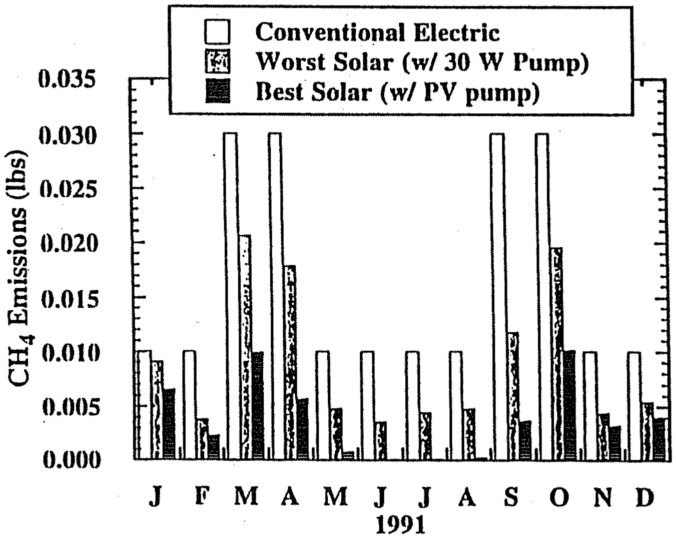

Figure 2.27: 1991 WEPCO methane monthly emissions

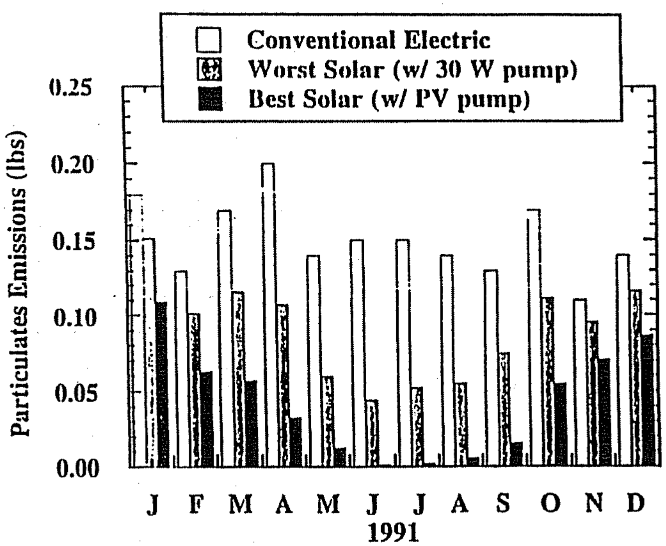

Figure 2.28: 1991 WEPCO particulates monthly emissions

'diversified solar plant' (all plant information was obtained from the Public Service Commission of Wisconsin). All new technologies were considered to operate at the EPA New Source Performance Standards for emission production. The costs per unit of energy produced (\$/kWh) of the new technologies were compared (with zero emission monetization) to the solar DHW values considering zero credit for solar emission reductions, and credit for PSCW value actual solar emission savings, and high value actual solar emissions savings (as discussed in Sec. 2.8.3). The various levelized costs are shown Table 2.12. The lifetime for solar systems was 15 years, while new technology lifetimes were 30 years. Solar systems were given maintenance costs of \$25/year based on a maintenance check every 2-3 years.

The first unit electricity cost result (7^{th} column, Table 2.12) does not penalize the new technologies for their emissions, neither does it give credit to the 'diversified solar plants' for their emission reductions. The second and third listed unit electricity costs (8^{th} and 9^{th} columns of Table 2.12) consider the unit cost of the new technologies without monetization, yet give the 'diversified solar systems' the emission savings that they actually incurred with the marginal emissions reduction analysis based on the least cost production model discussed in Sec. 2.7.1. The solar credits were given for the PSCW and high emission monetization values from Table 2.1A.

Five of solar DHW systems 'provide energy' at a cost to the utility that is less than the associated cost for a new technology combustion turbine (\$0.06/kWh) even without credit for emission reduction. When the diversified solar systems are given credit for their emission reductions (at the Public Service Commission of Wisconsin monetization levels), all but one of the solar systems are competitive with the a new gas combustion turbine, five SDHW systems are less expensive than an intermediate coal plant, with two solar systems less expensive than the baseload plants! When the highest published emission monetization values are used to credit the solar systems, all of the solar systems are significantly less expensive than the baseload plants, and six SDHW systems actually "save" the utility money per each kWh produced over its lifetime.

2.8.5 Customer Savings

A monthly customer bill impact analysis was performed for each of the twelve solar DHW system variations. The cost analysis was made under the assumption that the utility purchases the solar systems for the customers and the customers pay back the utilities for the systems through their monthly electric bills over the course of the systems' lifetime (fifteen years). The customer utility bill impact analysis demonstrates the positive or negative cash flow that the customers would see in their monthly statements.

Table 2.12: Customer-Meter Unit Cost of Electricity

Plant Technology	Nominal Capacity	Plant Type	Capitol Cost	CCI Values	Total Costs Zero Ext.	Total w/ Zero	Total w/ PSCW	Total w/ High
	MW		$/kW	%	$/yr	$/kWh	$/kWh	$/kWh
Adv Nuclear	600	Base	1609	0.994	3.12E+08	0.032	x	x
IGCC	400	Base	1567	0.994	2.22E+08	0.036	x	x
Combined Cycle	200	Int.	694	0.994	1.29E+08	0.046	x	x
HAT Cycle	200	Int.	694	0.994	1.21E+08	0.041	x	x
WISC CT	83	Peak	323	0.994	6.41E+07	0.060	x	x
Solar 1 30W	0.000238	Renew.	2000	0.829	225.57	0.072	0.052	0.006
Solar 1 PV	0.000238	Renew.	2500	0.875	275.37	0.089	0.070	0.024
Solar 1B 30W	0.000202	Renew.	1800	0.946	205.65	0.055	0.036	-0.010
Solar 1B PV	0.000202	Renew.	2300	0.991	255.45	0.071	0.051	0.006
Solar 2 30W	0.000392	Renew.	2300	0.846	255.45	0.052	0.033	-0.013
Solar 2 PV	0.000392	Renew.	2800	0.885	305.25	0.067	0.047	0.001
Solar 2B 30W	0.000364	Renew.	2100	0.955	235.53	0.042	0.022	-0.023
Solar 2B PV	0.000364	Renew.	2600	0.994	285.33	0.055	0.035	-0.011
Solar 3 30W	0.000561	Renew.	3500	0.851	374.97	0.066	0.046	0.000
Solar 3 PV	0.000576	Renew.	4000	0.885	424.77	0.077	0.057	0.011
Solar 3B 30W	0.000561	Renew.	3200	0.96	345.09	0.051	0.031	-0.014
Solar 3B PV	0.000561	Renew.	3800	0.994	404.85	0.064	0.044	-0.001

Many scenarios for possible utility rebates based on avoided generation costs, peak demand reduction, and emission monetization were considered as shown in Table 2.13.

Since the choice of economic parameters highly influences the lifetime benefits and costs of DSM programs, the conservative PSCW parameters were used for a 'base case', as shown in Table 2.14.

The results for the twelve solar DHW systems are shown in Table 2.15 for the base case (with no utility incentive) and three rebate scenarios, where a positive monthly bill impact ($/month) represents a reduction in the customer electricity bill, and a negative monthly bill impact represents an

Table 2.13: Values for Solar System Costs and Savings

Solar System	System Cost	Energy Saved	Demand Reduction	Avoided Generation	PSCW Pollution	High Pollution
System	$	kWh	kW	$/yr	$/yr	$/yr
SYS1: 30W	2000	1955	0.465	47.88	43.52	145.48
SYS1:PV	2500	2061	0.495	49.33	45.38	151.68
SYS1B:30W	1800	2453	0.577	56.40	52.52	174.95
SYS1B:PV	2300	2538	0.607	58.22	54.09	180.16
SYS2: 30W	2300	2674	0.563	61.73	56.81	189.87
SYS2:PV	2800	2758	0.593	63.53	58.36	195.04
SYS2B:30W	2100	3142	0.630	70.08	65.33	217.70
SYS2B:PV	2600	3227	0.660	71.90	66.90	222.90
SYS3: 30W	3500	3260	0.563	74.12	67.64	225.82
SYS3:PV	4000	3340	0.593	75.84	69.11	230.69
SYS3B:30W	3200	3735	0.630	82.46	76.30	254.13
SYS3B:PV	3700	3816	0.660	84.21	77.80	259.09

Table 2.14: Base Case Economic Parameters

Parameter	Value
System Lifetime	15 years
Fuel Inflation Rate	3 %
Annual Maintenance	25 $/year
Discount Rate	5.5 %
Customer Electricity Cost	0.08 $/kWh

increase in the customer electricity bill. Without any rebates, four one-tank systems provide the customer with a positive monthly cash flow. With a utility rebate for demand reduction ($72.93/kW-yr from WCDSR), eight of the twelve solar DHW systems provide positive customer electric bill impacts. The two two-tank systems with PV pumps had negative monthly bill impacts even with a modest rebate.

Table 2.12: Customer-Meter Unit Cost of Electricity

Plant Technology	Nominal Capacity	Plant Type	Capitol Cost	CCI Values	Total Costs Zero Ext.	Total w/ Zero	Total w/ PSCW	Total w/ High
	MW		$/kW	%	$/yr	$/kWh	$/kWh	$/kWh
Adv Nuclear	600	Base	1609	0.994	3.12E+08	0.032	x	x
IGCC	400	Base	1567	0.994	2.22E+08	0.036	x	x
Combined Cycle	200	Int.	694	0.994	1.29E+08	0.046	x	x
HAT Cycle	200	Int.	694	0.994	1.21E+08	0.041	x	x
WISC CT	83	Peak	323	0.994	6.41E+07	0.060	x	x
Solar 1 30W	0.000238	Renew.	2000	0.829	225.57	0.072	0.052	0.006
Solar 1 PV	0.000238	Renew.	2500	0.875	275.37	0.089	0.070	0.024
Solar 1B 30W	0.000202	Renew.	1800	0.946	205.65	0.055	0.036	-0.010
Solar 1B PV	0.000202	Renew.	2300	0.991	255.45	0.071	0.051	0.006
Solar 2 30W	0.000392	Renew.	2300	0.846	255.45	0.052	0.033	-0.013
Solar 2 PV	0.000392	Renew.	2800	0.885	305.25	0.067	0.047	0.001
Solar 2B 30W	0.000364	Renew.	2100	0.955	235.53	0.042	0.022	-0.023
Solar 2B PV	0.000364	Renew.	2600	0.994	285.33	0.055	0.035	-0.011
Solar 3 30W	0.000561	Renew.	3500	0.851	374.97	0.066	0.046	0.000
Solar 3 PV	0.000576	Renew.	4000	0.885	424.77	0.077	0.057	0.011
Solar 3B 30W	0.000561	Renew.	3200	0.96	345.09	0.051	0.031	-0.014
Solar 3B PV	0.000561	Renew.	3800	0.994	404.85	0.064	0.044	-0.001

Many scenarios for possible utility rebates based on avoided generation costs, peak demand reduction, and emission monetization were considered as shown in Table 2.13.

Since the choice of economic parameters highly influences the lifetime benefits and costs of DSM programs, the conservative PSCW parameters were used for a 'base case', as shown in Table 2.14.

The results for the twelve solar DHW systems are shown in Table 2.15 for the base case (with no utility incentive) and three rebate scenarios, where a positive monthly bill impact ($/month) represents a reduction in the customer electricity bill, and a negative monthly bill impact represents an increase in the customer electricity bill. Without any rebates, four one-tank systems provide the customer with a positive monthly cash flow. With a utility rebate for demand reduction ($72.93/kW-yr from WCDSR), eight of the twelve solar DHW systems provide positive customer electric bill impacts. The two two-tank systems with PV pumps had negative monthly bill impacts even with a modest rebate.

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	$	kWh	kW	$/yr	$/yr	$/yr
SYS1: 30W	2000	1955	0.465	47.88	43.52	145.48
SYS1:PV	2500	2061	0.495	49.33	45.38	151.68
SYS1B:30W	1800	2453	0.577	56.40	52.52	174.95
SYS1B:PV	2300	2538	0.607	58.22	54.09	180.16
SYS2: 30W	2300	2674	0.563	61.73	56.81	189.87
SYS2:PV	2800	2758	0.593	63.53	58.36	195.04
SYS2B:30W	2100	3142	0.630	70.08	65.33	217.70
SYS2B:PV	2600	3227	0.660	71.90	66.90	222.90
SYS3: 30W	3500	3260	0.563	74.12	67.64	225.82
SYS3:PV	4000	3340	0.593	75.84	69.11	230.69
SYS3B:30W	3200	3735	0.630	82.46	76.30	254.13
SYS3B:PV	3700	3816	0.660	84.21	77.80	259.09

Table 2.14: Base Case Economic Parameters

Parameter	Value
System Lifetime	15 years
Fuel Inflation Rate	3 %
Annual Maintenance	25 $/year
Discount Rate	5.5 %
Customer Electricity Cost	0.08 $/kWh

Table 2.15: Customer Monthly Bill Savings in $/month.

	System Cost	Energy saved	Demand Sav.	Base Case	Demand Rebate	Avoided Gen.	Emission Credit PSCW	Emission Credit High	Average Savings
System	$	kWh	kW	$/mo.	$/kW-yr	$/yr	$/yr	$/yr	$/month
SYS2B:30W	2100	3142	0.630	5.28	9.89	12.31	11.83	27.12	13.29
SYS2B:PV	2600	3227	0.660	1.81	6.64	9.03	8.52	24.17	10.04
SYS3B:30W	3200	3735	0.630	0.91	5.52	9.18	8.56	26.40	10.11
SYS1B:30W	1800	2453	0.577	2.24	6.46	7.90	7.51	19.79	8.78
SYS2: 30W	2300	2674	0.563	-0.14	3.98	6.05	5.56	18.91	6.87
SYS3B:PV	3700	3816	0.660	-2.60	2.24	5.85	5.21	23.40	6.82
SYS1B:PV	2300	2538	0.607	-1.23	3.21	4.61	4.20	16.85	5.53
SYS2:PV	2800	2758	0.593	-3.62	0.73	2.76	2.24	15.95	3.61
SYS3: 30W	3500	3260	0.563	-5.40	-1.28	2.04	1.39	17.26	2.80
SYS1: 30W	2000	1955	0.465	-3.42	-0.02	1.38	0.95	11.18	2.01
SYS1:PV	2500	2061	0.495	-6.72	-3.10	-1.77	-2.17	8.50	-1.05
SYS3:PV	4000	3340	0.593	-8.91	-4.57	-1.30	-1.97	14.24	-0.50

When multiple utility rebates for peak demand reduction (D in Table 2.16), avoided generation costs (G), and emission reductions (E) were given, all SDHW systems provided positive monthly cash flows for the customer, as shown in Table 2.16.

Unlike the relationship between collector area-tank size ratio and energy savings, there is no straightforward correlation for customer bill savings. The single-tank systems (designated 'B') provide greater savings than their equivalent two-tank models. The slightly higher peak demand reduction rebates, avoided generation rebates, and emissions credits for PV pumped systems (compared to those of the 30 W systems of equivalent size and tank configuration) did not outweigh the increased initial costs, due to their more expensive PV pumps ($500 more per system). The least expensive systems do not necessarily save the most money. The systems with the most energy savings are not more cost effective than other SDHW systems, and are often less so.

2.9 Conclusions

Using an average hot water draw profile (derived from WATSIM), an energy rate controlled zip heater can effectively represent diversified electric demand in both conventional and solar DHW systems. Zip heater modeling (with the average hot water draw profile) eliminates the need for simulations using a large number of representative individual customer hot water draw profiles. For two-tank solar DHW system configurations, the auxiliary energy requirements represent an upper limit to system energy demands due to the addition of a constant standby loss term.

Table 2.16: Customer Monthly Bill Impacts With Multiple Rebates

Monthly Bill Impacts ($/month)	SDHW Cost	Energy Saved	Demand Saved	Multiple Rebates D,G	Multiple Rebates D,G,E PSCW	Multiple Rebates D,G,E High
System	$	kWh	kW	$/yr	$/yr	$/yr
SYS2B:30W	2100	3142	0.630	16.92	23.48	38.76
SYS2B:PV	2600	3227	0.660	13.86	20.57	36.22
SYS3B:30W	3200	3735	0.630	13.04	21.45	39.29
SYS1B:30W	1800	2453	0.577	12.12	17.39	29.67
SYS2: 30W	2300	2674	0.563	10.18	15.88	29.23
SYS3B:PV	3700	3816	0.660	10.68	18.48	36.67
SYS1B:PV	2300	2538	0.607	9.05	14.48	27.13
SYS2:PV	2800	2758	0.593	7.10	12.96	26.67
SYS3: 30W	3500	3260	0.563	6.16	12.95	28.82
SYS1: 30W	2000	1955	0.465	4.79	9.16	19.39
SYS1:PV	2500	2061	0.495	1.85	6.41	17.07
SYS3:PV	4000	3340	0.593	3.04	9.98	26.19

The average weekday hot water draw of a typical family of four is seventy gallons. Since over one-third of Wisconsin residential customers do not have access to natural gas, solar-electric DHW systems have good replacement potential in Wisconsin. Over two-thirds of Wisconsin residential customers are single family households. All but one of Wisconsin's utilities are summer peaking utilities, due to high electric air conditioning loads on hot sunny days. Solar DHW systems have significant peak demand reducing potential in the summer.

Three differently sized systems of one and two-tank configurations with either 30 W pumps or photovoltaic pumps were analyzed. A least cost production model and hourly weather and utility load data (for 1991) were used for the utility impacts analysis. The marginal emission reduction, avoided generation costs, energy savings, peak demand reduction, and contribution to utility capacity were evaluated for a typical electrical DHW systems, twelve solar-electric DHW systems, a typical natural gas DHW system, and six solar-gas DHW systems.

Solar DHW systems are found to be economically feasible from both a supply-side utility perspective and a customer monthly bill analysis. Photovoltaic pumps do not appear to be as cost effective as 30 W pumps from either perspective, due to high initial costs. However, single-tank SDHW systems consistently performed better and were more economically attractive from both cost perspectives. Issues about hot water run-outs associated with decreased storage volume were not addressed. Based on the before mentioned analyses and assumptions, solar DHW systems have significant economic and environmental potential in the state of Wisconsin.

Similar detailed analyses for all utilities in the country would be most beneficial to determine the impacts of SDHW nationwide. Hourly weather (temperature and radiation) and hourly utility load and dispatch information are necessary for accurate analyses. The need for an all inclusive database of this information (including weather data), similar to the Federal Energy Regulatory Commission (FERC) database is paramount.

2.10 Summary

The benefits of a large ensemble of solar domestic hot water (SDWH) systems are identified and quantified. These include reduced energy use, electrical demand, and pollution. The avoided emissions, capacity contribution, energy and demand savings were evaluated from the power generation schedules, emissions data and annual hourly load profiles of a Wisconsin utility. It is shown that each 6 m^2 SDWH system can save annually: 3,560 kWh of energy, 0.66 kW of peak demand, and over 4 tons of pollution.

The cost perspective evaluates all direct costs associated with the purchase and operation of the best available technology for electric power production. It also considers three levels of emission monetization: zero, the Public Service Commission of Wisconsin (PSCW) recommendations, and the highest values found in the literature for each pollutant.

Five of the 12 SDHW systems studied provide energy that costs less than the energy from a new technology combustion turbine ($0.06/kWh) even without credit for emission reduction. When the diversified solar systems receive credit for emission reductions (at the PSCW monetization levels), all but one of the SDHW systems are competitive with the gas combustion turbine, five of them are less expensive than the intermediate coal plant, and two of these systems less expensive than energy from the baseload plants. When the highest published emission monetization is used, all of the solar systems are less expensive than the baseload plants, and six SDHW systems save the utility money per each kWh produced over their lifetime.

A customer's monthly bill impact analysis assumed that the utility purchases the solar systems and the customers pay back for the systems through their monthly electric bills over the the systems' lifetime. The least expensive systems do not necessarily save the most money, and the systems with the most energy savings are not necessarily the most cost-effective ones.

Scenarios for utility rebates, based on avoided generation costs, peak demand reduction, and emission monetization were considered. Without rebates, three SDHW systems provide the customer with a positive monthly cash flow. With a utility rebate for demand reduction, nine of the twelve SDHW systems provide a similar impact. When multiple utility rebates for peak demand reduction, avoided generation costs, and emission reductions were given, all SDHW systems resulted in positive cash flows for the customer. SDHW systems have therefore significant economic and environmental potential in the state of Wisconsin. Since each utility's resource mix, weather, water mains, temperature, and load profiles have a unique impact on emission, energy and demand reduction, a proper analysis of SDHW potential requires utility-specific data.

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