CHAPTER
SIX

RESULTS

Variations of three differently sized solar systems were compared with a typical electric DHW system (fifty-two gallons, 4.5 kW electrical resistance heating elements, EF= 0.87). Although natural gas is unavailable to over a third of Wisconsin, conventional natural gas systems for solar back-up heating were also analyzed.

6.1 DHW Comparison Systems

Three collector area/storage tank size combinations were considered. In addition, both one and two tank variations of each solar system size were modeled. The third component variable for each solar system size was the pump type. Systems used either a parasitic thirty watt pump or a photovoltaic pump (also representative of a passive natural convection system), as discussed in Chapter 4.2: Solar DHW System Types. All DHW system parameters are listed in Table 6.1.1.

Table 6.1.1: 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**
Conventiona 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

6.2 Annual Energy Savings

The energy savings from various solar DHW system sizes can be estimated with the F-Chart computer program (Klein and Beckman, 1992). F-Chart uses Typical Meteorological Year (TMY) monthly weather and water mains temperatures, coupled with the RAND water draw profile (See Chapter 3.3: Average Load Representation). The TRNSYS simulation used the real 1991 hourly weather data, monthly water mains temperatures, and the WATSIM derived weekday and weekend water draw profiles. Annual solar energy contribution can be conveniently expressed in terms of a solar fraction. Solar fraction is defined as the percentage of the conventional energy requirements that were met by the solar system:

$$\text{Solar Fraction: } f = \frac{Q_{conv} - Q_{aux}}{Q_{conv}} \qquad \textbf{6.2.1}$$

Q_{conv} is the energy required by the conventional DHW system and Q_{aux} is the auxiliary energy required to meet the same load with a solar DHW system.

The comparison of the energy requirements and solar fractions calculated by both F-Chart and TRNSYS are shown in Table 6.2.1 (for System 1 with a PV pump). There are slight variations due to the difference in 1991 and TMY weather, mains temperatures and differences in the DHW models (The TRNSYS model is much more detailed). The F-Chart solar fractions show a good agreement with the solar fractions predicted by TRNSYS.

Table 6.2.1: F-Chart and TRNSYS Monthly Solar Fractions

Month	Solar Aux. (kWh)	Elec. (kWh)	TRNSYS SF(%)	F-Chart SF(%)
January	438	533	17.8	16.3
February	348	476	26.8	27.6
March	349	519	32.7	40.0
April	260	490	46.9	50.3
May	216	501	56.8	58.4
June	141	479	70.6	64.9
July	159	485	67.2	66.5
August	179	485	63.2	62.7
September	240	483	50.3	52.8
October	343	506	32.2	40.5
November	419	499	16.1	20.5
December	443	521	15.0	10.2
Annual	**3535**	**5975**	**41.3**	**42.6**

Annual electrical energy requirements for the twelve solar DHW systems and the conventional electric DHW system are compared in Figure 6.2.1. 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 thirty watt electric pump adds an additional 83 kWh of energy per year per system in comparison to a PV pump or passive system (less than $10/yr). 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 (see Chapter 3: TRNSYS Simulation Model). 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.

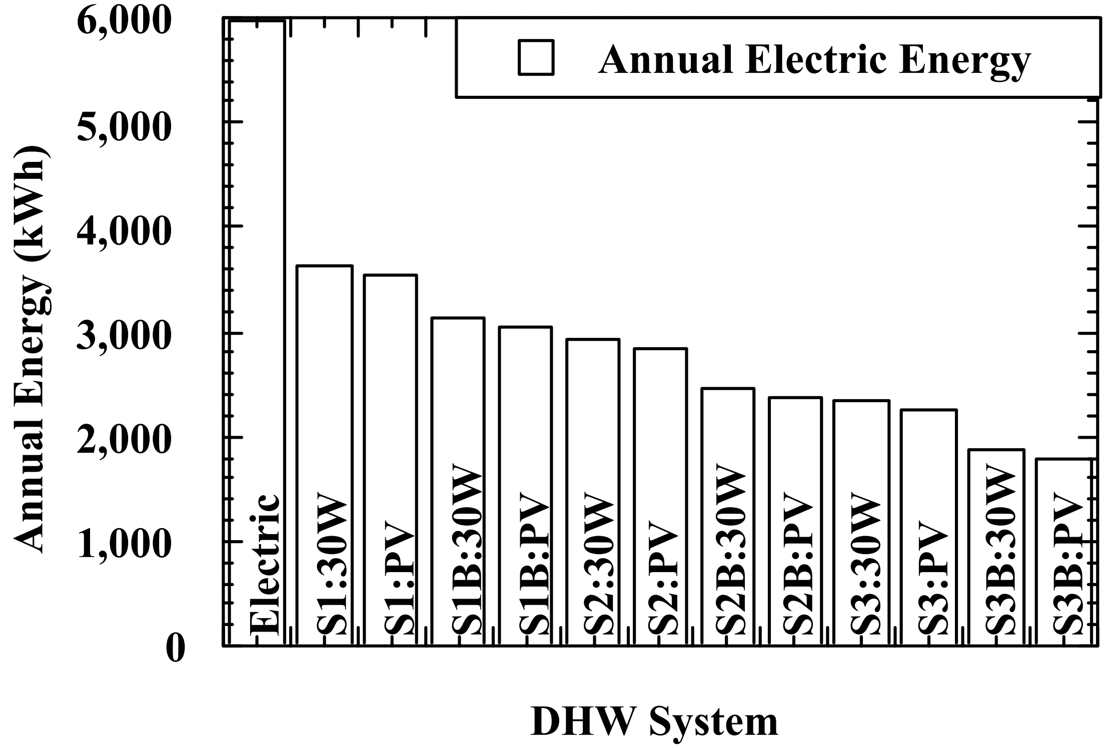

Figure 6.2.1: Comparison of Various Solar DHW Systems vs.Conventional Electric 1991 Annual Electricity Requirements

The energy requirements for conventional DHW systems vary according to the seasonal mains water temperatures (see Chapter 4.4: Water Mains 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 are compared with the conventional electric DHW systems in Figure 6.2.2.

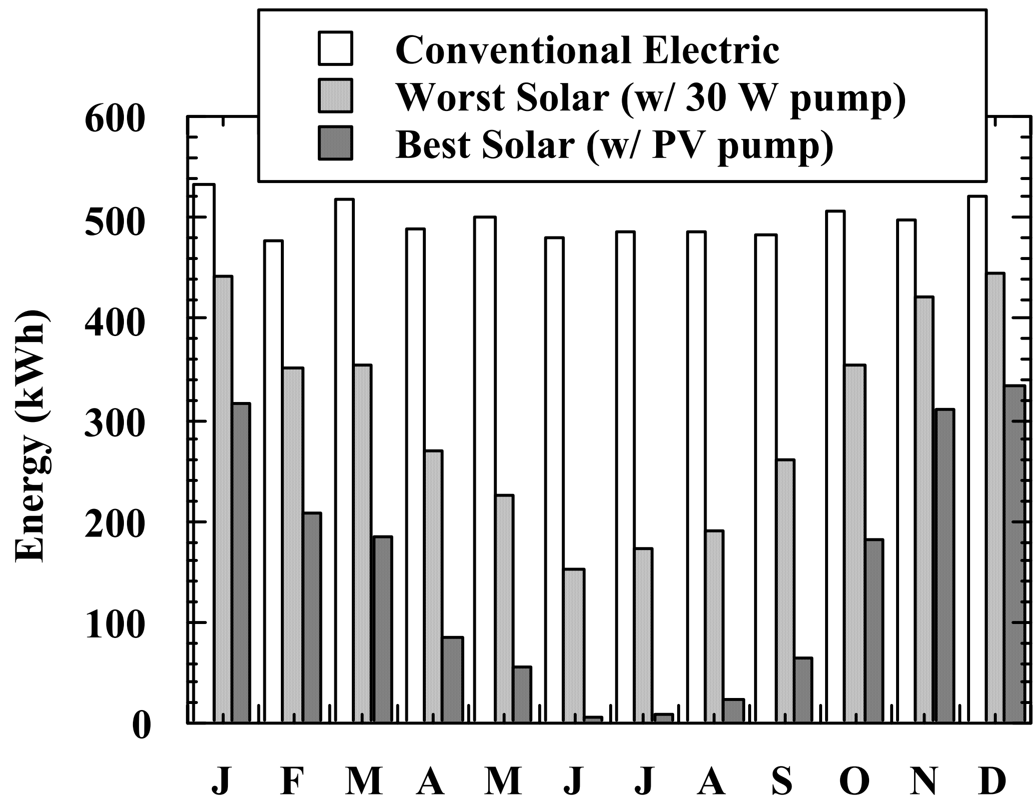

Figure 6.2.2: 1991 Monthly Energy Requirements for Various DHW systems

From the dispatch order calculated in Chapter 5, the gas combustion turbines were operated 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 of the year. The impacts of the best and worst solar DHW systems (from an energy savings standpoint) are compared with the conventional electric system for the different operating periods in Figure 6.2.3. An interesting combination of plants at the margin, in conjunction with the timing of DHW demands can be seen in Figure 6.2.3. Solar systems provide significant energy savings during all types of marginal plant operation, except base coal and nuclear plants. The solar system impacts during coal plant operation result in significant emission reduction (see Section 6.4: Emission Reduction).

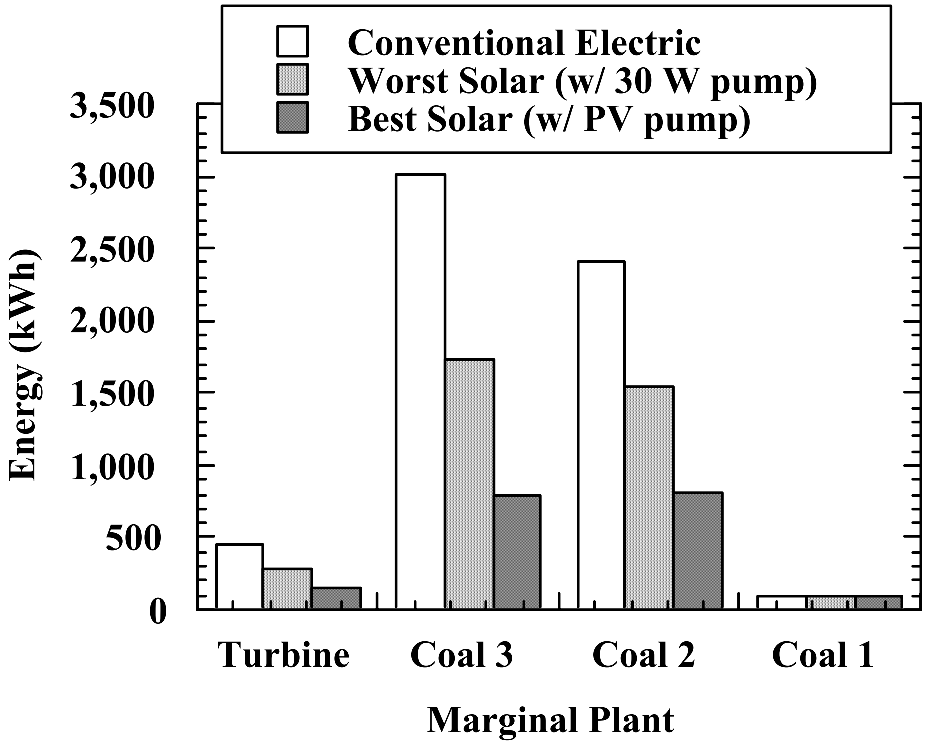

Figure 6.2.3: 1991 WEPCO
Annual Energy Reduction of Marginal Plant Operation

6.3 Peak Day Demand Reduction

Due to electric air conditioning loads, all Wisconsin utilities (except Dairyland Power Cooperative) experience their highest demands in the summer. The need to purchase power from other utilities or operate expensive gas combustion turbines has forced summer peaking utilities to analyze demand-side management programs (such as air-conditioner timers) as a means to lower their peak summer demand. Fortuitously, 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 6.3.1 where the solar system demand (from auxiliary heating) at the peak utility demand hour are compared against the conventional system.

Table 6.3.1: 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

The difference between the solar DHW and conventional DHW demands is termed the “peak demand reduction” of the solar system. The value to the utility for these peak demand reductions can be up to one thousand dollars per kilowatt. The value of the peak demand reduction potential of solar DHW systems, inspired SMUD in Sacramento, California to offer rebates up to $863 per solar DHW system (IRT, 1993).

The Wisconsin Center for Demand-Side Research lists the value for demand reduction to Wisconsin utilities as $ 72.97 per kW per year (WCDSR, 1994).

The energy savings for the twelve solar system models are ordered from largest to smallest solar system size and within each size category by tank configuration (one tank being better than two) and pump type (PV being better than a 30 W pump). Determination of the rankings (also shown in Table 6.3.1) for peak utility demand reduction is not in the same order as the energy savings for each solar system.

While Table 6.3.1 lists the solar DHW system in order of increasing annual energy savings, the systems with the highest demand reduction are the one-tank systems (2 &3) with PV pumps. The one-tank systems (2&3) with 30 watt 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.

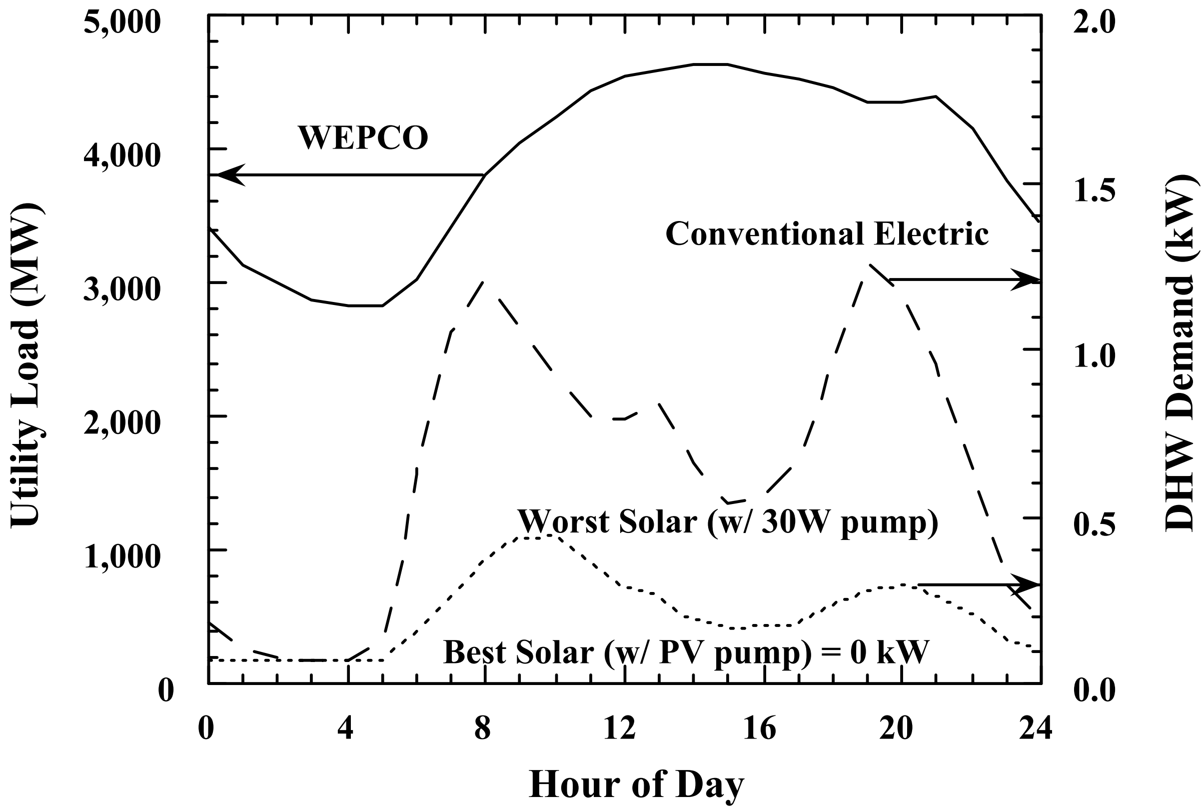

Figure 6.3.1: WEPCO Peak Day (Thursday August 29, 1991)
DHW Demand Comparison

6.4 Annual and Monthly Emission Savings

While the societal costs for various pollutants are a subject of debate, the actual amounts of pollutants avoided through solar DHW system replacement are only dependent on characteristics of the marginal power plant (see Chapter 2.2: Environmental Externalities). *Advance Plan 7* lists the following airborne pollutants as products of fossil fuel combustion: carbon dioxide, sulfur dioxide, nitrous oxide, oxides of nitrogen, methane, and particulates (PSCW, 1994).

Table 6.4.1: 1991 WEPCO Annual Emissions for Various Electric DHW Options

DHW Systems			Annual Environmental Impact					
			CO_2	SO_2	N_2O	NO_X	CH_4	Part.
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

Based on the operation of each WEPCO plant, the annual results in Table 6.4.1 show the amount of each measured pollutant produced by the various marginal plants to meet the electric requirements of each system (see Chapter 5.5: Marginal Emission Calculation). From a marginal emission approach, the average conventional system operation produces nearly six and one half tons of airborne pollutants! Based on the same hot water loads, the "best" (case 12) and "worst" (case 1) solar DHW systems save annually four and one half tons and two and one half tons of pollutants (respectively) when compared to the conventional electric DHW system.

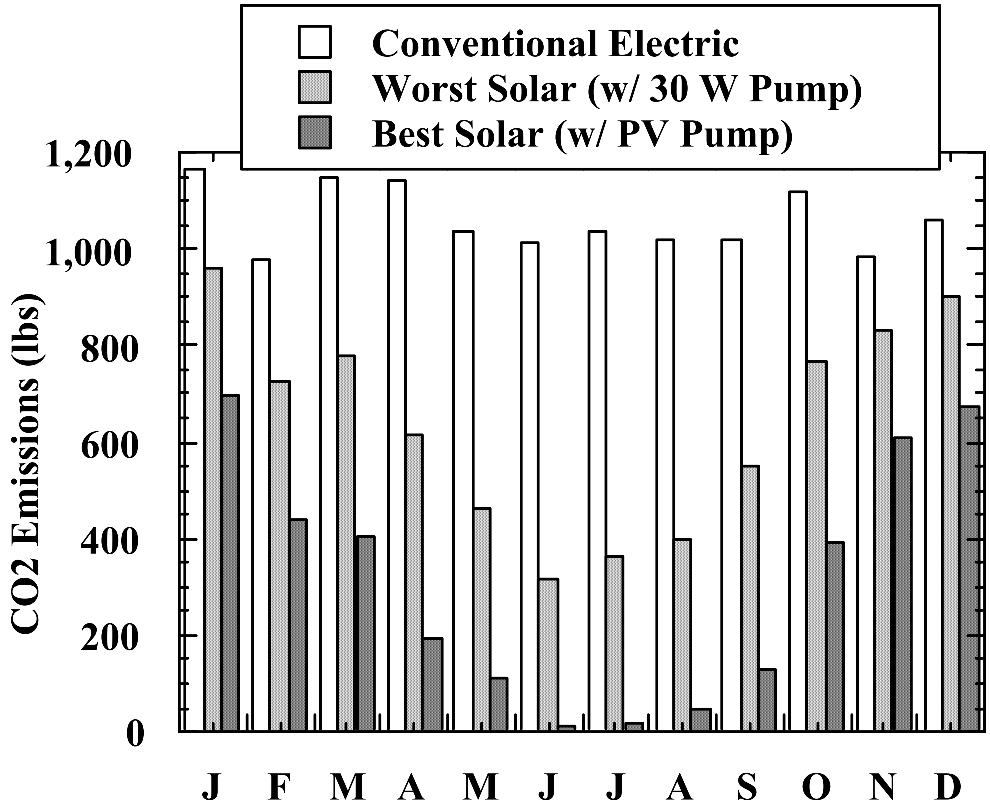

Figure 6.4.1: 1991 WEPCO Carbon Dioxide Monthly Emissions

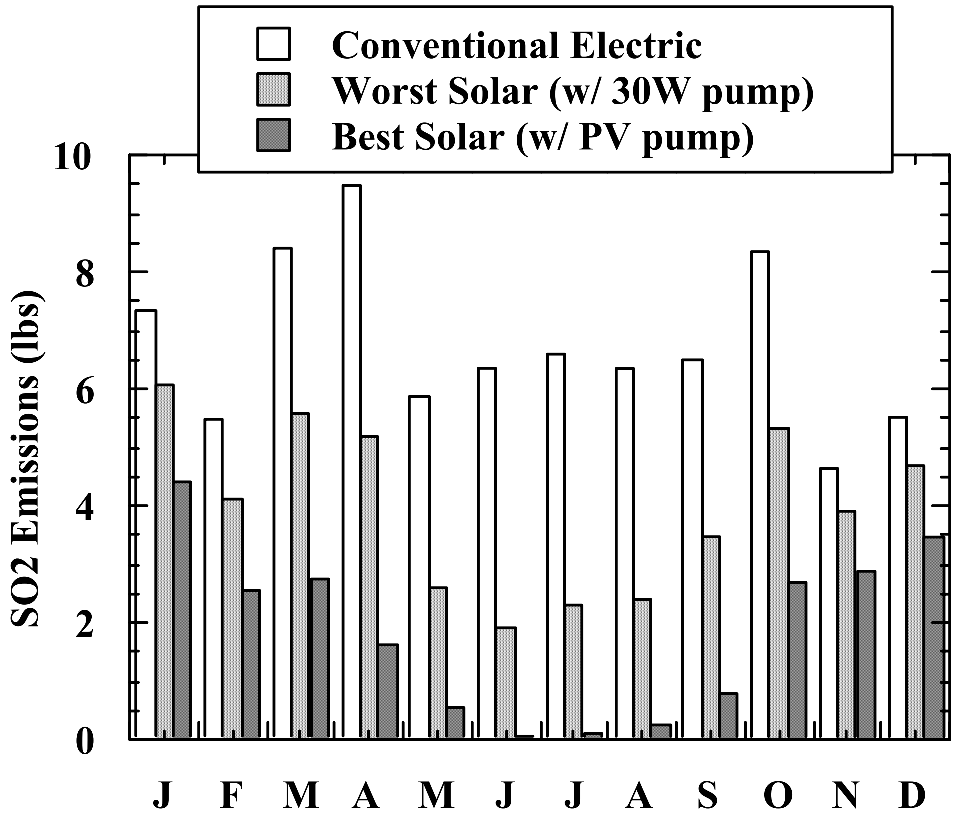

Figure 6.4.2: 1991 WEPCO Sulfur Dioxide Monthly Emissions

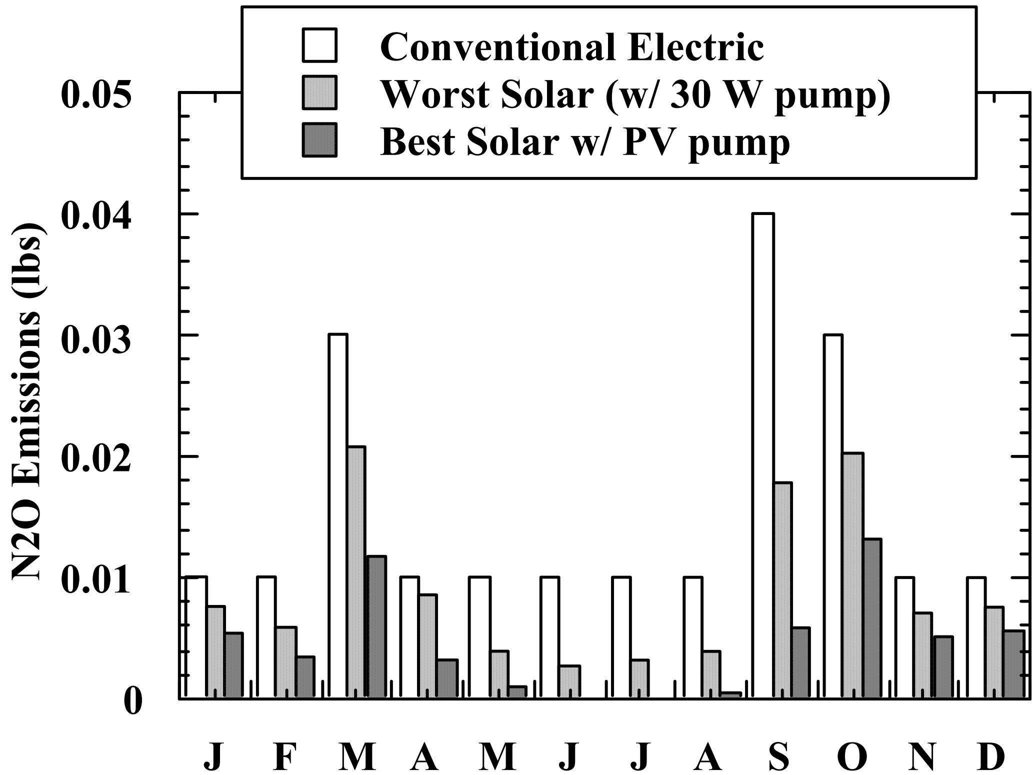

Figure 6.4.3: 1991 WEPCO Nitrous Oxide Monthly Emissions

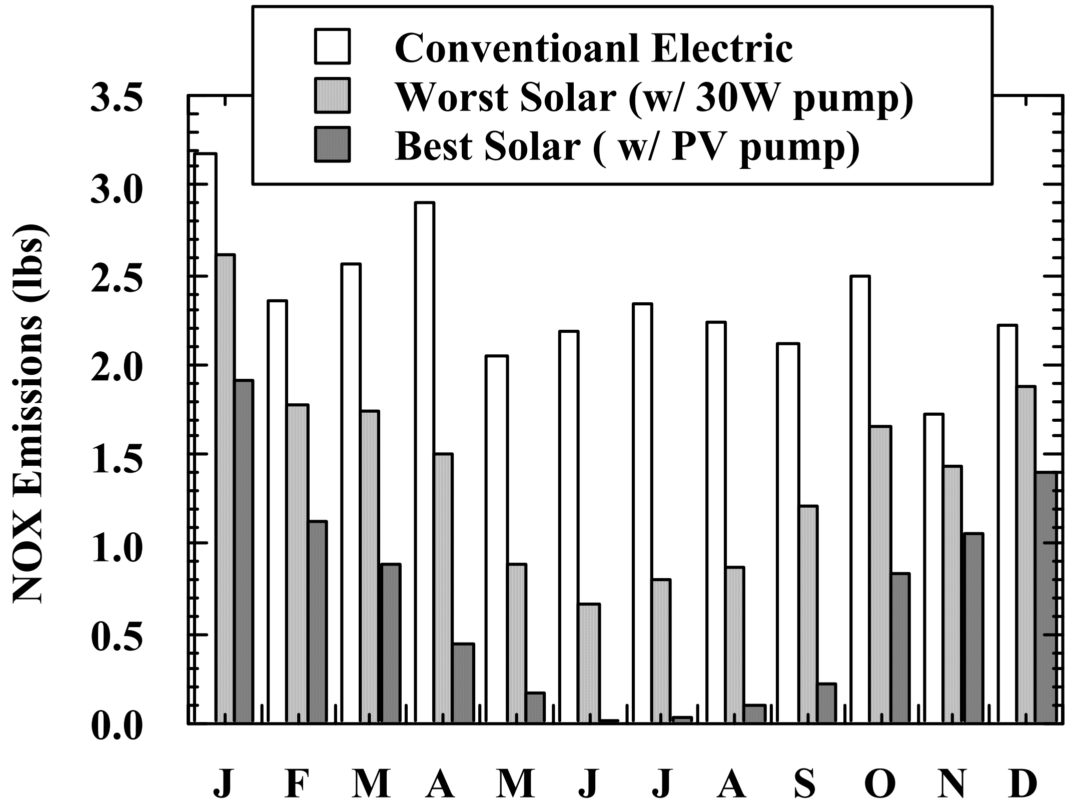

Figure 6.4.4: 1991 WEPCO Oxides of Nitrogen Monthly Emissions

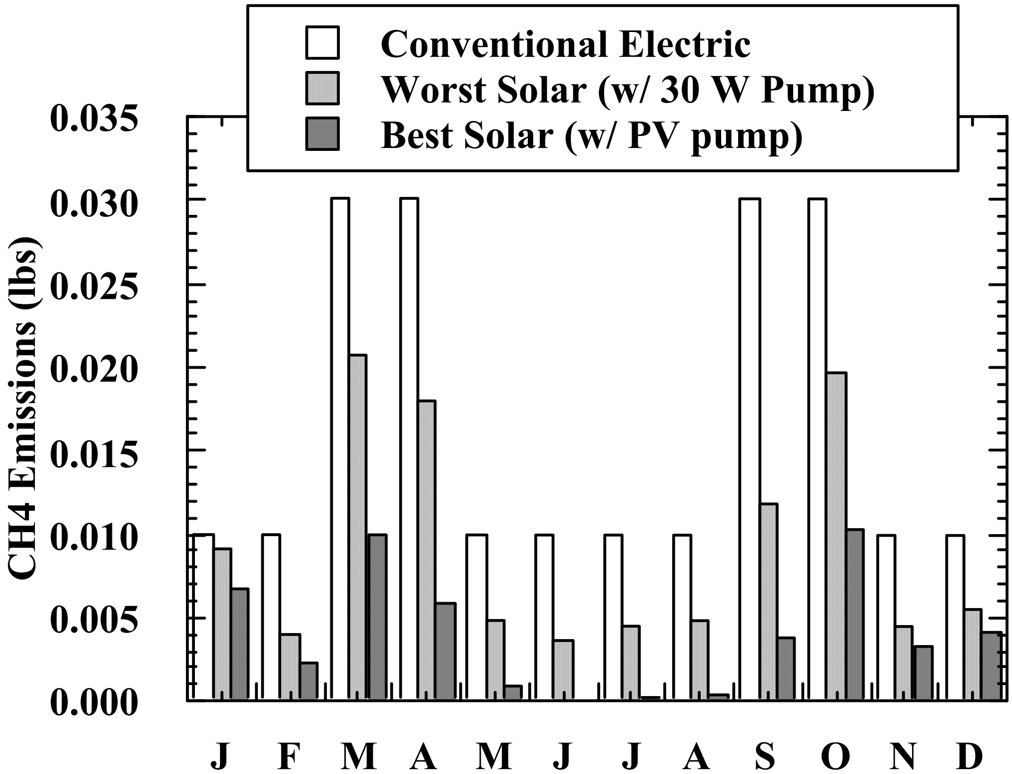

Figure 6.4.5: 1991 WEPCO Methane Monthly Emissions

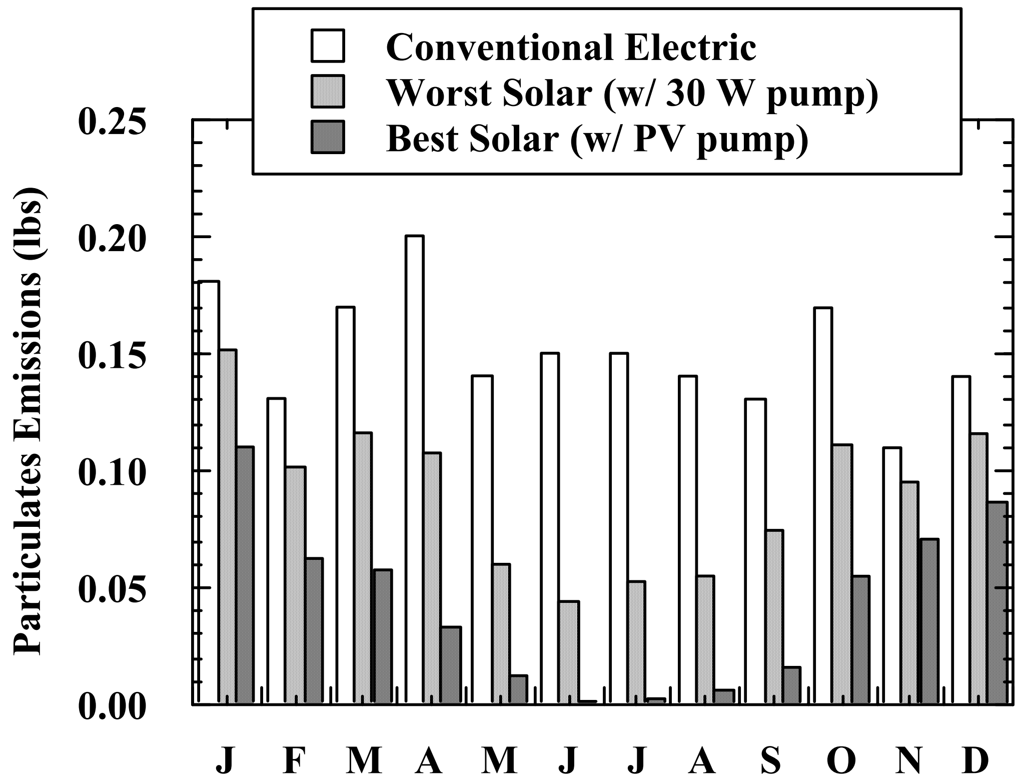

Figure 6.4.6: 1991 WEPCO Particulates Monthly Emissions

The monthly emissions from the operation of a conventional electric DHW system and the "best" and "worst" solar DHW systems for carbon dioxide, sulfur dioxide, nitrous oxide, oxides of nitrogen, methane, and particulates are compared in Figures 6.4.1-6. 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 the other three pollutants (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 conventional electric DHW system (see Chapter 5.3: Forced and Scheduled Outage Adjusted Capacity). 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.

The monthly emission graphs are very important for realizing the benefits of solar DHW system replacement. Traditionally, solar DHW systems are only given credit for reducing annual energy requirements and 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 are given merit.

6.5 Natural Gas DHW System Results

Although over a third of Wisconsin electric utility customers do not have access to natural gas, for comparison purposes the same solar systems shown in Table 6.1.1 were simulated (except the single-tank "B" models) with a natural gas heating system. The conventional natural gas tank was modeled as a 60 gallon tank with a 70% combustion efficiency and 3.5% standby losses. All but two of the solar DHW systems with natural gas back-up tanks required more energy annually than the conventional electric DHW system (5596 kWh). The increased energy requirements are due to higher standby losses and lower combustion efficiencies than the electric systems (see Chapter 4: DHW Systems). The energy requirement difference between the PV pumped systems and the systems with the thirty watt pump were only 83 kWh per year. The natural gas DHW systems have lower operating costs due to the extremely low cost of natural gas ($0.60/therm for customers and $0.25/therm for utilities). The natural gas DHW systems were modeled only from the customer perspective. Information about the impact on a gas utility due to solar-gas systems is beyond the scope of this project.

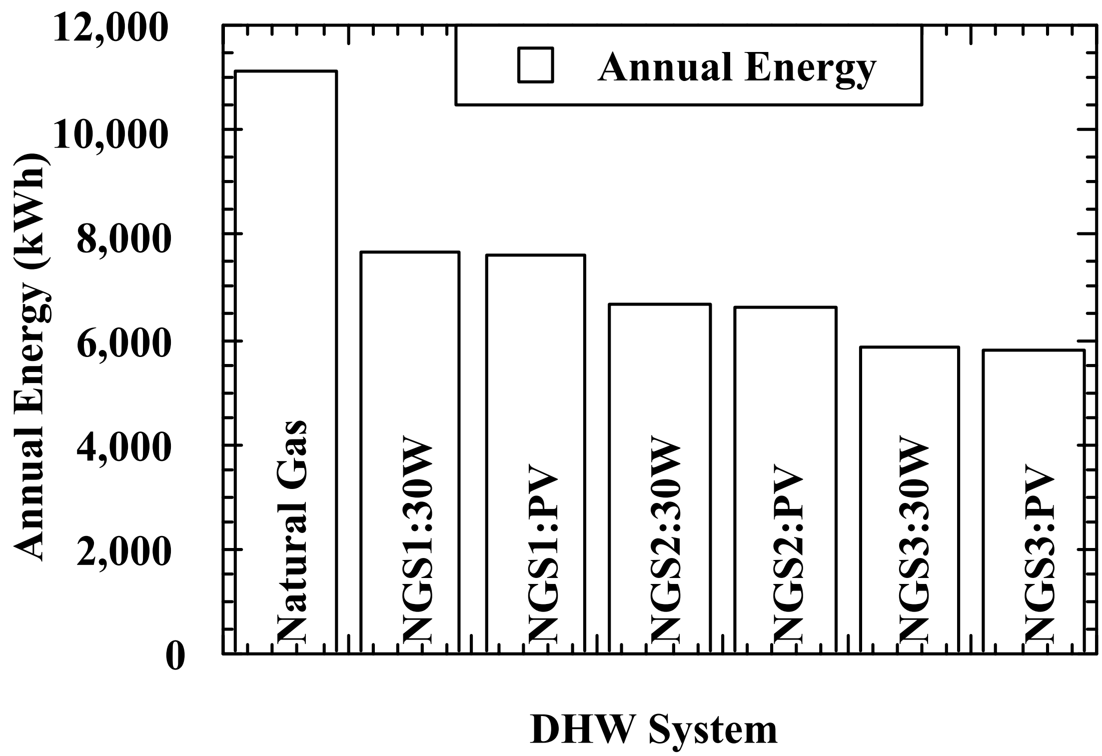

Figure 6.5.1: 1991 DHW Natural Gas Requirements for Various Solar DHW Systems Compared to Conventional Gas

It appears that natural gas systems have a greater energy impact than equivalent electric DHW systems, but one must but keep in mind a source to site perspective in which conventional power plants have efficiencies of less than 30%. Therefore, the overall energy requirements for the natural gas systems, when compared to the inefficiencies of electricity sources, are less than the electric DHW systems. Natural gas systems, while considered more benign to the environment than electricity production, are not without some environmental impacts.

Based on natural gas combustion emission levels of 127 lbs/MBtu for CO_2, 0.0006 lbs/MBtu for SO_2, and 0.09 lbs/MBtu for NO_X (and the annual emissions from the 30W pump for appropriate cases), the annual emissions for the various solar-gas DHW systems are shown in Table 6.5.1.

Table 6.5.1: 1991 WEPCO Annual Emissions for Various Gas DHW Options

DHW Systems		Annual Environmental Impact					
		CO_2	SO_2	N_2O	NO_X	CH_4	Part.
Tank Set-up	**Pump**	**lb**	**lb**	**lb**	**lb**	**lb**	**lb**
Typical Gas DHW	Elec	11903	0.02	x	3.411	x	x
Solar 1 2 Tanks	30W	3478	1.176	0.003	2.793	0.003	0.026
Solar 1 2 Tanks	PV	3302	0.016	x	2.340	x	x
Solar 2 2 Tanks	30W	3046	1.174	0.003	2.420	0.003	0.026
Solar 2 2 Tanks	PV	2870	0.014	x	2.034	x	x
Solar 3 2 Tanks	30W	2678	1.172	0.003	2.159	0.003	0.026
Solar 3 2 Tanks	PV	2502	0.012	x	1.773	x	x

6.6 Utility Savings: Real Levelized Cost

The Customer-Meter Real Levelized Cost analysis is a 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" (see Chapter 5.6.1: Supply-Side Utility Analysis). 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 using the utility peak hour DHW demand reduction as the nominal capacity is shown in Appendix D. The unit cost of electricity with the higher nominal capacity (in Appendix D) are a best case cost scenario. Included in the cost analysis are utility purchase and installation (the utility would purchase the SDHW systems in this scenario), 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 (see Chapter 5.5 CCI Calculation). Appendix D contains the equations for the Customer-Meter Unit Cost of Electricity and an example (Microsoft Excel) spreadsheet.

The cost analysis compares the utility cost (in $/year and $/kWh) for each power plant. The cost perspective evaluates all utility costs associated with the purchase and operation of the best available technology for electric power production. The two baseload plants, two intermediate load plants, and one peaking combustion turbine were chosen for comparison with the "diversified solar plant" (all plant information was obtained from the Public Service Commission of Wisconsin. All new technologies were considered to operate at the E.P.A. New Source Performance Standards for emission production. The costs per unit of energy produced ($/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 calculated in Section 6.4: Annual Emission Reductions). The various real levelized costs are shown Table 6.6.1 (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).

Table 6.6.1: 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-Passive	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**

The first unit electricity cost result ($/kWh) does not penalize the new technologies for their emissions, neither does it give credit to the "diversified solar plants" for their emission reductions. The second and third listed unit electricity costs ($/kWh) 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 Chapter 5. The solar credits were given for the PSCW and high emission monetization values from Chapter 2.2: Environmental Externalities.

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 (PSCW) 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!

6.7 Customer Perspective Cost Analysis

While supply-side screening of solar DHW system may seem overzealous, demand-side screening of the same SDHW systems also shows positive results. The monthly bill impact analysis described in Chapter 5.6.2 was performed for each of the twelve solar DHW system variations. The cost analysis was performed 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. The reasoning is as follows. If the energy savings outweigh the system cost and maintenance, than the customer would experience a reduced monthly electricity bill.

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

6.7.1.

Table 6.7.1: Values for Solar System Costs and Savings

Solar System	System Cost $	Energy Saved kWh	Demand Reduction kW	Avoided Generation $/yr	PSCW Pollution $/yr	High Pollution $/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

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 6.7.2. The sensitivity of each chosen parameter, included the initial SDHW system cost were also tested and are shown in Appendix D.

Table 6.7.2: Base Case Economic Parameters

Parameter	Symbol	Value
System Lifetime	N_e	15 years
Fuel Inflation Rate	i_{fuel}	3 %
Annual Maintenance	O&M	25 $/year
Discount Rate	d	5.5 %
Customer Electricity Cost	$C_{elec.}$	0.08 $/kWh

The results for the twelve solar DHW systems are shown in Table 6.7.3 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, three 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), nine of the twelve solar DHW systems provide positive customer electric bill impacts. Two the two-tank systems with PV pumps had negative monthly bill impacts even with a modest rebate.

When multiple utility rebates for peak demand reduction (D), 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 6.7.4.

Table 6.7.3: Customer Monthly Bill Savings

Bill Impact ($/month)	System Cost	NRG saved	Dmd Sav.	Base Case	Dmd Rebate	Avoided Gen.	Emission Credit PSCW	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

Table 6.7.4: Customer Monthly Bill Impacts With Multiple Rebates

Monthly Bill Impacts ($/month)	SDHW Cost	NRG saved	Dmd. Sav.	Multiple Rebates D,G	D,G,EP SCW	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

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 watt 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.