CHAPTER

# FIVE

## METHODOLOGY: UTILITY IMPACT ANALYSIS

This research is attempting to evaluate the true costs of solar water heating by analyzing ensemble solar DHW system: 1) contribution to utility capacity, 2) hourly energy reduction, 3) peak demand reduction, and 4) emission reduction. 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 most utility load forecasting, due to temperature effects on residential heating and cooling requirements. 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. Sales are based on estimated weather and weather normalized data. The Advance Plan gives information in the format shown in Table 5.0.1. The tables for all utilities are found in Appendix C. For a detailed discussion of utility operations see Chapter 2.1.3: Integrated Resource Planning.

To make projections of the interaction of different power plants in a utility network, Table 5.1.1 must be organized in an understandable and useful order. Based on the full-capacity average heating rates, the fuel costs, and the variable operating and maintenance costs, the generating costs for each plant unit were normalized to (\$/kWh). This information was then used for a comparison of each power plant based on a least cost dispatch model. The variable costs per unit of energy are listed in dispatch order in Section 5.3, for their respective operating periods. The methodology for the utility dispatch order of different forms of power generation is the least cost production model, also demonstrated in Section 5.3. Using the least cost dispatch order, the marginal plant analysis can be performed to predict the generation costs and emissions resulting from the operation of each DHW system.

**Table 5.0.1: WEPCO Plants Operating & Cost Characteristic (PSCW-AP7: D24, 1994)**

| WEPCO | | | Costs | | | Average Heating Rates (Btu/KWh) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Nominal | O&M | | | Minimum | | Partial | | Full | |
| Plant Name | Unit | Capacity | Variable | Fixed | Fuel | | Heat Rate | | Heat Rate | | Heat Rate |
| | (#) | (MW) | ($/MWH) | (1000$) | ($/MBtu) | (MW) | (Btu/kWh) | (MW) | (Btu/kWh) | (MW) | (Btu/kWh) |
| Point Beach | 2 | 497 | 0.8 | 28632 | 0.38 | 150 | 11816 | 174 | 10721 | 173 | 10508 |
| | 1 | 497 | 0.8 | 29189 | 0.38 | 150 | 11818 | 174 | 10729 | 173 | 10528 |
| Oak Creek | 8 | 305 | 0.76 | 7479 | 1.48 | 110 | 9983 | 85 | 9140 | 110 | 9155 |
| | 7 | 280 | 0.76 | 7594 | 1.48 | 110 | 9983 | 85 | 9140 | 85 | 9155 |
| | 6 | 260 | 1.02 | 6855 | 1.48 | 80 | 10956 | 83 | 9420 | 97 | 9347 |
| | 5 | 258 | 1.02 | 6835 | 1.48 | 75 | 11189 | 83 | 9450 | 100 | 9334 |
| Port Wash. | 4 | 80 | 7.84 | 2291 | 1.57 | 21 | 14774 | 30 | 12227 | 29 | 11983 |
| | 3 | 82 | 7.45 | 2278 | 1.57 | 21 | 11321 | 30 | 10295 | 31 | 10359 |
| | 2 | 80 | 3.57 | 2266 | 1.57 | 21 | 11867 | 30 | 10426 | 29 | 10420 |
| | 1 | 80 | 3.43 | 2250 | 1.57 | 21 | 13360 | 30 | 11037 | 29 | 10753 |
| Valley | 4 | 70 | 1.38 | 2361 | 1.71 | 1 | 12612 | 35 | 11793 | 34 | 11853 |
| | 3 | 70 | 1.38 | 2361 | 1.71 | 42 | 15160 | 14 | 13547 | 14 | 12659 |
| | 2 | 62 | 1.38 | 2308 | 1.71 | 1 | 12258 | 31 | 11680 | 30 | 11710 |
| | 1 | 64 | 1.38 | 2383 | 1.71 | 50 | 13061 | 7 | 12615 | 7 | 12295 |
| Pleasant Pr. | 2 | 580 | 0.92 | 8161 | 0.75 | 140 | 15048 | 220 | 11326 | 220 | 10808 |
| | 1 | 580 | 0.92 | 8143 | 0.75 | 140 | 15048 | 220 | 11326 | 220 | 10808 |
| Presque Isle | 9 | 84 | 1.11 | 2302 | 1.88 | 55 | 11764 | 15 | 11544 | 14 | 11500 |
| | 8 | 83 | 1.11 | 2297 | 1.88 | 55 | 11764 | 14 | 11552 | 14 | 11499 |
| | 7 | 81 | 1.11 | 2210 | 1.88 | 55 | 11764 | 13 | 11561 | 13 | 11499 |
| | 6 | 85 | 0.67 | 2033 | 1.47 | 45 | 11721 | 20 | 10899 | 20 | 10600 |
| | 5 | 84 | 0.67 | 2013 | 1.47 | 45 | 11721 | 20 | 10899 | 19 | 10608 |
| | 4 | 57 | 0.56 | 1005 | 1.47 | 33 | 11075 | 12 | 10701 | 12 | 10662 |
| Presque Isle | 3 | 58 | 1.29 | 1073 | 1.47 | 33 | 11075 | 12 | 10701 | 13 | 10662 |
| | 2 | 37 | 16.74 | 596 | 1.47 | 20 | 14411 | 17 | 14350 | 0 | 0 |
| | 1 | 25 | 16.52 | 421 | 1.47 | 16 | 17309 | 9 | 16025 | 0 | 0 |
| Edgewater | 5 | 97 | 0.86 | 884 | 1.22 | 21 | 13133 | 38 | 10406 | 38 | 10429 |
| **Turbines** | | | | | | | | | | | |
| Concord | 4 | 83 | 2.92 | 74 | 3.42 | 38 | 15640 | 18 | 13880 | 27 | 12875 |
| | 3 | 83 | 2.92 | 74 | 3.42 | 38 | 15640 | 18 | 13880 | 27 | 12875 |
| | 2 | 83 | 2.92 | 74 | 3.42 | 38 | 15640 | 18 | 13880 | 27 | 12875 |
| | 1 | 83 | 2.92 | 74 | 3.42 | 38 | 15640 | 18 | 13880 | 27 | 12875 |
| Germantown | 4 | 53 | 0.57 | 98 | 4.36 | 30 | 15137 | 0 | 0 | 23 | 13627 |
| | 3 | 53 | 0.57 | 98 | 4.36 | 30 | 15137 | 0 | 0 | 23 | 13627 |
| | 2 | 53 | 0.57 | 98 | 4.36 | 30 | 15137 | 0 | 0 | 23 | 13627 |
| | 1 | 53 | 0.57 | 98 | 4.36 | 30 | 15137 | 0 | 0 | 23 | 13627 |
| Oak Creek | 9 | 20 | 3.65 | 232 | 3.42 | 4 | 32853 | 0 | 0 | 16 | 15228 |
| Point Beach | 5 | 20 | 0.84 | 42 | 4.36 | 4 | 31077 | 0 | 0 | 16 | 14407 |
| Port Wash. | 6 | 18 | 0.59 | 122 | 4.36 | 4 | 31077 | 0 | 0 | 14 | 14793 |

## 5.1 Utility Load - Weather Interaction

Utilities have to report their annual hourly load information to the Federal Energy Regulatory Commission (FERC), which is the national public utilities commission (see Chapter 2.2.2: Clean Air Act Amendments). The Edison Electrical Institute (EEI) is a lobbying group for utilities. Most utilities have their load profiles recorded on an hourly basis using an EEI format. The 1991 utility load profile (in EEI format), accompanied by 1991 ambient temperature and radiation, were obtained for the Wisconsin Electric Power Company located in Milwaukee, Wisconsin. To test the representativeness of this year (used for the *Advance Plan 7*, 1994 forecasting), the Typical Meteorological Year (TMY) weather data for Milwaukee were compared to the 1991 weather data. Table 5.1.1 shows the comparison between 1991 and TMY average temperatures and radiation.

**Table 5.1.1: Milwaukee Monthly Weather Comparison**

| Month | 1991 $T_{amb}$ (F) | TMY $T_{amb}$ (F) | 1991 Rad. (kJ/m$^2$-hr) | TMY Rad. (kJ/m$^2$-hr) |
|---|---|---|---|---|
| **January** | 20.16 | 22.10 | 279.6 | 231.9 |
| **February** | 30.19 | 25.78 | 381.9 | 314.8 |
| **March** | 37.90 | 32.51 | 494.8 | 530.9 |
| **April** | 49.08 | 44.63 | 694.6 | 686.4 |
| **May** | 65.03 | 54.98 | 814.5 | 814.0 |
| **June** | 70.37 | 65.72 | 1023.6 | 960.2 |
| **July** | 74.17 | 69.92 | 926.6 | 954.2 |
| **August** | 72.93 | 69.35 | 803.6 | 837.3 |
| **September** | 63.07 | 61.48 | 619.4 | 626.8 |
| **October** | 51.86 | 51.81 | 393.6 | 418.0 |
| **November** | 34.88 | 38.84 | 239.5 | 260.6 |
| **December** | 29.46 | 25.29 | 215.0 | 178.9 |

Both the 1991 hourly temperature and incident radiation are representative in comparison to the TMY data. There were a few outliers in the 1991 hourly radiation. These were possibly due to experimental measurement error from the National Climatic Data Center or the effect of reflection off nearby clouds during partly cloudy conditions. In these cases, the questionable 1991 radiation data exceeded extraterrestrial radiation for that time period and were replaced with TMY radiation for that hour.

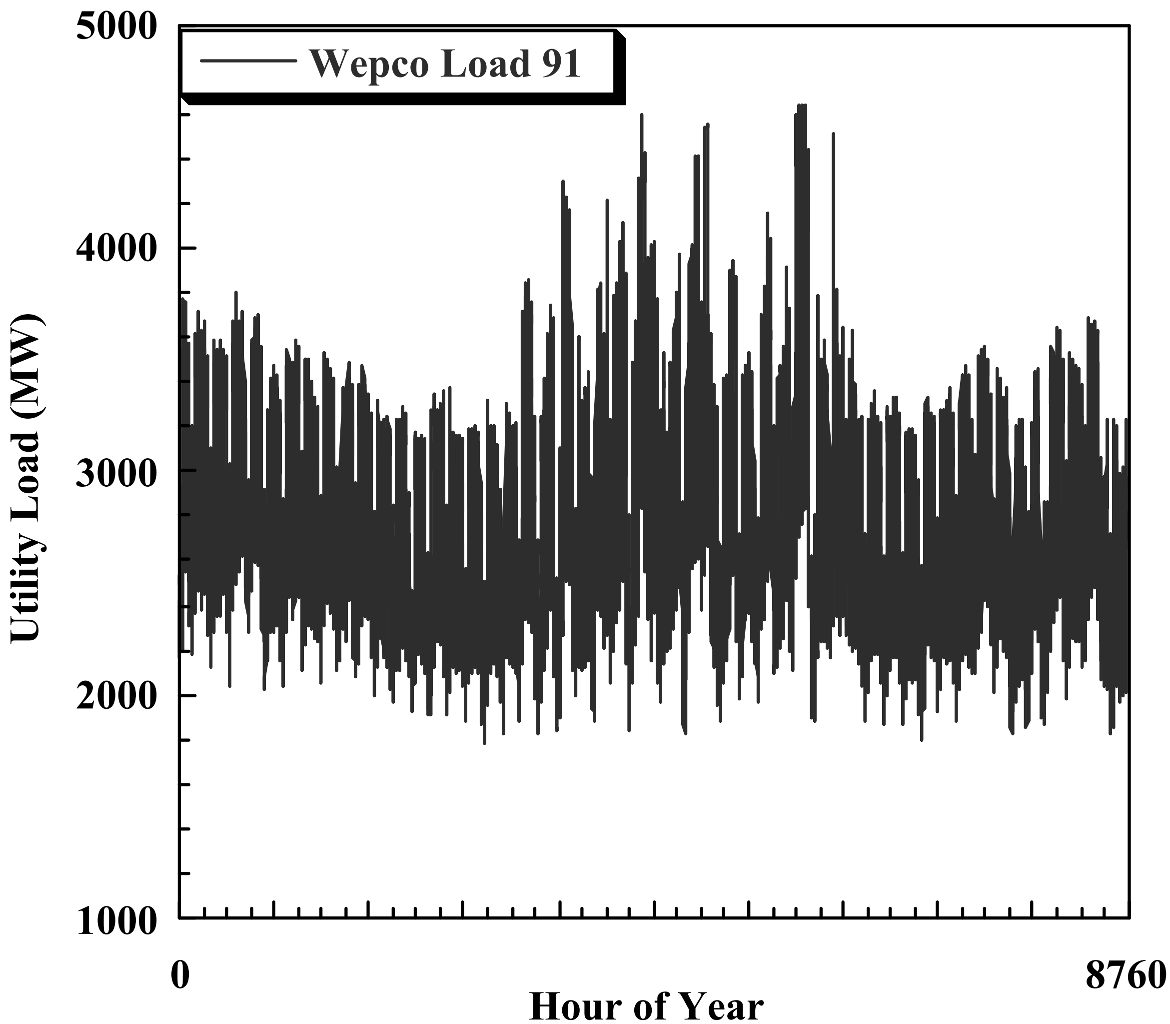


**Figure 5.1.1: WEPCO of Milwaukee 1991 Load**

The 1991 hourly utility demand in MW is shown in Figure 5.1.1. This figure demonstrates the winter and summer seasonal utility load peaks, as well as the cyclic day into night pattern. A more useful representation of the annual utility load is discussed in Section 5.5.2: Load Duration Curves.

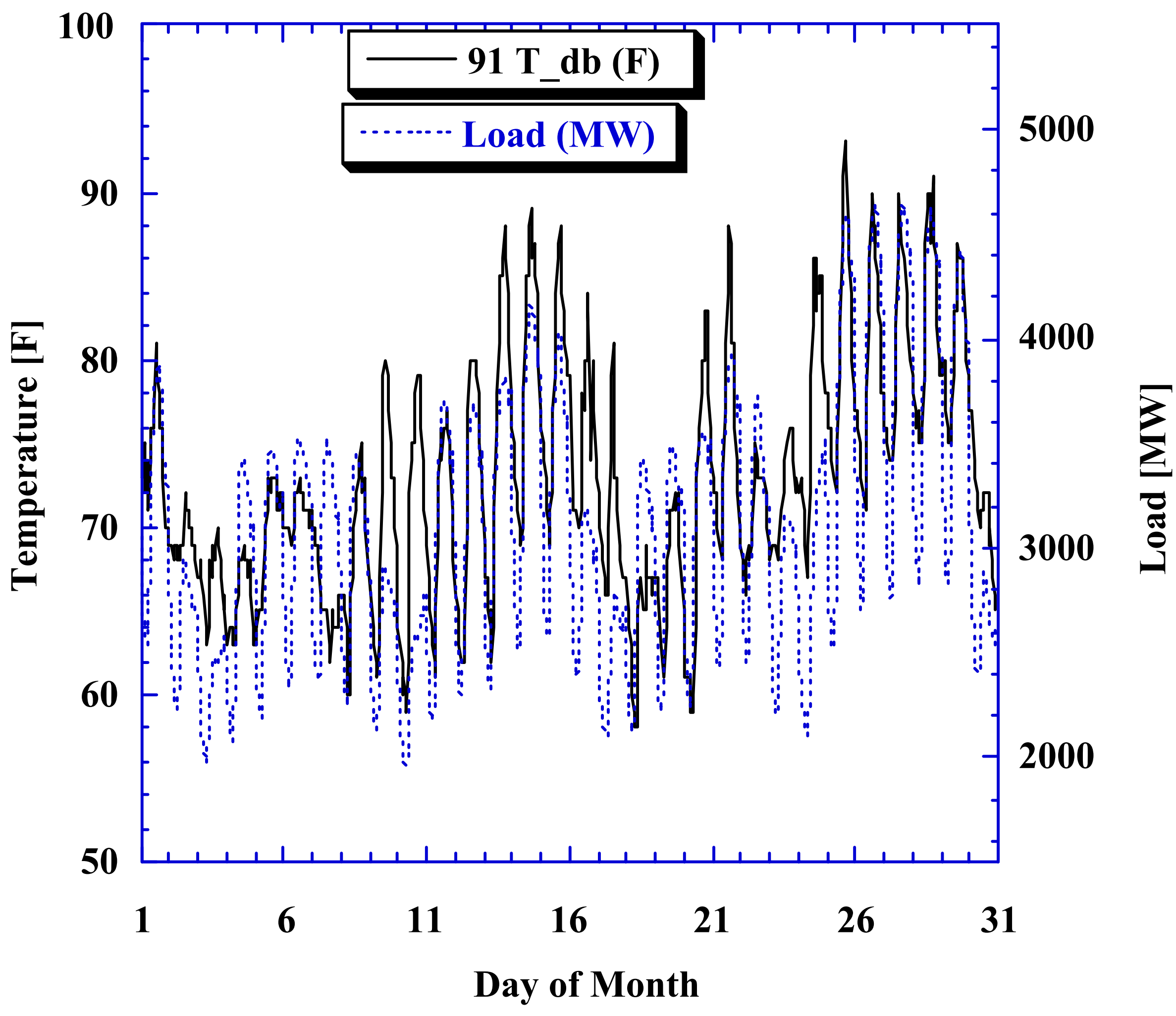


**Figure 5.1.2: August 1991 Milwaukee Temperature and WEPCO Load**

Figure 5.1.2 shows how the August load directly follows the ambient temperature. While the peak temperature occurred on Monday, the peak utility demand occurred on

Thursday, August 29th, due to electric air conditioning loads on the fourth of four consecutive hot, sunny days.

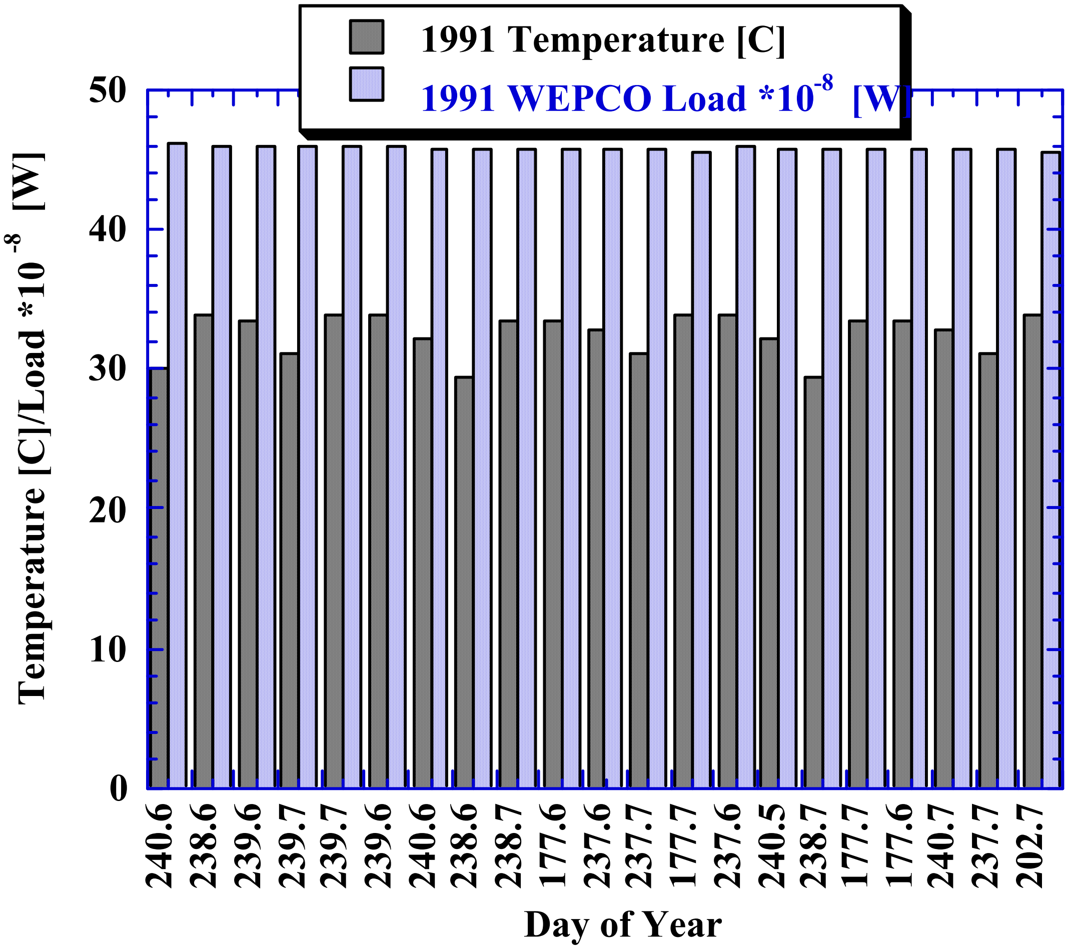


**Figure 5.1.3: Top Twenty 1991 WEPCO Demand Hours (& Temperature)**

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 Figure 5.1.3. Power is produced expensively with combustion gas turbines, or purchased expensively from other utilities on the grid, during these peak utility demand hours. The importance of the utility capacity during these peak periods is shown in Figure 5.5.1, and discussed in Section 5.5: Capacity Contribution Index.

## 5.2 Load Duration Curves

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. A load duration curve is derived by plotting the hourly demands of the utility (Figure 5.1.3) in descending order. The utility load changes throughout the day and throughout the year. However, the load duration curve disregards the timing of the load and shows the number of hours that the utility experienced a certain level of demand. Figure 5.2.1 is the most useful representation of the utility load and it can be used to determine the type of generation unit that is dispatched for each level of utility load. For forecasting purposes, the load duration curve can also be normalized (since the hourly average demands vary from year to year) by dividing all values by the system peak demand of the base year. 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.

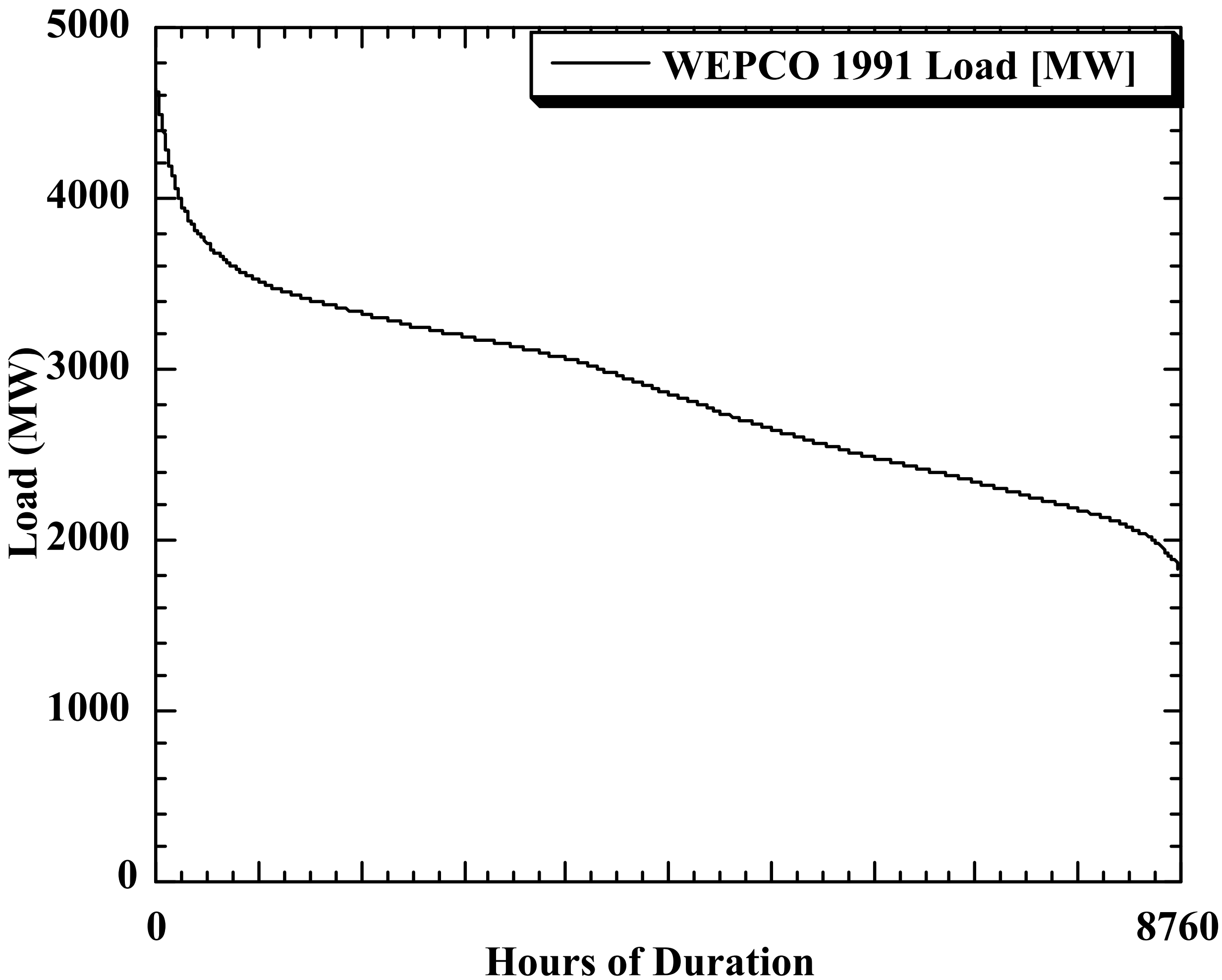


**Figure 5.2.1: WEPCO 1991 Load Duration Curve**

The *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 output if it were 100% available. The total possible output of a unit is 8760 hours times the capacity. The actual output is 8760 times capacity times capacity factor (both in MWh). 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 (e.g., purchased). Since a least cost production model is performed considering no purchases of energy from other utilities on the grid, the capacity factor listed for WEPCO is not what is used for a load duration curve with a simplified power generation schedule. A third capacity adjustment only accounts for the outages related to availability. Outage adjusted capacity factors are derived in Section 5.3 from the *Advance Plan 7* outage characteristics shown in Table 5.3.1.

## 5.3 Forced and Scheduled Outage Adjusted Capacity

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 and predictive statistics. The duration of the scheduled outages (for planned maintenance) is known, but the exact dates of a particular unit being off-line for annual maintenance are not listed (or known) in the forecasting documents. The *Advance Plan 7* listing of the forced and scheduled outage information is shown in Table 5.3.1. By including the forced outage adjusted capacity factor (applied to the nominal capacity of each listed generation unit in the AP7 D24), 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, as shown in Table 5.3.2. Table 5.3.1 gives both forced and scheduled outage rates. Scheduled outages (for maintenance) are not likely occur during peak periods, but the possibility of a forced outage, i.e., due to failure, could occur at any point. 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.

**Table 5.3.1: WEPCO Outage Characteristic (PSCW-AP7:D24, 1994)**

| WEPCO | | | Outages | | | |
|---|---|---|---|---|---|---|
| | | | Sched. | Forced | Outage | Rates. |
| Plant Name | Unit | Nominal Capacity | | Full | Partial Capacity | Partial |
| | (#) | (MW) | (Wks/yr.) | (%) | (MW) | (%) |
| Point Beach | 2 | 497 | 6 | 1.9 | 0 | 0.0 |
| | 1 | 497 | 6 | 1.9 | 0 | 0.0 |
| Oak Creek | 8 | 305 | 5 | 1.0 | 85 | 1.6 |
| | 7 | 280 | 5 | 1.0 | 85 | 1.6 |
| | 6 | 260 | 5 | 2.0 | 82 | 3.0 |
| | 5 | 258 | 5 | 2.0 | 82 | 2.9 |
| Port Wash. | 4 | 80 | 0 | 4.0 | 29 | 1.5 |
| | 3 | 82 | 0 | 4.0 | 29 | 1.4 |
| | 2 | 80 | 0 | 4.0 | 29 | 1.3 |
| | 1 | 80 | 0 | 4.0 | 29 | 1.3 |
| Valley | 4 | 70 | 0 | 2.5 | 34 | 4.0 |
| | 3 | 70 | 0 | 1.0 | 14 | 15.0 |
| | 2 | 62 | 8 | 2.5 | 30 | 3.9 |
| | 1 | 64 | 8 | 1.0 | 7 | 13.0 |
| Pleasant Pr. | 2 | 580 | 6 | 1.0 | 220 | 1.3 |
| | 1 | 580 | 6 | 1.0 | 220 | 1.3 |
| Presque Isle | 9 | 84 | 1 | 1.0 | 14 | 3.0 |
| | 8 | 83 | 1 | 1.0 | 14 | 3.0 |
| | 7 | 81 | 1 | 1.0 | 13 | 3.2 |
| | 6 | 85 | 1 | 1.0 | 20 | 2.2 |
| | 5 | 84 | 1 | 1.0 | 19 | 2.2 |
| | 4 | 57 | 1 | 1.0 | 12 | 2.4 |
| | 3 | 58 | 1 | 1.0 | 12 | 2.4 |
| | 2 | 37 | 0 | 0.0 | 0 | 0.0 |
| | 1 | 25 | 0 | 0.0 | 0 | 0.0 |
| Edgewater | 5 | 97 | 4 | 2.0 | 38 | 5.0 |
| **Turbines** | | | | | | |
| Concord | 1_4 | 83 | 0 | 1.0 | 0 | 0.0 |
| Germantown | 1_4 | 53 | 0 | 1.0 | 0 | 0.0 |
| Oak Creek[3] | 9 | 20 | 0 | 1.0 | 0 | 0.0 |
| Point Beach | 5 | 20 | 0 | 1.0 | 0 | 0.0 |
| Port Wash. | 6 | 18 | 0 | 1.0 | 0 | 0.0 |

**Table 5.3.2: Timing of Maintenance and Peak Periods**

| Month | Days | Day of Year | Start Hour | End Hour | Category |
|---|---|---|---|---|---|
| January | 31 | i | 1 | 744 | Peak |
| February | 28 | 31+i | 745 | 1416 | Peak |
| March | 31 | 59+i | 1417 | 2160 | Maintenance |
| April | 30 | 90+i | 2161 | 2880 | Maintenance |
| May | 31 | 120+i | 2881 | 3624 | Peak |
| June | 30 | 151+i | 3625 | 4344 | Peak |
| July | 31 | 181+i | 4345 | 5088 | Peak |
| August | 31 | 212+i | 5089 | 5832 | Peak |
| September | 30 | 243+i | 5833 | 6552 | Maintenance |
| October | 31 | 273+i | 6553 | 7296 | Maintenance |
| November | 30 | 304+i | 7297 | 8016 | Peak |
| December | 31 | 334+i | 8017 | 8760 | Peak |

For the peak period capacity values, the forced outage capacity adjustments (F.O.A) are calculated from Table 5.3.1 data by:

$$\text{F.O.A. Capacity} = 1 - \%\text{Full} - \left(\frac{\text{Partial MW}}{\text{Total Nominal MW}}\right) * \%\text{Partial} \qquad \textbf{5.3.1}$$

For the maintenance period capacity values, the forced and scheduled outage adjustments (F.&S.O.A.) are calculated from Table 5.3.1 by:

$$\begin{aligned}&\text{F.\&S.O.A. Capacity} = \text{F.O. Factor} - \text{S.O. Factor} \\ &= 1 - \%\text{Full} - \left(\frac{\text{Partial MW}}{\text{Total Nominal MW}}\right) * \%\text{Partial} - \left(\frac{\text{Scheduled Outage hours}}{\text{Total Maintenance hours}}\right)\end{aligned} \qquad \textbf{5.3.2}$$

These two capacity adjustments were applied to the nominal capacities from Table 5.1.1. The resulting peak and maintenance period capacities, with their associated generation costs of each plant are shown in Table 5.3.3 and Table 5.3.4, respectively.

The different forms of power generation, ordered for least cost ($/MWh), were then placed on separate load duration curves with their respective outage adjusted capacities. Figure 5.3.1 and Figure 5.3.2 are the peak and maintenance period load duration curves. The order shown on the load duration curves is the least cost generation schedule. It follows the basic unit dispatch; nuclear baseload plants first, then coal, and combustion turbines used for peaking (See Chapter 2.2.1: Utility Load Characteristics)

**Table 5.3.3: Peak Period Forced Outage Adjusted Capacity**

| WEPCO Plant Name | Unit (#) | F. O. Adj. Capacity (MW) | Fuel & O&M ($/kWh) | Ranking (least cost) | 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 |

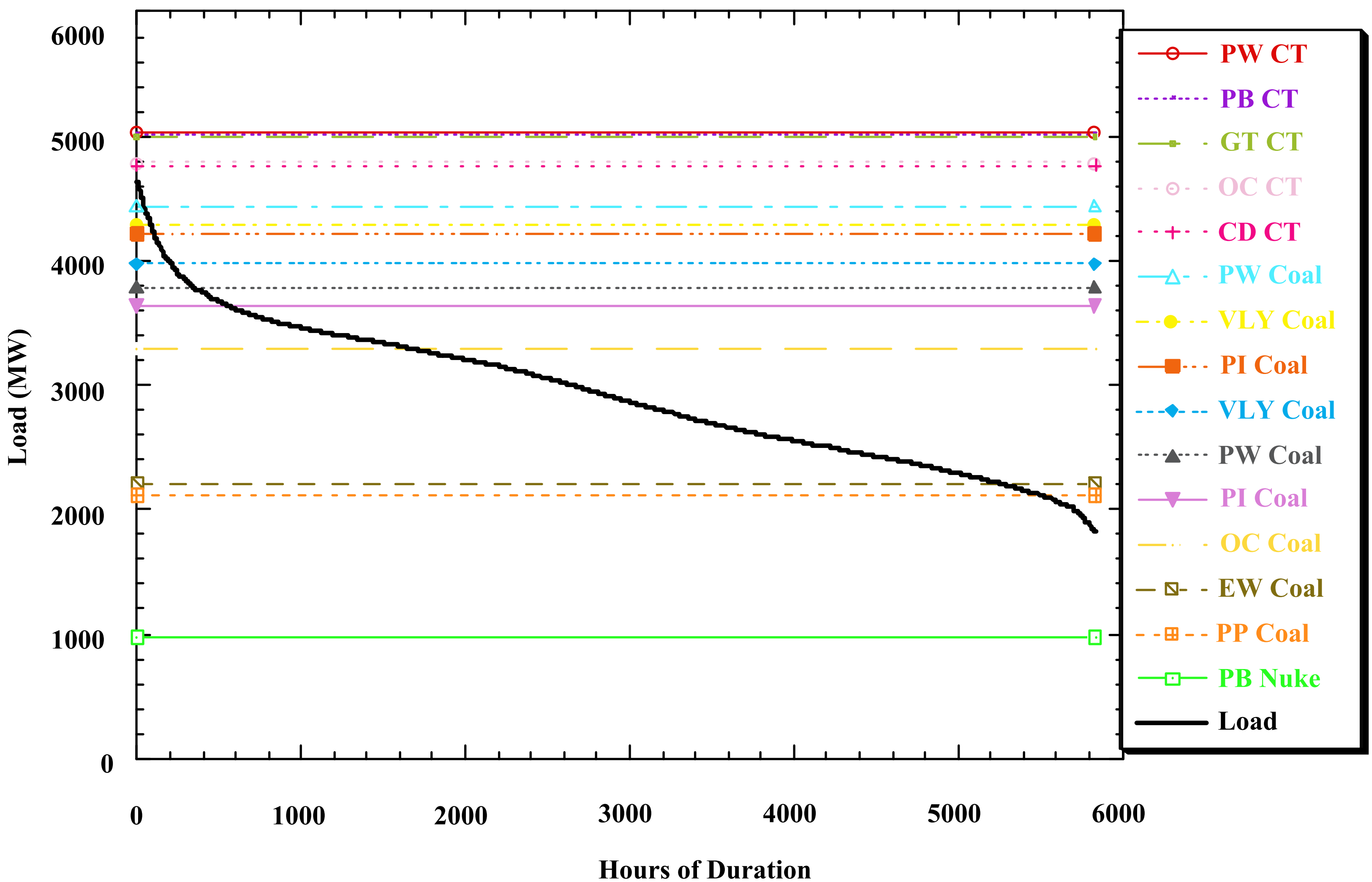


Figure 5.3.1: WEPCO Peak Period Load Duration Curve

**Table 5.3.4: Maintenance: Forced & Scheduled Outage Adjusted Capacity**

| WEPCO Plant Name | Unit (#) | F.&S.O. Capacity (MW) | Fuel & O&M Costs ($/kWh) | Ranking (least cost) | Cumulative Capacity (MW) |
|---|---|---|---|---|---|
| Point Beach | 2 | 310.47 | 0.0048 | 1 | 310 |
| Point Beach | 1 | 310.47 | 0.0048 | 2 | 621 |
| Pleasant Pr. | 2 | 364.68 | 0.0090 | 3 | 986 |
| Pleasant Pr. | 1 | 364.68 | 0.0090 | 4 | 1350 |
| Edgewater | 5 | 70.12 | 0.0136 | 5 | 1420 |
| Oak Creek | 8 | 210.03 | 0.0143 | 6 | 1630 |
| Oak Creek | 7 | 192.70 | 0.0143 | 7 | 1823 |
| Oak Creek | 5 | 173.86 | 0.0148 | 8 | 1997 |
| Oak Creek | 6 | 175.14 | 0.0149 | 9 | 2172 |
| Presque Isle | 4 | 52.76 | 0.0162 | 10 | 2225 |
| Presque Isle | 6 | 78.66 | 0.0163 | 11 | 2304 |
| Presque Isle | 5 | 77.75 | 0.0163 | 12 | 2381 |
| Presque Isle | 1 | 25.00 | 0.0165 | 13 | 2406 |
| Presque Isle | 2 | 37.00 | 0.0167 | 14 | 2443 |
| Presque Isle | 3 | 53.69 | 0.0170 | 15 | 2497 |
| Port Wash. | 2 | 76.42 | 0.0199 | 16 | 2573 |
| Port Wash. | 1 | 76.42 | 0.0203 | 17 | 2650 |
| Valley | 2 | 29.83 | 0.0214 | 18 | 2680 |
| Valley | 4 | 66.89 | 0.0216 | 19 | 2747 |
| Valley | 1 | 32.04 | 0.0224 | 20 | 2779 |
| Presque Isle | 9 | 77.75 | 0.0227 | 21 | 2856 |
| Presque Isle | 8 | 76.82 | 0.0227 | 22 | 2933 |
| Presque Isle | 7 | 74.96 | 0.0227 | 23 | 3008 |
| Valley | 3 | 67.20 | 0.0230 | 24 | 3075 |
| Port Wash. | 3 | 78.31 | 0.0237 | 25 | 3154 |
| Port Wash. | 4 | 76.37 | 0.0267 | 26 | 3230 |
| Concord | 4 | 82.17 | 0.0470 | 27 | 3312 |
| Concord | 3 | 82.17 | 0.0470 | 28 | 3394 |
| Concord | 2 | 82.17 | 0.0470 | 29 | 3477 |
| Concord | 1 | 82.17 | 0.0470 | 30 | 3559 |
| Oak Creek | 9 | 19.80 | 0.0557 | 31 | 3579 |
| Germantown | 4 | 52.47 | 0.0600 | 32 | 3631 |
| Germantown | 3 | 52.47 | 0.0600 | 33 | 3684 |
| Germantown | 2 | 52.47 | 0.0600 | 34 | 3736 |
| Germantown | 1 | 52.47 | 0.0600 | 35 | 3788 |
| Point Beach | 5 | 19.80 | 0.0637 | 36 | 3808 |

| | | | | | |
|---|---|---|---|---|---|
| Port Wash. | 6 | 17.82 | 0.0651 | 37 | 3826 |

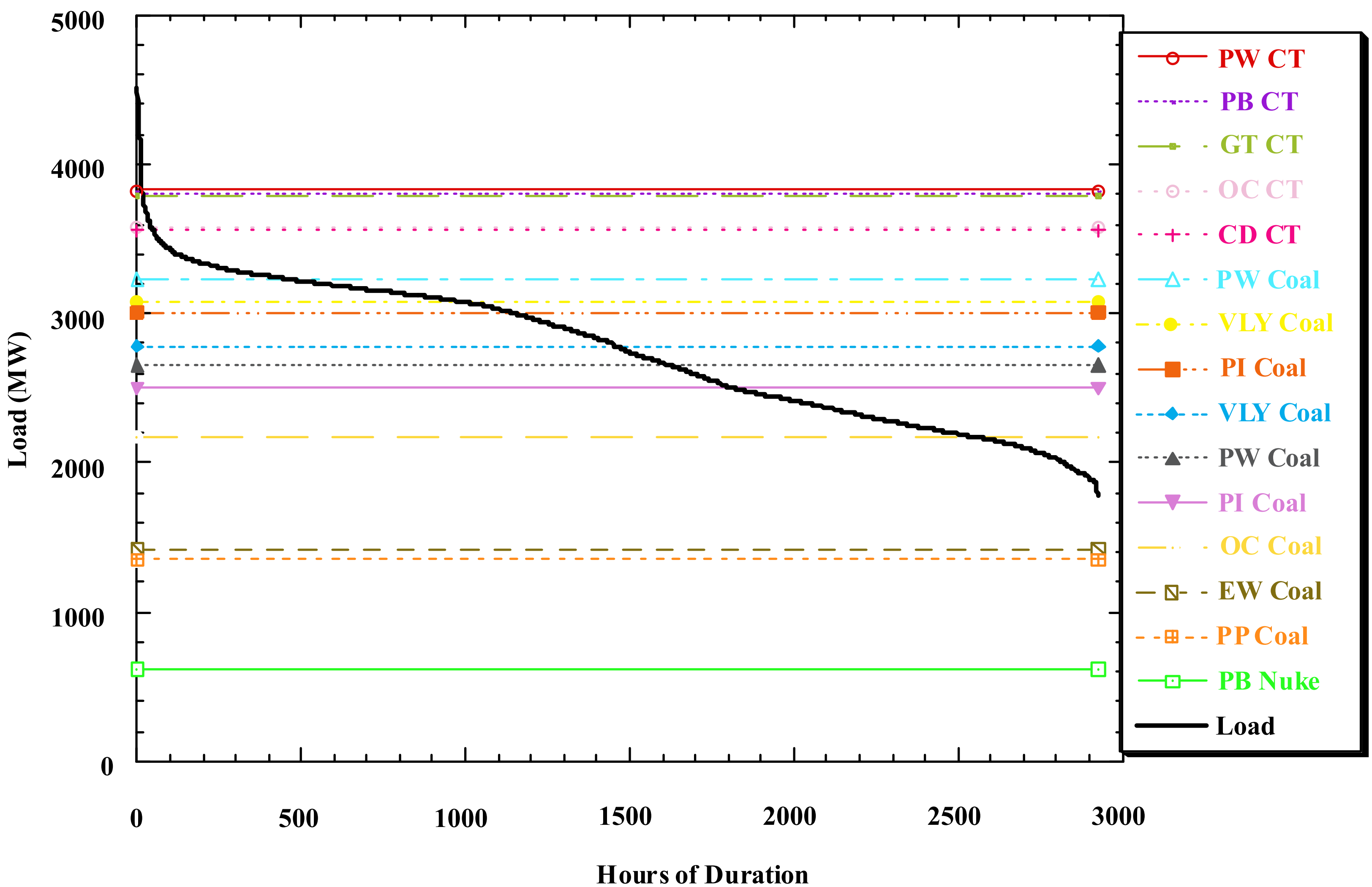


Figure 5.3.2: WEPCO Maintenance Period Load Duration Curve

To test the validity of the scheduling assumptions, actual costs, projected costs (*Advance Plan 7* ratings), and capacity factors are compared in Table 5.3.5. The actual data show that operating costs were higher in 1991 than the plant rating data predict. The actual data also take into account the capacity factor (the percentage of time the plant was operating during the hours that it was available) which accounts for times when it was cheaper to buy from another utility. One important note: the 1991 Advance Plan 7 data (for the predictions) were intended for forecasting purposes, so discrepancies with the actual data do not reflect poorly on the results. Yet, they do demonstrate the level of unpredictability that is involved in utility dispatch and relative unit generating costs.

A few important assumptions are supported through analysis of real operation and dispatch information. Interestingly, the predicted costs were usually less than the actual costs. The assumption of least cost dispatch is supported through the evidence that the least cost options having the highest capacity factor were operated for the most amount of time. One exception was one of two 500 MW nuclear units at Point Beach that was operated at four times its intended cost per kWh had an annual capacity factor of 79%. This exception shows that the largest and most reliable systems are still dispatched, even though their operational costs can be more than other options due to unforeseen problems. Thus, the impacts predicted by the 1994 values are conservative, when compared to the actual operating costs that were encountered in 1991.

**Table 5.3.5: WEPCO Projected and Actual Operating Costs**

| Plant Name | Unit (#) | F.O. Adj. Cap (MW) | 1991 Gen. ($/kWh) | Ratings from AP7 ($/kWh) | Cost Diff. ($/kWh) | Cost Diff. (%) | Actual CF (%) |
|---|---|---|---|---|---|---|---|
| Point Beach | 2 | 487.56 | 0.0044 | 0.0048 | -0.0004 | -8.93 | 80 |
| Point Beach | 1 | 487.56 | 0.0164 | 0.0048 | 0.0116 | 70.73 | 79 |
| Pleasant Pr. | 2 | 571.34 | 0.0121 | 0.0090 | 0.0031 | 25.40 | 70 |
| Pleasant Pr. | 1 | 571.34 | 0.0117 | 0.0090 | 0.0027 | 22.85 | 62 |
| Edgewater | 5 | 93.16 | 0.0172 | 0.0136 | 0.0036 | 21.03 | 53 |
| Oak Creek | 8 | 300.59 | 0.0162 | 0.0143 | 0.0019 | 11.67 | 36 |
| Oak Creek | 7 | 275.84 | 0.0157 | 0.0143 | 0.0014 | 8.86 | 54 |
| Oak Creek | 5 | 250.46 | 0.0164 | 0.0148 | 0.0016 | 9.55 | 48 |
| Oak Creek | 6 | 252.34 | 0.0161 | 0.0149 | 0.0012 | 7.74 | 51 |
| Presque Isle | 4 | 56.14 | 0.0198 | 0.0162 | 0.0036 | 18.01 | 56 |
| Presque Isle | 6 | 83.71 | 0.0182 | 0.0163 | 0.0019 | 10.70 | 83 |
| Presque Isle | 5 | 82.74 | 0.0192 | 0.0163 | 0.0029 | 15.29 | 83 |
| Presque Isle | 1 | 25.00 | 0.0489 | 0.0165 | 0.0324 | 66.22 | 1 |
| Presque Isle | 2 | 37.00 | 0.0275 | 0.0167 | 0.0108 | 39.13 | 2 |
| Presque Isle | 3 | 57.13 | 0.0190 | 0.0170 | 0.0020 | 10.72 | 47 |
| Port Wash. | 2 | 76.42 | 0.0278 | 0.0199 | 0.0079 | 28.31 | 10 |
| Port Wash. | 1 | 76.42 | 0.0274 | 0.0203 | 0.0071 | 25.87 | 10 |
| Valley | 2 | 59.28 | 0.0314 | 0.0214 | 0.0100 | 31.83 | 32 |
| Valley | 4 | 66.89 | x | 0.0216 | x | x | x |
| Valley | 1 | 62.45 | 0.0298 | 0.0224 | 0.0074 | 24.82 | 32 |
| Presque Isle | 9 | 82.74 | 0.0220 | 0.0227 | -0.0007 | -3.32 | 88 |
| Presque Isle | 8 | 81.75 | 0.0219 | 0.0227 | -0.0008 | -3.78 | 91 |
| Presque Isle | 7 | 79.77 | 0.0223 | 0.0227 | -0.0004 | -1.92 | 81 |
| Valley | 3 | 67.20 | x | 0.0230 | x | x | x |
| Port Wash. | 3 | 78.31 | 0.0251 | 0.0237 | 0.0014 | 5.52 | 11 |
| Port Wash. | 4 | 76.37 | 0.0267 | 0.0267 | 0.0000 | 0.17 | 10 |
| Concord | 4 | 82.17 | x | 0.0470 | x | x | x |
| Concord | 3 | 82.17 | x | 0.0470 | x | x | x |
| Concord | 2 | 82.17 | x | 0.0470 | x | x | x |
| Concord | 1 | 82.17 | x | 0.0470 | x | x | x |
| Oak Creek | 9 | 19.80 | x | 0.0557 | x | x | x |
| Germantown | 4 | 52.47 | 0.0813 | 0.0600 | 0.0213 | 26.22 | 0.4 |
| Germantown | 3 | 52.47 | 0.0774 | 0.0600 | 0.0174 | 22.50 | 0.7 |
| Germantown | 2 | 52.47 | 0.0776 | 0.0600 | 0.0176 | 22.70 | 0.8 |
| Germantown | 1 | 52.47 | 0.0774 | 0.0600 | 0.0174 | 22.50 | 0.7 |
| Point Beach | 5 | 19.80 | 0.1879 | 0.0637 | 0.1242 | 66.12 | 0.3 |
| Port Wash. | 6 | 17.82 | 0.2053 | 0.0651 | 0.1402 | 68.30 | 0 |
| **Average** | | **136.09** | **0.04 $/kWh** | **0.03 $/kWh** | **0.02 $/kWh** | **22.16 %** | |

## 5.4 Marginal Emission Calculations

Table 5.4.1 lists the ratings of WEPCO's power plants for various airborne pollutants. Both historical and projected emissions were given in the Advance Plan. 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. This research assumes that the utilities will follow the optimistic 1994 projected rates. The pollutants that are tallied are carbon dioxide, sulfur dioxide, nitrous oxide, oxides of nitrogen, methane, and particulates. The fossil fuel mix is given with a heating rate, and percentage sulfur and percentage ash, as a method of grading the coal.

**Table 5.4.1: WEPCO *Advance Plan 7:D24 Table 2***
**1994 Rates of Discharge of Significant Pollutants/Fossil Fuel Units**

| Plant | Unit | Capacity | $CO_2$ | $SO_2$ | $N_2O$ | $NO_X$ | $CH_4$ | Parti-culates | Total Ash | HHV | Sulfur | Ash |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Name | (#) | (MW) | (lb/MBtu) | | | | | | | Btu/lb | % | % |
| 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 |

**Table 5.4.2: 1994 WEPCO Average Annual Load Fossil Pollutant Rates**

| Plant Name | Unit (#) | Capacity (MW) | Emissions | | | (lb/MWh) | | |
|---|---|---|---|---|---|---|---|---|
| | | | $CO_2$ | $SO_2$ | $N_2O$ | $NO_X$ | $CH_4$ | Part. |
| Oak Creek | 8 | 305 | 1868 | 7.60 | 0.0165 | 2.56 | 0.010 | 0.183 |
| | 7 | 280 | 1868 | 7.60 | 0.0165 | 2.56 | 0.010 | 0.183 |
| | 6 | 260 | 1907 | 7.76 | 0.0168 | 2.62 | 0.010 | 0.187 |
| | 5 | 258 | 1904 | 7.75 | 0.0168 | 2.61 | 0.010 | 0.187 |
| Port Wash. | 4 | 70 | 2492 | 26.84 | 0.0180 | 4.31 | 0.191 | 0.479 |
| | 3 | 80 | 2155 | 23.20 | 0.0155 | 3.73 | 0.165 | 0.414 |
| | 2 | 70 | 2167 | 23.34 | 0.0156 | 3.75 | 0.166 | 0.417 |
| | 1 | 55 | 2237 | 24.09 | 0.0161 | 3.87 | 0.171 | 0.430 |
| Valley | 4 | 140 | 2436 | 26.58 | 0.0222 | 5.86 | 0.013 | 0.586 |
| | 3 | 140 | 2436 | 26.58 | 0.0222 | 5.86 | 0.013 | 0.586 |
| | 2 | 140 | 2436 | 26.58 | 0.0222 | 5.86 | 0.013 | 0.586 |
| | 1 | 125 | 2557 | 27.91 | 0.0234 | 6.15 | 0.014 | 0.615 |
| Pleasant Pr. | 2 | 580 | 2313 | 8.11 | 0.0184 | 4.32 | 0.014 | 0.108 |
| | 1 | 580 | 2313 | 8.11 | 0.0184 | 4.32 | 0.014 | 0.108 |
| Presque Isle | 9 | 84 | 2392 | 12.54 | 0.0173 | 8.05 | 0.014 | 0.230 |
| | 8 | 83 | 2392 | 12.53 | 0.0172 | 8.05 | 0.014 | 0.230 |
| | 7 | 85 | 2392 | 12.53 | 0.0172 | 8.05 | 0.014 | 0.230 |
| | 6 | 87 | 2237 | 16.54 | 0.0159 | 8.90 | 0.012 | 0.424 |
| | 5 | 84 | 2238 | 16.55 | 0.0159 | 8.91 | 0.012 | 0.318 |
| | 4 | 57 | 2250 | 16.63 | 0.0160 | 6.50 | 0.012 | 0.426 |
| | 3 | 58 | 2250 | 16.63 | 0.0160 | 6.50 | 0.012 | 0.320 |
| | 2 | 37 | 3028 | 22.39 | 0.0215 | 12.05 | 0.016 | 1.292 |
| | 1 | 25 | 3381 | 19.23 | 0.0240 | 13.46 | 0.018 | 0.321 |
| General CT | 1 | 50 | 3296 | 41.60 | 0.1600 | 13.60 | 0.000 | 0.800 |
| Concord | 4 | 83 | 1609 | 0.00 | 0.1803 | 1.16 | 0.004 | 0.000 |
| | 3 | 83 | 1609 | 0.00 | 0.1803 | 1.16 | 0.004 | 0.000 |
| | 2 | 83 | 1609 | 0.00 | 0.1803 | 1.16 | 0.004 | 0.000 |
| | 1 | 83 | 1609 | 0.00 | 0.1803 | 1.16 | 0.004 | 0.000 |

Utilizing a least cost production model, the marginal cost of electricity is the cost of the most expensive equipment running. A marginal emission analysis follows. Due to the twin peak of the average electric DHW load (see Figure 5.4.1), and the maintenance period generation schedule, the emission reductions due to solar DHW replacement occur not only during "clean" combustion turbine operation, but also during the "dirty" coal emissions. Since the actual times for forced and scheduled outages are not known, maintenance periods are the worst case scenarios for emissions and costs. For example, if the nuclear plant at WEPCO's Point Beach site was down for maintenance, the worst cost and pollutant (air born emissions) scenario would be in effect, because the more expensive cost plants and more polluting (from an airborne emission viewpoint) coal plants would be dispatched to meet the load.

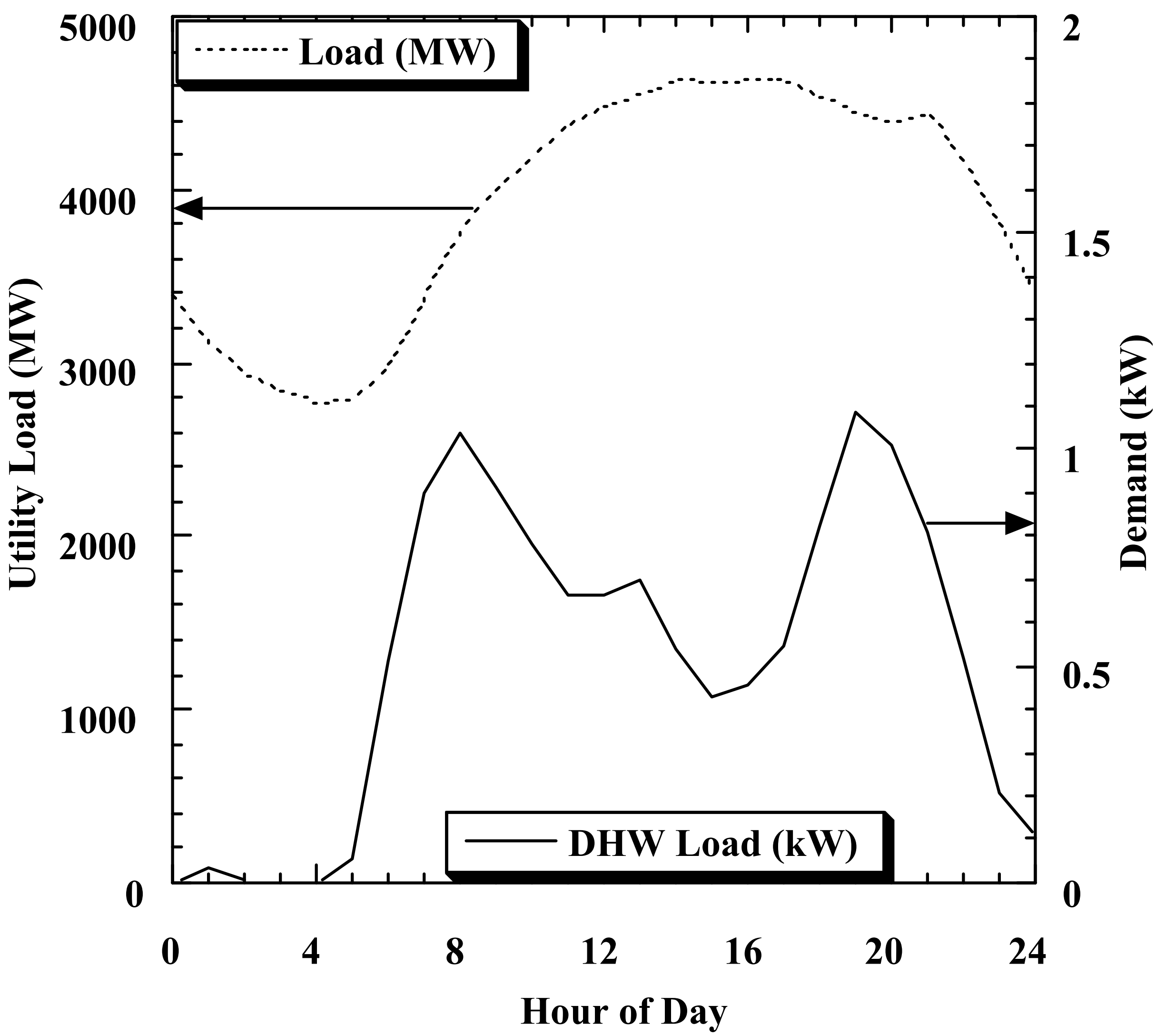


**Figure 5.4.1: Milwaukee, WI August 29th, 1991:**
**WEPCO Utility Load vs. Average Electric DHW for One Household**

The pollution information from Table 5.4.1 was multiplied by the heating value of the fossil fuel, to obtain the rates of emission in (lbs of pollutant per MWh) listed in Table

5.4.2. The new values can be used to translate each kWh of electricity into a mass of each pollutant. The relative environmental impacts of various DHW (solar, gas, and electric) can thus be quantified and evaluated with the monetized environmental externality values listed in Table 2.2.3. The tables for all Wisconsin utilities are found in the Appendix. Some typical pollutant rates for various types of generating sources are shown in Table 5.4.3.

**Table 5.4.3: Typical Efficiencies & Emissions of Various Forms of Power Generation (Flavin, 1994, p. 101)**

| Technology | Conversion Efficiency | Emissions | | |
|---|---|---|---|---|
| | | $NO_X$ | $SO_2$ | $CO_2$ |
| | (%) | (#/MWh) | | |
| Pulverized Coal-fired Steam Plant (w/o scrubbers) | 36 | 2.84 | 37.92 | 1949 |
| Pulverized Coal-fired Steam Plant (w/ scrubbers) | 36 | 2.84 | 1.90 | 1949 |
| Fluidized Bed Coal-Fired Steam Plant | 37 | 0.93 | 1.85 | 1898 |
| Integrated Gasification Combined-Cycle Plant (coal gasification) | 42 | 0.24 | 0.66 | 1671 |
| Phosphoric Acid Fuel Cell (Using Hydrogen reformed from natural gas) | 36 | 0.09 | 0.00 | 1122 |
| Aeroderivative Gas Turbine | 39 | 0.51 | 0.00 | 1036 |
| Combined Cycle Gas Turbine | 53 | 0.22 | 0.00 | 761 |

## 5.5 CCI Calculation

Most cost analysis schemes for comparing demand side management options compare only peak day demand reduction. There are values for energy, demand and emission reduction, but there is an additional value for reliable capacity (being able to meet the nominal peak). Capacity value is complicated, involving what one is willing to pay to have the equipment around and on standby if needed to meet demand on a peak day even if it is not actually used. 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 (e.g., coincidence with peak of solar versus wind argument). Complicating it even more is that this capacity value is time of day dependent. For most utility load forecasting analysis, twenty different peak days are required to test the reliability of a system.

The Capacity Contribution Index is discussed in Section 2.1.4. 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, 1994). The CCI values for each hour of the year sum to equal one:

$$\sum_{n=1}^{8760} CCI_{HOURLY} = 1 \qquad \textbf{5.5.1}$$

There is an added value to options that can reliably contribute energy or reduce load on peak days. To calculate the relative (to a conventional system) CCI value of a demand side option, such as a solar DHW system, the Contribution to Capacity Index is evaluated:

$$\sum_{\mathrm{n=1}}^{8760} \text{Individual System } \mathrm{CCI_{hourly}} = 1 - \left[\frac{\text{Actual SDHW Load}}{\text{Maximum Possible (DHW Load)}}\right] * \text{Utility Load } \mathrm{CCI_{hourly}} \qquad \textbf{5.5.2}$$

This CCI value of the solar DHW system can then be compared to that of a combustion turbine, its "peak clipping" competitor. A gas combustion turbine has a 100% availability since it is able to operate at its rated capacity whenever needed. 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 in Figure 5.5.1 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. Hours that the utility system is stressed the most are valued closer to one. Values where the system has excess capacity are valued at zero. The CCI method distributes the value of meeting capacity over the thirty to forty hours. This method is much more predictive of each power plant’s reliable contribution to capacity then extreme analyses that consider only at one peak hour of the year. The 1991 CCI values for the state of Wisconsin utility system are shown in Figure 5.5.1. The hour 5752, 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 value of solar contribution to capacity during that hour of the year has the most value compared to all other hours of the year.

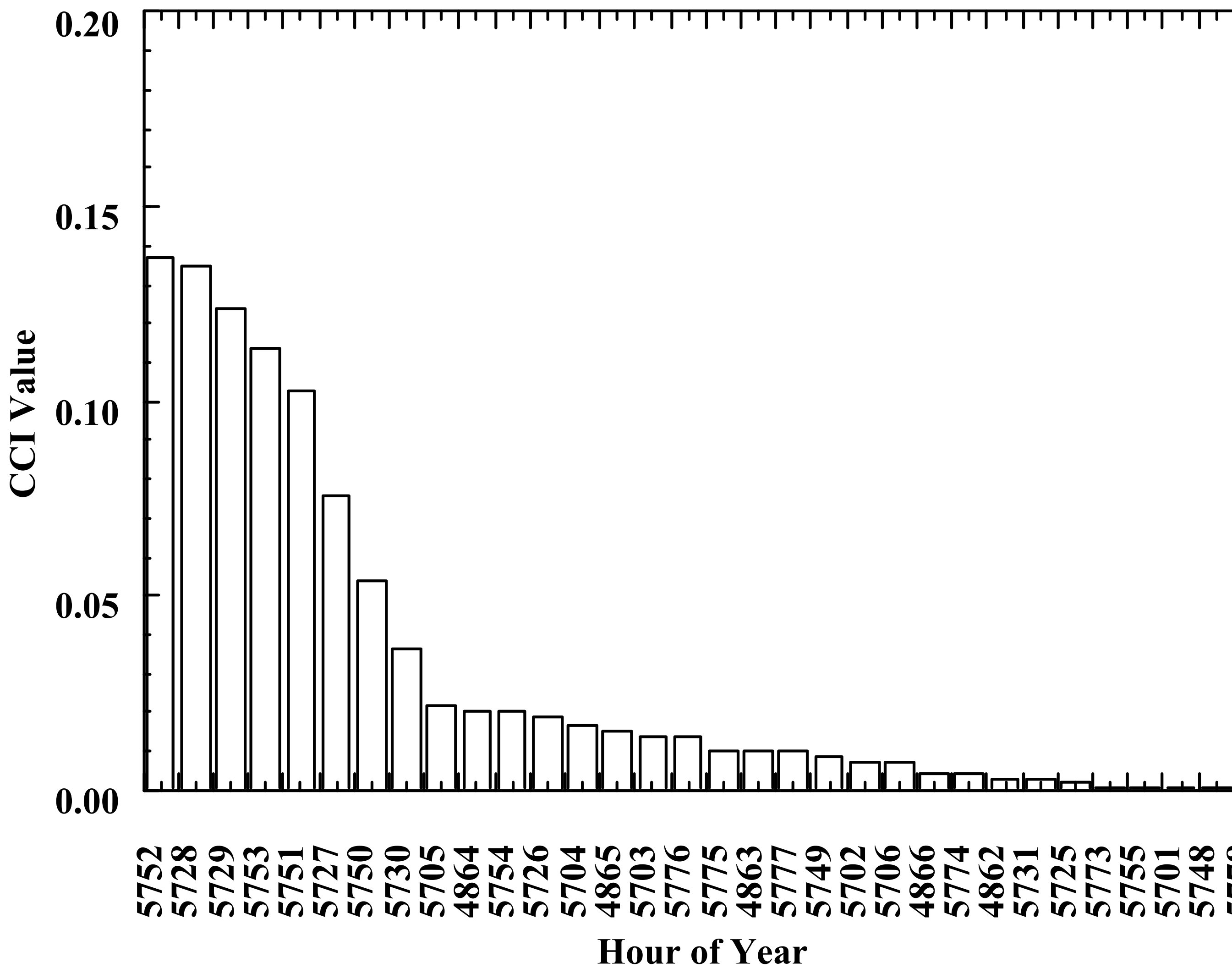


**Figure 5.5.1: Peak (only) CCI Values of 1991**

## 5.6 Cost Analysis

Two distinctly different perspectives of the costs and benefits of large scale replacement of conventional DHW systems with solar DHW systems are analyzed. Solar DHW systems can be analyzed from both supply-side and demand-side viewpoints. Both analyses consider lifetime energy, demand, emission, and capacity considerations.

### 5.6.1 Supply-Side Utility Cost Perspective

Marginal cost analysis alone (basically 8760 hours times the relative (to a combustion turbine) power generation and emission savings, without initial cost considerations) is a traditional approach for evaluating solar energy system savings. 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 and emissions. 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.

> Screening curve analysis is typically used in supply-side planning as a means of eliminating supply alternatives which are more costly than other alternatives from further study. Screening curves are used to compare the competitive position of new, modified, or retrofitted technology alternatives against each other. (PSCW, 1994)

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, LCC, 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 ($/kWh) cost per unit of electricity. The real levelized cost ($/kWh) can be performed with and without emission monetization. Some typical costs for electric power generation are shown in Table 5.5.1 (see Chapter 6.6: Utility Savings - Real Levelized Costs for the results for Wisconsin).

**Table 5.5.1: Cost of Electric Power Generation in the U.S.**
**(Flavin,1994 page 251, Table 12-2)**

| Technology | 1985 | 1994 | 2000 |
|---|---|---|---|
| | (1993 cents per kWh) | | |
| Natural Gas | 10-13 | 4-5 | 3-4 |
| Coal | 8-10 | 5-6 | 4-5 |
| Wind | 10-13 | 5-7 | 4-5 |
| Solar Thermal | 13-26 | 8-10 | 5-6 |
| Nuclear | 10-21 | 10-21 | * |

Solar thermal with back-up fuel, natural gas. * No nuclear power plant has been ordered since 1978. All orders since 1973 have subsequently been canceled.

## 5.6 Participant Cost Perspective

For the customer perspective cost analysis, the solar DHW systems are initially purchased by the utility as part of a demand-side management program 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 solar DHW 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.

The life cycle savings LCS of a solar DHW system can be calculated from the $P_1$, $P_2$ method (Duffie, 1991):

$$\mathrm{LCS} = \mathrm{P_1} * \mathrm{C_{F1}} * (\mathrm{E_{saved}}) - \mathrm{P_2} * \mathrm{Cost_{installed}} \qquad \textbf{5.6.1}$$

$$\text{Monthly Bill Impact} = \frac{\mathrm{LCS}}{12} * ((\mathrm{A/P}),\ \mathrm{d},\ \mathrm{N})$$

$$\text{where } ((\mathrm{A/P}),\ \mathrm{d},\ \mathrm{N}) = \left(\frac{\mathrm{d}(1+\mathrm{d})^{\mathrm{N}}}{(\mathrm{d}+1)^{\mathrm{N}} - 1}\right) \qquad \textbf{5.6.2}$$

The $P_1$, $P_2$ economic method combines many economic parameters. $P_1$ is a the ratio of the life cycle fuel cost savings, while $P_2$ is the ratio of the life cycle expenses. $P_1$ function of the discount rate, fuel inflation rate and analysis time period. $P_1$ spreads the operating costs for one year over the lifetime of the solar DHW system and brings them back to the present year:

$$P_1 = PWF(N, i_{fuel}, d) \quad \textbf{5.6.3}$$

where $$PWF(N, i_{fuel}, d) = \sum_{j=1}^{N} \frac{(1+i)^{j-1}}{(1+d)^j} = \frac{1}{(d - i_{fuel})}[1 - (\frac{1+i_{fuel}}{1+d})^N] \quad \textbf{5.6.4}$$

$i_{fuel}$=fuel inflation rate, d=discount factor, N=SDHW lifetime

$P_2$ is more complex, involving depreciation taxation, loan payments and installation costs. If the utility purchases the system and charges the customer monthly payments, only the purchase price of the system relevant ($P_2$ =1). The LCS can be applied over the fifteen year lifetime in monthly payments to determine if the customer would have a positive cash flow (utility bill savings) each month. The amount of savings or costs each month can be determined by a capital recovery factor analysis:

$$\text{Monthly Bill Impact} = \frac{LCS}{12} * ((A/P),\ d,\ N)$$
$$\text{where } ((A/P),\ d,\ N) = (\frac{d(1+d)^N}{(d+1)^N - 1}) \quad \textbf{5.6.5}$$

Determination of utility rebate is based on avoided generation costs and peak demand reduction credit. The WCDSR 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 5.6.1. WCDSR considers the values in the table the avoided energy costs at the generator and avoided capacity costs for generation. The avoided costs for demand include reductions in investment in new electric transmission and distribution facilities. The Summer Peak Demand will be used for rebate purposes, but hourly emissions were calculated for all hours of the year, so the emissions values in Table 5.6.1 are for reference purposes only. Three levels of emission monetization (from Table 2.2.3) are considered for this thesis: zero, PSCW values, and highest published values.

**Table 5.6.1: Avoided Cost Values Used by WCDSR (1994)**
**(On-peak means 9 a.m. to 9 p.m. during weekdays. )**

| Description Time Period | Avoided Costs (w/ $S0_2$ Emissions) | Avoided Costs (w/ $SO_2$ & Greenhouse Gas emissions) |
|---|---|---|
| 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 |