Electric Utility Interest in Solar Energy Systems

by

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CHAPTER 1

Introduction

Electric utilities can realize economic and environmental benefits from a large scale implementation of solar energy systems. Reductions in energy use achieved with solar domestic hot water (SDHW) systems and energy generation from photovoltaic (PV) systems at the consumer level result in reductions in energy, emissions and demand at the generation level, and improvements in system reliability through capacity contribution. Additional utility benefits can be found in delaying power plant construction, electric customer retention and government incentives such as tax credits given for equipment investment and energy subsidies.

These benefits can be quantified in terms of dollars to give a utility an assessment of the value that a large scale implementation of solar energy systems may have. Starting in the late 1980's the Sacramento Municipal Utility District (SMUD) offered customers rebates on SDHW systems to encourage the use of solar energy. Not only did this program offer a rebate off the total cost of the SDHW system, but it spread the balance out in payments over ten years. Recently, Wisconsin Public Service (WPS) began a program in which customers could lease a $2000 SDHW system for $140 down and $12 per month.

It is important to show electric customers that such solar energy demand-side

management (DSM) programs have value to them. Historically, homeowners have tended to shy away from SDHW systems due to high first costs, perceived unreliability of the systems and payback periods on the order of ten or more years. Such programs as offered by SMUD and WPS help ease the burden of payment by the customer for solar energy systems. Moreover, annual electric bill savings outweigh the annual payments for the system, thus making SDHW attractive to consumers.

1.1 Motivation for Research

For a utility to consider solar DSM programs such as those offered by SMUD and WPS, the programs must be beneficial to the utility. Central Vermont Public Service Corporation attempted to assess system performance by an on-site monitoring of ten SDHW test systems (Sinos, Lind and Kirby, 1995). This type of small scale monitoring shows the consumer what their energy savings are, but shows insignificant impact at the utility level. Utilities must look at a larger number of systems to assess the benefits that solar energy systems can have.

Most utility analyses of solar energy systems stop at an assessment of energy reduction. These assessments are usually based f-chart predictions (Duffie and Beckman, 1991) of monthly performance and are based on average temperature and radiation values for the given month. This method predicts aggregate energy reduction reasonably well, but it does not identify emission and demand reductions.

Utility analyses that attempt to address the demand reduction achieved by solar options tend to look at the system performance on a single peak day or a group of peak hours. This method fails to account for capacity contribution through demand reductions

at all hours (Harsevoort and Arny, 1994). An hourly study of these capacity contributions is needed to accurately assess the improvements in system reliability. Furthermore, operating costs and emission characteristics are dependent on the last plant to be added to the generation mix, known as the marginal plant. Operating costs and emission characteristics are therefore time dependent as the marginal plant varies with time.

An accurate analysis of the impact of solar energy systems must be an annual assessment performed on an hourly basis. System performance is calculated using hourly weather data for the city in which the utility's customers are located. The marginal plant for a given utility or group of utilities is calculated hourly with utility or region load information and plant capacity data for each plant in the regional mix. With hourly predictions of both system performance and the marginal plant, an accurate assessment of energy, emissions and demand reductions can be made.

It is of vital importance to the correctness of the analysis that weather data and the load data represent the same year. Both the utility load and the performance of solar energy systems are largely driven by weather and the interaction is often well matched. For summer peaking utilities, the peak load is often found on the hottest day of the year that is accompanied with high levels of solar insolation. Winter peaking utilities in areas where homes are heated by electric means tend to find peak loads on the coldest day of the year. In northern climates, these peak load days are often clear days with high solar insolation which follow clear nights. With these peak load observations, the weather-load interaction is seen and the importance of using weather and load data from the same year in an analysis becomes apparent.

A large number of systems must be considered for the analysis to have a

significant impact on an electric utility. When considering photovoltaic systems as grid-connected electric generators, the performance of many systems as seen by a utility at the generation level can be reasonably assessed by simulating a single system as an average system and scaling up the results. However, this method is not accurate when simulating a large number of SDHW systems.

The impact of a large scale implementation of SDHW systems cannot be estimated by one test site system. SDHW systems will not act identical to one another due to storage and control differences and, most importantly, differences in water draw profiles at individual locations. To assess the impact of many SDHW systems with one simulation an appropriate average water draw must be used. This average water draw can then be used in a simulation to predict the amount of energy required to heat the mains temperature to a set point temperature and ultimately to predict the amount of energy required at the electric utility generation level. With an appropriate average water draw, a single average SDHW simulation may be used in conjunction with the energy rate control (ERC) simulation method to predict the impact of many SDHW systems (Cragan, 1994).

1.2 Literature Review

Grater (1992) showed that annual energy consumption of a single solar domestic hot water system was less than that of an electric domestic hot water (EDHW) system, but peak demand was the same in both cases. Grater then simulated multiple EDHW and SDHW systems using random hot water draw profiles for each pair of simulations. Through these multiple simulations Grater showed that not only was the SDHW energy consumption less than that of the EDHW systems but, also, the SDWH systems showed

lower peak demand. Grater concluded that a sample size of 400 systems is adequate to predict a large scale impact of SDHW systems. The problem with Grater's analysis was the use of extreme and unlikely water draw profiles in some cases.

Warren (1993) addressed the issue of sample size in a study of gas furnaces. Warren showed that a sample size of 100 systems provides adequate confidence in determining the average demand of an ensemble of systems as compared to the average demand of measured data. Warren then explored a single energy rate control (ERC) using average system parameters as an alternative to a large number of temperature level control (TLC) simulations. Warren found the ERC simulation to closely reflect the average of greater than 1000 TLC simulations.

Cragan (1994) combined the ideas of energy rate control and an average hot water draw profile to assess the impact on a utility of an ensemble of SDHW systems. Cragan developed average weekday and weekend hot water draws using WATSIM, a program that predicts typical household hot water draws, developed by the Electric Power Research Institute (EPRI). Cragan showed that the use of an average water draw resulted in a good estimate of average system performance. Cragan analysis employed the energy rate control to simulate the demands required by SDHW and EDHW systems to supply the hot water required by the developed water draws. The results were compared to assess energy, emission and demand reductions at the generation level provided by the ensemble of SDHW systems.

1.3 Objective of Research

The lack of a standard planning model that evaluates the benefits and costs of

renewable technology is a significant barrier to utility integration of these technologies (Wan and Parsons, 1993). This research aims to develop a standard methodology to assess the benefits and costs of solar domestic hot water and photovoltaic systems to utilities and electric customers. Advantages and disadvantages of a solar DSM program are identified.

The objective is extended to automate the methodology into a software package to be distributed to utilities so that any given utility can assess the benefits found in solar energy systems. Innovative use of TRNSYS (Klein et al., 1994), a software package developed by the University of Wisconsin-Madison Solar Energy Laboratory, and TRNSED (Fiksel et al, 1994), an editing environment to TRNSYS, allow users to select and and tailor solar energy systems to be used in the analysis. Users have the opportunity to provide specific utility information that will affect the economic assessments.

TRNSYS is used to simulate conventional and solar energy system performance. Subroutines added to the TRNSYS program allow for calculation of the marginal plant at each hour of the year and the economics of a given option. Given system performance, marginal plant data and user specified information, reductions in demand at the consumer level are translated to reductions in energy, emissions and demand at the generation level and quantified in terms of dollars. These savings are then combined with other identified benefits to report the life cycle savings of a solar energy option.

CHAPTER 2

Background

A utility load is largely driven by weather that is often well matched with the operation of solar energy systems. Most utilities tend to find peak loads in the summer. These peak loads are largely driven by air conditioning demands and are on hot days with high levels of solar insolation. These conditions are ideal for solar energy system operation. With a sufficient number of solar energy systems on the demand side, a utility can achieve a significant demand reduction.

Some winter peaking utilities can also realize demand benefits from solar energy systems. Utilities that peak in the winter tend to be in areas where homes are generally heated electrically. Peak loads are often found on the coldest day of the year when heating demands are highest. In northern climates, the peak loads tend to be on clear days following clear nights. These clear days allow for significant solar insolation that promote solar energy system performance.

Summer and winter peaking utilities can both benefit from the energy and emission reductions at the generation level. A large scale implementation of solar energy systems can provide for significant annual reductions in energy use at the consumer level resulting in annual energy and emission savings at the generation level. These benefits along with the demand benefits can make solar energy systems an attractive demand-side

management option.

2.1 Solar Energy Systems

Two types of solar energy systems are often considered for home use: photovoltaics and solar domestic hot water. Photovoltaic systems convert solar radiation to electricity. These systems can be connected to the grid to act as a small power plant. Solar thermal systems use solar insolation to heat a medium such as air or water. SDHW systems are a type of solar thermal system and are can be considered as a small power plant in the sense that they reduce electric demand.

2.1.1 Solar Domestic Hot Water

Solar domestic hot water systems are used to preheat water that is to supply a hot water load. The primary elements in an SDHW system are a solar collector, an auxiliary tank with an auxiliary heating element, a pump and a controller. Other common components include a heat exchanger and and a solar storage tank. Figure 2.1.1-1 depicts a typical two-tank solar energy system.

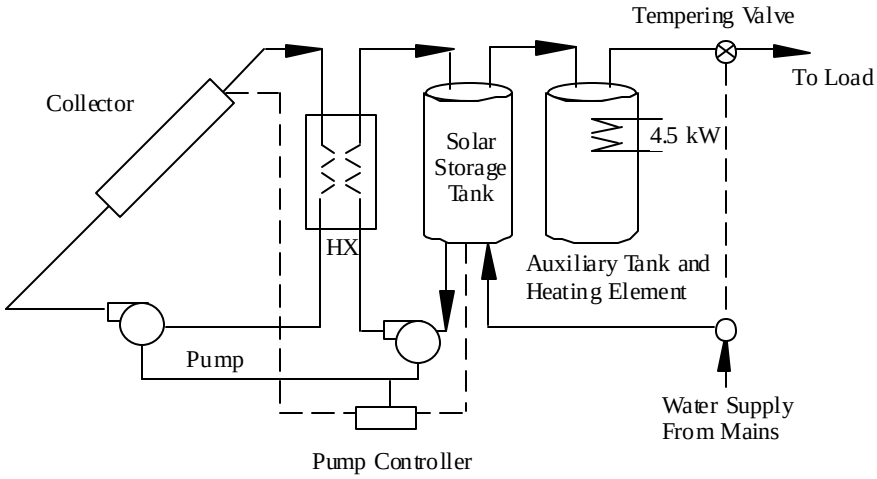

Figure 2.1.1-1: A Typical SDHW System

In this system the auxiliary heat input is a typical 4.5 kW electric heating element. The heating element makes up for the energy not provided by the solar system to meet the set point temperature of the water to be delivered to the load. The pump controller monitors the temperatures at the bottom of the solar storage tank and at the outlet on the collector plate. When the plate temperature reaches a temperature above that of the bottom of the tank, the pump turns on, collecting useful thermal energy.

At times the system will collect sufficient energy so that no auxiliary heat input is required. In summer it is not uncommon to find the temperature of the solar heated water to exceed the set point temperature. In this case the water is tempered via the tempering valve as shown in figure 2.1.1-1. The result is that the water draw out of the auxiliary tank is less than that delivered to the load.

The heat exchanger is a common feature in cold climates used for freeze protection. Without a heat exchanger the water from the storage tank is pumped through the collector. Under freezing conditions, water in the lines can freeze causing damage to the system. Ethylene glycol-water and propylene glycol-water solutions are the most common anti-freeze heat exchanger fluids used in SDHW applications. Another form of

freeze protection is known as drain-back. In a drain-back system, the water that would remain in the lines is drained into the tank or a sump to keep it from freezing (Duffie and Beckman, 1991).

2.1.2 Photovoltaics

Photovoltaic systems are used to convert solar energy into electrical energy. The primary components of a grid-connected photovoltaic system include a photovoltaic panel, a maximum power point tracker and a DC/AC converter. The photovoltaic panel is made up of may individual photovoltaic cells connected in series. Figure 2.1.2-1 illustrates a typical grid-connected photovoltaic system.

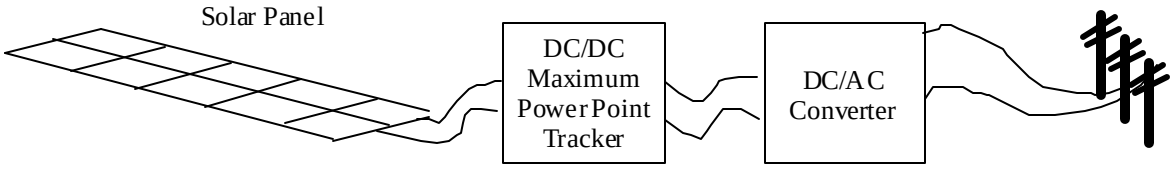

Figure 2.1.2-1: A Typical Grid-Connected Photovoltaic System

The rudimentary physics behind the photovoltaic process is that an atom or molecule of the material that makes up the cell absorbs a photon of the solar radiation. If the energy level of the photon is high enough, the absorption of the photon frees an electron from the atom or molecule. This process of freeing electrons ultimately results in the electricity produced by a PV cell. Common materials used in photovoltaic cells are silicon, cadmium sulfide and gallium arsenide (Duffie and Beckman, 1991).

The current and voltage characteristics of a photovoltaic cell changes as the level of incident radiation changes. Figure 2.1.2-2 displays the trends of the I-V curves for a

typical photovoltaic cell for changes in radiation level and is intended for illustration purposes only. Figure 2.1.2-2 shows that as the incident radiation level increases higher currents can be achieved. Many operation points are possible for a given radiation level. However, it is most desirable to operate at the maximum power point for a given incident radiation level, marked by an 'X' in figure 2.1.2-2.

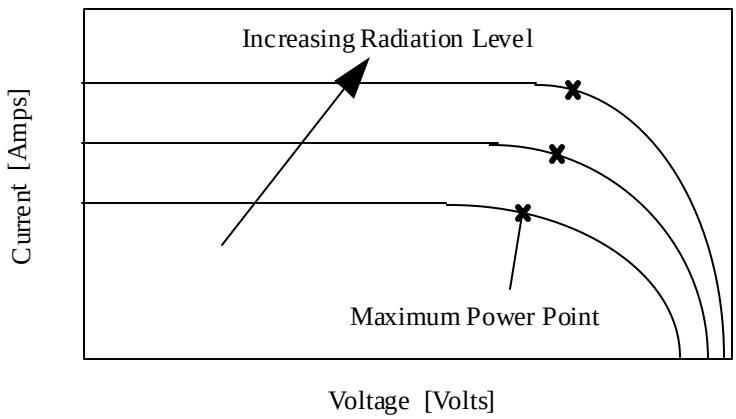

Figure 2.1.2-2: I-V Curve for a Typical PV Cell

The DC current drawn from the photovoltaic cell is fed to a DC/DC maximum power point tracker. The maximum power tracker varies resistance to maintain a near optimum operating condition. In most cases the maximum power tracker also converts the power to correspond to the voltage that is required by the load. The resulting voltage-corrected power is fed through a DC/AC converter where the DC current is converted to an AC current with a frequency and voltage matching that of the grid.

2.2 Electric Utility Interest in Solar Energy Systems

Utilities considering a solar DSM program must identify the potential benefits and costs of the option. Costs related to such a program include the initial investment required to purchase the systems, administrative costs and any operation and maintenance

costs that may be associated with the systems. Generally there is no operation costs to the utility associated with solar energy systems as the customers pay for the energy required to run the systems.

Solar energy systems offer benefits such as reductions in energy, emissions and demand. Reductions in energy achieved by SDHW systems and the energy generated by PV systems at the customer level directly result in these benefits at the generation level. Other benefits may be found in government incentives offered to promote renewable energies. These incentives include tax credits given towards the investment in renewable energy and a subsidy given for energy production by the system.

It is up to the utility to place other values on the program. For example, a utility may include customer retention as a benefit of a solar DSM program. It is possible that an electric utility may lose electric customers to an alternate fuel such as natural gas for water heating. With a solar energy program, a utility may retain a portion of these customers that would otherwise be lost. Additionally, solar energy programs may bring in new customers, capturing a larger market. Utilities that deal in both electricity and gas may want to consider customer retention as a benefit as a higher profit margin is often realized on electricity than on natural gas.

Utilities may also consider placing value on delayed power plant construction. Solar energy systems effectively add capacity to a utility's generation mix. The effective capacity added by solar energy systems may be significant enough to delay the construction of new facilities. This can be viewed as taking further credit for peak demand reduction. Once the potential benefits of a solar DSM option are identified, they can be quantified.

CHAPTER 3

Solar Energy and Conventional System Models

To evaluate the impact of a large scale implementation of solar energy systems on an electric utility, knowledge of solar system performance is needed. This chapter develops the system models used to simulate a large number of solar energy systems. The intent is to represent the results of a large number of simulations with a single simulation. From the solar system models, the system performance can be predicted. The system performance is used to evaluate energy, emission and demand reductions at the generation level.

The transient system simulation program TRNSYS (Klein et al., 1994) developed by the University of Wisconsin Solar Energy Lab is used to simulate solar energy system performance. TRNSYS is a modular program that contains subroutines known as TYPES that represent the components found in solar energy systems among others. By correctly specifying the time dependent inputs and fixed parameters that define each TYPE, the solar energy systems are simulated.

Certain parameters of the solar energy and conventional system models can be edited through TRNSED (Fiksel et al., 1994). The sections describing the system models are concluded with a discussion of the parameters that can be edited. Default values are given as typical system parameters.

3.1 Domestic Hot Water Systems

Average system demands of both SDHW and EDHW systems are found in order to evaluate the impact that a large scale implementation of SDHW systems has on an electric utility. Utilities realize reductions in energy, emissions and demand due to the performance of an ensemble of SDHW systems. A representative EDHW system is needed as a comparative system to judge SDHW system performance against. An average residential water draw is obtained to predict the average amount of energy required by the SDHW and EDHW systems.

3.1.1 System Configurations

Typical EDHW and SDHW models are developed using TRNSYS. One and two tank SDHW systems are modeled to assess their performances compared to an EDHW system. Certain system parameters are made visible through the TRNSED front-end. Representing one and two tank models through TRNSED allows for a wide variety of systems to be simulated as system parameters can be changed.

3.1.1.1 Electric DHW System Model

The EDHW system model is depicted in figure 3.1.1.1-1. The system consists of a electric hot water storage tank with two 4.5 kW heating elements. The tank supplies a residential hot water load. Water from the mains replaces the water drawn from the tank to supply the load. To simulate stratification, the storage tank is modeled as a three node tank, representing three temperature levels within the tank. A heating element is located in both the top and bottom third of the tank. The heating elements are controlled on a master/slave relationship. With this control, only one element may be on at a given time so that the maximum power demand is 4.5 kW. This arrangement is typical of standard EDHW systems.

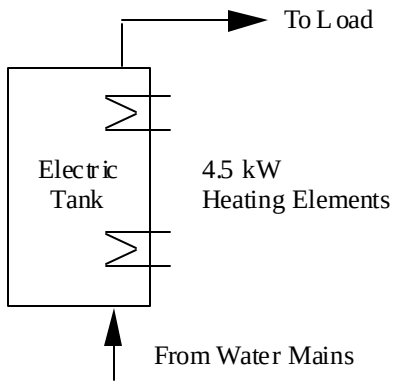

Figure 3.1.1.1-1: The EDHW System Model

The EDHW system supplies hot water at a given set point temperature. The set point temperature used in the EDHW model is 140¡ F (60¡ C). The set point temperature is a fixed system parameter. The heating element supplies electric power to maintain the upper third of the tank at the set point temperature.

System parameters can be changed through the TRNSED front-end. The tank parameters available in the TRNSED front-end are the volume and height, and the insulation R value. The magnitude of the average daily water draw can also be changed (see section 3.1.2). These parameters are made available so that a system can best be represented for a given location. Table 3.1.1.1-1 summarizes default parameters typical to an EDHW system. The tank parameters are taken from the SRCC ratings (SRCC, 1994).

8/6/2002**Table 3.1.1.1-1: Typical EDHW System Parameters**

Tank Parameters

Tank Volume
80 [gallons]
Tank Height
4.89 [ft]
Insulation R Value
16.7 [hr-ft^2-F/Btu]

Water Draw Parameters

Average Daily Water Draw
69 [gallons/day]

17

3.1.1.2 One Tank SDHW System Model

The one tank SDHW system model is depicted in figure 3.1.1.2-1. The system consists of a collector, auxiliary tank with a 4.5 kW heating element, pump and controller. The heating element in the auxiliary tank provides heat input that is not provided by the solar collector to maintain the upper third of the tank at the set point temperature of 140¡ F. The bottom heating element of the tank is disabled, leaving only the top element. The controller initiates flow through the collector by monitoring the temperatures at the bottom of the tank and at the collector outlet.

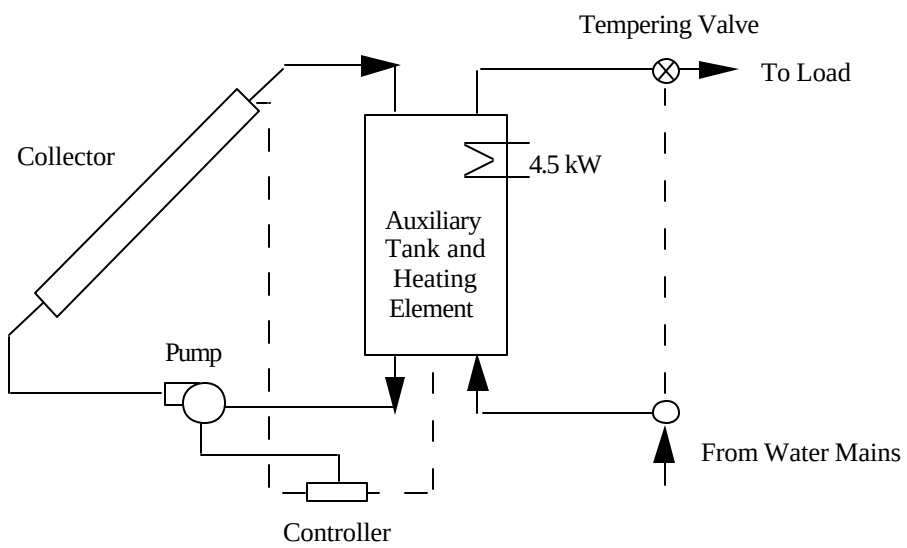

Figure 3.1.1.2-1: The One Tank SDHW System Model

A tempering valve is introduced to the system in case the tank temperature is above the set point temperature. If the tank temperature is above the set point, the tempering valve mixes mains water with the water from the tank, thus reducing the draw from the tank. The new tank draw can be found with mass and energy balances on the tempering valve, assuming a constant specific heat of water. Equation 3.1.1.2.1 gives the

water draw from the tank when the tank temperature is above the set point temperature.

mass balance:

$$m_{tank} + m_{mains} = m_{load}$$

energy balance:

$$m_{tank} c_p T_{tank} + m_{mains} c_p T_{mains} = m_{load} c_p T_{set\ point}$$

Rearranging and substituting for m_{mains} *:*

$$m_{tank} = m_{load} \left[\frac{T_{set\ point} - T_{mains}}{T_{tank} - T_{mains}} \right] \qquad (3.1.1.2.1)$$

System parameters can be changed in the TRNSED front-end. The tank parameters and magnitude of the water draw can be specified, as in the case of the EDHW system (see section 3.1.1.1), as well as the solar collector parameters. Solar collector parameters accessible through the TRNSED front-end include the number of collectors that make up the system, collector area, slope, $F_R(\tau\alpha)$ and $F_R U_L$. A heat exchanger, as depicted in figure 2.1.1-1, can also be added to the system through TRNSED. The heat exchanger parameters that can be modified are the heat exchanger effectiveness and the specific heat of the collector side fluid. A typical heat exchanger effectiveness is 0.5 or less. The specific heat of ethylene glycol, a typical collector side fluid used with a heat exchanger is 0.577 Btu/lbm-F. If no heat exchanger is desired, the effectiveness is entered as -1. The pump size is specified by entering the power consumption of the pump in Watts. Table 3.1.1.2-1 summarizes default parameters typical to a one tank SDHW system. Collector parameters are typical to an SRCC rated collector.

8/6/2002Table 3.1.1.2-1: Typical One Tank SDHW System Parameters

nk Parameters

ank Volume
[gallons]

ank Height
9 [ft]
ısulation R Value
.7 [hr-ft^2-F/Btu]
lar Collector Parameters

umber of Collectors in Array

rea
[ft^2]
$_R(\tau\alpha)$
)
$_R U_L$
.9 [Btu/hr-ft^2-F]
lope
[degrees]
at Exchanger Parameters

ffectiveness

pecific Heat of Collector Side Fluid
) [Btu/lbm-F]
mp Parameters

umping power
[W]
ater Draw Parameters

verage Daily Water Draw
[gallons/day]

3.1.1.3 Two Tank SDHW System Model

The two tank SDHW system model is depicted in figure 3.1.1.3-1. The system consists of a collector, solar storage tank, auxiliary tank with a 4.5 kW heating element, pump and controller. The auxiliary tank provides heat input that is not provided by the

collector to supply the load at the set point temperature of 140¡ F. The bottom heating element of the tank is disabled, leaving only the top element. The controller initiates flow through the collector by monitoring the temperatures at the bottom of the tank and at the collector outlet. The tempering valve operates in the same manner as described in the one tank SDHW model.

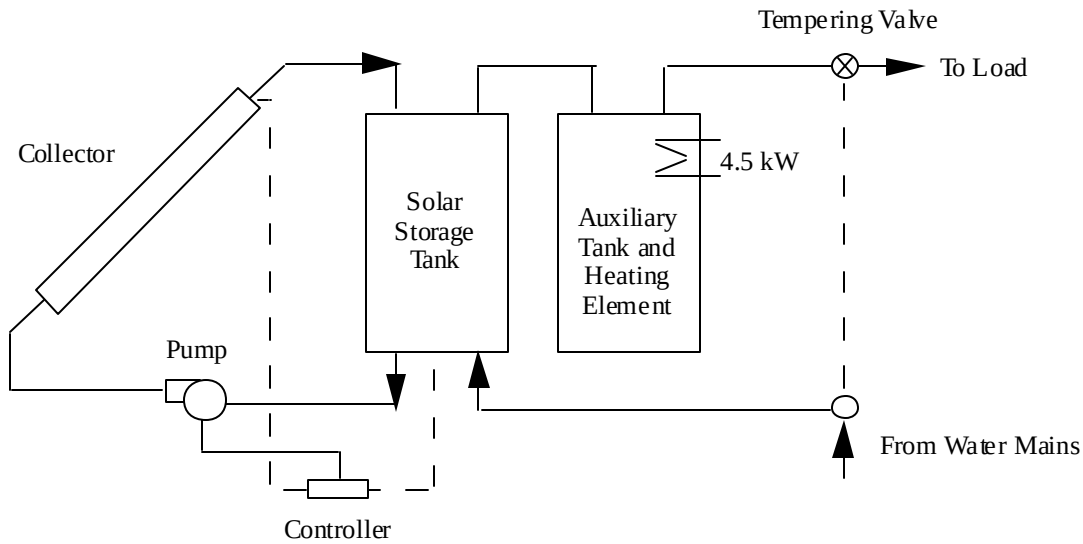

Figure 3.1.1.3-1: The Two Tank SDHW System Model

System parameters can be changed through the TRNSED front-end. The parameters that can be altered are the same as in the one tank SDHW model with the addition of the solar storage tank parameters. A heat exchanger can be added between the collector and solar storage tank as described in the one tank model. Table 3.1.1.3-1 summarizes default parameters typical to a two tank SDHW system simulation.

8/6/2002**Table 3.1.1.3-1: Typical Two Tank SDHW System Parameters**

ıxiliary Tank Parameters

ank Volume
[gallons]
ank Height
9 [ft]
ısulation R Value
.7 [hr-ft^2-F/Btu]

lar Storage Tank Parameters

ank Volume
[gallons]
ank Height
9 [ft]
ısulation R Value
.7 [hr-ft^2-F/Btu]

lar Collector Parameters

umber of Collectors in Array

rea
[ft^2]
$_R(\tau\alpha)$
)
$_R U_L$
.9 [Btu/hr-ft^2-F]
lope
[degrees]

at Exchanger Parameters

ffectiveness

pecific Heat of Collector Side Fluid
) [Btu/lbm-F]

mp Parameters

umping power
[W]

ater Draw Parameters

verage Daily Water Draw
[gallons/day]

3.1.1.4 Other System Configurations

Specialized TRNSED files offer the option to put SRCC rated collectors into the one and two tank models. By selecting an SRCC collector, the collector area,

$F_R(\tau\alpha)$, $F_R U_L$ and incidence angle modifiers are fixed in the simulation (SRCC, 1994). Use of SRCC rated collector parameters allows for assessing system performance using parameters of real solar collectors.

Other SDHW system configurations, such as photovoltaic pumps and thermosyphons, can be modeled with TRNSYS. With knowledge of TRNSYS, specific systems that are to be considered as solar DSM options can be simulated to assess system performance. Section 5.6 of the EUSESIA User's Manual (Trzesniewski et al., 1995) in Appendix A describes the considerations involved in modeling a system.

3.1.2 Residential Water Draw Representation

To simulate a large number of solar energy system with a single system, an average residential hot water draw must be obtained. This average draw may be thought of as the draw seen by a water utility due to residential hot water draws only. Figure 3.1.2-1 shows a typical family of four household water draw as predicted by WATSIM, a water simulation program (EPRI, 1992). Using this water draw as an average water draw would be incorrect as it would represent the water draw patterns of a single household. The water draw depicted in figure 3.1.2-1 is not the average load a water utility would see due to residential hot water draws.

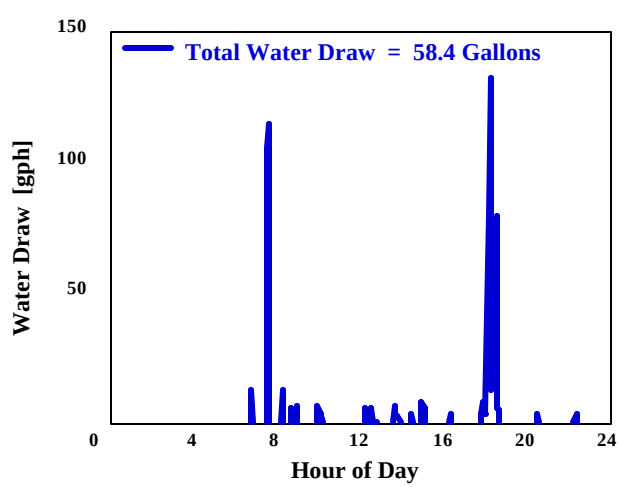

Figure 3.1.2-1: A Typical Household Daily Hot Water Draw (Cragan, 1994)

Cragan (1994) addressed the issue of finding an average water draw profile representative of residential hot water draws. Employing WATSIM, nine hundred separate household water draws, as the one shown in figure 3.1.2-1, were simulated. The resulting nine hundred profiles were averaged and smoothed to find average weekday and weekend water draw profiles. Figure 3.1.2-2 shows the resulting hot water draws that are used in the EDHW and SDHW system simulations. These draws result in an aggregate draw of approximately 69 gallons/day.

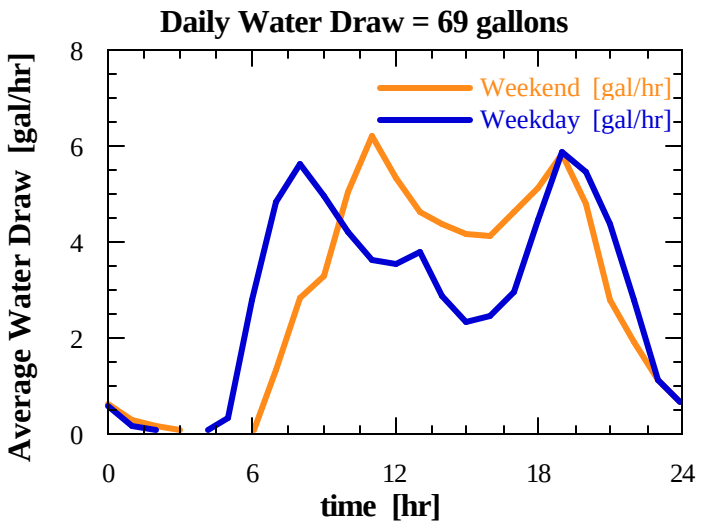

Figure 3.1.2-2: Average Weekday and Weekend Hot Water Draw Profiles

The water draw used in the domestic hot water systems can be scaled through the TRNSED front-end. The front-end offers an opportunity to specify the average daily water draw for a location. To scale the draw, the hourly value is multiplied by the value input in TRNSED and divided by the basis (69 gallons/day).

3.1.3 Critical Timestep Considerations

When simulating a domestic hot water system, care must be taken in defining the simulation timestep. A model that is simulated at a timestep greater than the critical timestep can go unstable. When simulating domestic hot water systems, the critical timestep can be reduced to a function of the volume of the tank (V_{tank}), the number of tank nodes (N) and the volumetric flow rates of any flow into and out of the tank. The flows through the tank are the flow due to the water draw (V_{draw}) and the flow to the collector ($V_{collecto}$) Equation 3.1.3.1 gives an expression for the critical timestep.

$$\Delta t_{critical} = \frac{V_{tank}}{N\left(V_{draw} + V_{collector}\right)} \qquad 3.1.3.1$$

In this simulation the tank size and magnitude of the water draws are parameters that can be changed in the TRNSED front-end. To correctly assign the critical timestep an extreme case is identified which yields the smallest critical timestep. Referring to equation 3.1.3.1 it can be seen that the critical timestep will be smallest when the tank volume is small and the draw from the tank is large. Two assumptions must be made to define the extreme case. First, it is assumed that the smallest tank size that will be simulated is a 40 gallon tank. Second, it will be assumed that the maximum flow rate to the load will be 10 gallons/hr. Referring to figure 3.1.2-2 it can be seen that a for a daily water draw of 69 gallons/day, the maximum draw is around 23 kg/hr (6 gallons/hr). Realistically, an average daily draw for an area would not be more than 100 gallons/day, which results in a maximum draw of around 9 gallons/hr. A maximum draw of 10 gallons per hour is chosen to add a safety factor into the critical timestep calculation.

The flow rate through the collector side of the tank is fixed at 86 gallons/hr (325 kg/hr) and the tank is modeled with three nodes. Using this fixed information along with the two assumptions previously discussed, the critical timestep can be found from equation 3.1.3.1. This evaluation results in a critical timestep of 0.139 hr. The critical

timestep chosen for the simulations is 0.1 hr, slightly less than the critical timestep. Table 3.1.3-1 summarizes the parameters used in determining the simulation timestep.

8/6/2002**Table 3.1.3-1: Parameters Used in Timestep Consideration**

nimum Tank Volume
[gallons]
mber of Tank Nodes
(fixed)
llector-Side Flow
[gph] (fixed)
ximum Tank Draw
[gph]
itical Timestep
.39 [hr]
nulation Timestep
. **[hr]**

25

3.1.4 Integrating the Demand for Hourly Output

The assessment of the impact of large scale implementation of solar energy systems is performed on an hourly basis. Thus, the system performance must be reported on an hourly basis. However, in order to meet critical timestep criteria, the simulation is run at a tenth of an hour timestep. To output the demand requirement of a DHW system on an hourly basis, the demand requirements at each timestep must be integrated over the hour in which they occur. This integration is done by sending the demand requirements of a system through the TRNSYS TYPE 24 integrator which is reset hourly. Table 3.1.4.-1 lists the hourly demand output from the DHW system models.

8/6/2002**Table 3.1.4-1: EDHW and SDHW System Hourly Model Outputs**

)HW Model
ux
)HW Model

ux + P_{pump}

A few words need to be said about assessing the heat input requirements of the system. Crag)94) used the energy rate control approach (ERC) where an just enough heat was input into the water draw of the load tantaneously raise it to the set point temperature. In this approach the heating element is assumed to have an infinite h e and tank losses are modeled as only from the top third of the tank which is assumed to be at the set point temperatu e required heat input is integrated over the hour.

The energy rate control approach is also used in the DHW models previously discussed, althougl not as apparent. The nature of the tank models in TRNSYS is essentially that of ERC except that the rate of input ıited to 4.5 kW rather than an infinite rate. As long as the integrated required heat input does not exceed 4.5 kW, t ıting element in the tank acts as an ERC zip heater. This approach is somewhat more accurate than the method used ıgan since the tank losses are not assumed, as in Cragan's work, and are correctly accounted for.

3.2 Photovoltaic Systems

To assess the performance of a PV system a model is developed to output the hourly electric generation of the system. Since the PV system generates electricity rather than reduces electricity consumption, no comparative system is needed in the analysis. Electricity produced by the PV system at the customer level is reflected in energy, emission, and demand reductions at the generation level.

Figure 3.2-1 depicts the PV system model used for simulation. The system consists of a photovoltaic array, a maximum power point tracker and a DC/AC converter. Electricity produced by the cell is fed to the maximum power point tracker which maximizes the power by selecting the appropriate operating voltage and current. The DC signal is then converted to an AC current and the signal is adjusted to the grid voltage and frequency through the DC/AC converter.

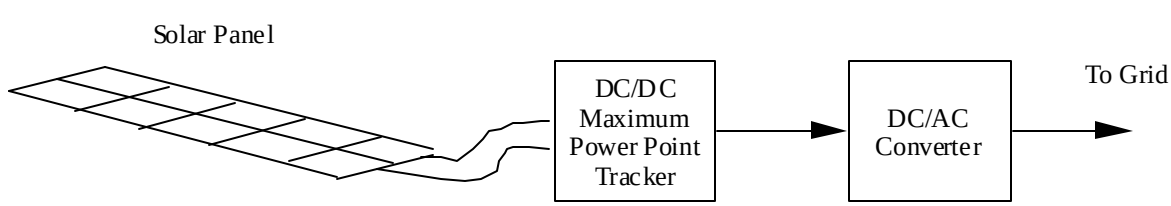

Figure 3.2-1: The PV System Model

A PV panel has parameters that are characteristic to its manufacturing and reference conditions. Parameters that define the I-V curve at reference irradiation and temperature conditions include the open circuit voltage (V_{oc}) and short circuit current (I_{sc}) and maximum power voltage (V_{Pmax}) and maximum power current (I_{Pmax}) as depicted in figure 3.2-2. The open and short circuit temperature coefficients ($\mu_{V,oc}$ and $\mu_{I,sc}$) are defined as the change in open circuit voltage and short circuit current with respect to temperature (dV_{oc}/dT and dI_{sc}/dT) respectively (Duffie and Beckman, 1991). Other parameters characteristic to the manufacturing of the panel include the transmittance-absorptance product ($\tau\alpha$), material band gap, number of individual cells in series per panel, panel width and panel length.

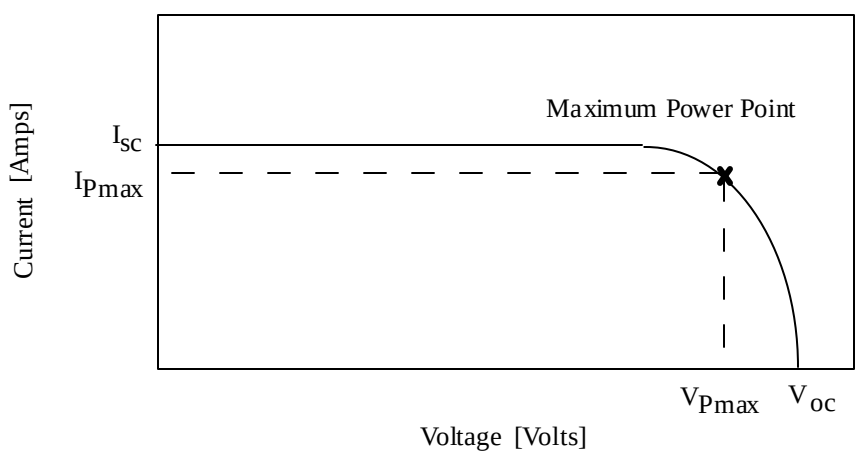

Figure 3.2-2: The I-V Curve at Reference Conditions

In the PV model these parameters are fixed through selection of specific manufactured panels. Table 3.2-1 summarizes the characteristic parameters of two such panels, the Advanced Photovoltaic Systems Inc. model EP-50 and the Solarmodule model AEG PQ.

8/6/2002 **Table 3.2-1: PV Panel Parameters**

nufacturer and Model

vanced Photovoltaic Systems Inc. EP-50
armodule AEG PQ
ference Irradiation
00 [W/m2]
00 [W/m2]
f. Cell Temperature
8 [K]
8 [K]
at Reference
[Amps]
1 [Amps]
c at Reference
5 [Volts]
4 [Volts]
ax at Reference
2 [Amps]
[Amps]
max at Reference
[Volts]
45 [Volts]
sc
015
014954
,oc
19425
090092
)
)
)
terial Band Gap
55
55
Cells in Series per Panel

nel Width
[m]
6 [m]
nel Length
25 [m]
76 [m]

The PV system can be changed in the TRNSED front-end. The number of

collectors that make up the system and their slope can be specified through TRNSED. Power is lost in both the maximum power point tracker and the DC/AC converter. The efficiency of these two components can be specified through the front-end. The grid operating voltage can also be specified in the TRNSED front-end. Table 3.2-2 summarizes default parameters typical to a PV system.

8/6/2002Table 3.2-2: Typical PV System Parameters

' Panel System Parameters

umber of panels in series

umber of panels in parallel

lope
[degrees]

aximum Power Point Tracker Parameters

fficiency
)5

C/AC Converter Parameters

fficiency
)5
rid Operating Voltage
) [Volts]

29

3.3 Summary

Models for EDHW, SDHW and PV systems are developed in this chapter. DHW system models must be simulated at timesteps below the critical timestep. An average water draw is used in the DHW systems so that one simulation can represent the average of a large number of simulations. The demand of an EDHW system is the amount of heat input required to raise the water supply to the set point temperature. The demand of the

SDHW system is the amount of auxiliary heat input required to heat the solar preheated water to the set point temperature plus the pumping power required move the water through the collector. The PV system is controlled to generate electricity at the maximum power point. The electricity generated is supplied to the grid at the grid operating voltage. The models output hourly demands for the electric and solar DHW systems and the hourly grid-connected generation of a PV system.

CHAPTER 4

Marginal Plant Prediction Model

The marginal plant at each hour of the year must be identified to correctly assess the energy and emission savings to a utility. The value of energy saved by a demand-side efficiency measure is based on the operating cost of the marginal plant. Similarly, the avoided emissions are related to the emission characteristics of the marginal plant. A model is developed to identify the marginal plant. The model is based on adding adjusted plant capacities to the generation mix on a least cost basis to meet the load. Plant specific data used in the example calculations are taken from *Advance Plan 7, Technical Support Document D24: Power Supply* (Public Service Commission of Wisconsin, 1994).

4.1 Capacity Adjustments

Utility electric generating plants face forced and scheduled outages during their operation. In order to predict the marginal plant, a methodology is set up to adjust the capacity to account for these outages. The year is broken down into two general seasons, a peak season and a maintenance season. For example, the maintenance seasons may be defined as the spring and fall months when the load is relatively low. The peak seasons then are the winter and summer months when utilities tend to find relatively higher demands. During the peak season, the capacity is adjusted to account for forced outages only. In the maintenance season, the plant capacity is adjusted to account for forced and scheduled outages.

4.1.1 Forced Outage Adjusted Capacity

Electric generating plants may face full forced outages in which case the entire capacity of the plant is lost, or partial forced outages where only a fraction of the capacity is lost. The forced outage adjusted capacity considers both types of outages. Because the exact time of a forced outage cannot be predicted, the forced outage adjusted capacity is calculated statistically based on historical frequency of occurrence. The full forced outage and up to four levels of partial forced outage are accounted for in the forced outage adjusted capacity.

To adjust the nameplate capacity for forced outages, a forced outage adjustment factor is first calculated (FOA factor). The FOA factor is calculated with forced outage and capacity information. The FOA factor is defined in equation 4.1.1.1.

$$\text{FOA factor} = 1 - \text{fullout} - \bullet_{i=1}^{4} \frac{\text{partout}_i * \text{partcap}_i}{\text{Capacity}} \qquad (4.1.1.1)$$

In this equation, fullout and partout are historical fractions of time in which a generating unit experiences full and partial outages respectively. The variable partcap is the remaining capacity that is available for service in the case of a partial outage. It is not the amount of capacity that is lost during the partial outage. The FOA factor is used with the nameplate capacity of the plant to calculate the forced outage adjusted capacity (FOA capacity) as defined in equation 4.1.1.2.

$$\text{FOA capacity} = \text{FOA factor} * \text{Capacity} \qquad (4.1.1.2)$$

The FOA capacity is an effective capacity used to find the marginal plant during

times when the plant is assumed to be operating in the peak season. Table 4.1.1-1 summarizes the FOA capacity and the information required to calculate it for a given mix of generating plants. The data are representative of Wisconsin Electric Power Company in Milwaukee, WI. The FOA capacity is used for further calculation when adjusting the capacity for scheduled outages.

4.1.2 Forced and Scheduled Outage Adjusted Capacity

In addition to adjusting plant capacity for forced outages, capacity also needs to be adjusted for scheduled outages. At times a utility knows exactly when it will take a plant off line. If this is the case, the scheduled outage information can be entered to make the forced and scheduled outage capacity (FSOA capacity) zero. However, there are times when a utility may know only a given time frame in which a plant will be off line. If this is the case, the FSOA capacity has a value and the effective plant capacity is a fraction of its nameplate capacity. This type of adjustment particularly makes sense when looking at a region of utilities in which case it is hard to identify when neighboring utilities will take their plants off line.

Table 4.1.1-1: WEPCO Forced Outage Adjusted Capacity Information

Generating Plant and Unit	Nameplate Capacity [MW]	Full OutageRate [%]	Partial Outage Rate [%]	Partial Capacity [MW]	FOA Capacity [MW]
Point Beach 2	497	1.9	0	0	487.6
Point Beach 1	497	1.9	0	0	487.6
Oak Creek 8	305	1	1.6	85	300.6
Oak Creek 7	280	1	1.6	85	275.8
Oak Creek 6	260	2	3	82	252.3
Oak Creek 5	258	2	2.9	82	250.5
Port Washington 4	80	4	1.5	29	76.4
Port Washington 3	82	4	1.4	29	78.3
Port Washington 2	80	4	1.3	29	76.4
Port Washington 1	80	4	1.3	29	76.4
Valley 4	70	2.5	4	34	66.9
Valley 3	70	1	15	14	67.2
Valley 2	62	2.5	3.9	30	59.3
Valley 1	64	1	13	7	62.5
Pleasant Prairie 2	580	1	1.3	220	571.3
Pleasant Prairie 1	580	1	1.3	220	571.3
Presque Isle 9	84	1	3	14	82.7
Presque Isle 8	83	1	3	14	81.8
Presque Isle 7	81	1	3.2	13	79.8
Presque Isle 6	85	1	2.2	20	83.7
Presque Isle 5	84	1	2.2	19	82.7
Presque Isle 4	57	1	2.4	12	56.1
Presque Isle 3	58	1	2.4	12	57.1
Presque Isle 2	37	0	0	0	37.0
Presque Isle 1	25	0	0	0	25.0
Edgewater 5	97	2	5	38	93.2
Concord 4	83	1	0	0	82.2
Concord 3	83	1	0	0	82.2
Concord 2	83	1	0	0	82.2
Concord 1	83	1	0	0	82.2
Germantown 4	53	1	0	0	52.5
Germantown 3	53	1	0	0	52.5
Germantown 2	53	1	0	0	52.5
Germantown 1	53	1	0	0	52.5
Oak Creek 9	20	1	0	0	19.8
Point Beach 5	20	1	0	0	19.8
Port Washington 6	18	1	0	0	17.8
	5138				5035.5

To adjust the capacity to account for scheduled outages, scheduled outage information is needed to calculate a scheduled outage adjustment factor (SOA factor). The information required includes the scheduled outage, actual amount of time that a plant is taken off line during the year, and the duration of the maintenance period. Equation 4.1.2.1 defines the SOA factor.

$$\text{SOA factor} = 1 - \frac{\text{scheduled outage}}{\text{outage period}} \qquad (4.1.2.1)$$

The outage period is the range of time that the scheduled outage could occur in. Note that by making the outage period equal to the scheduled outage the SOA factor goes to zero. Thus, if a utility knows exactly when a plant is to be off line it can be reflected with a forced and scheduled outage capacity of zero. Equation 4.1.2.2 shows the calculation of the FSOA capacity.

$$\text{FSOA capacity} = \text{SOA factor} * \text{FOA capacity} \qquad (4.1.2.2)$$

Note that the FSOA capacity is based on the capacity previously adjusted for forced outages. This adjustment is to account for the possibility of a forced outage during the maintenance period. Table 4.1.2-1 summarizes the FSOA capacity and the information required to calculate it for WEPCO. With the seasonal adjusted capacities calculated, the marginal plant can be found.

Table 4.1.2-1: WEPCO Forced and Scheduled Outage Adjusted Capacity Information

Generating Plant and Unit	Scheduled Outage Periods (month/day)		Outage Period [hrs]	Scheduled Outage [wks]	Scheduled Outage [hrs]	FSOA Capacity [MW]
Point Beach 2	3/1 - 5/1	9/20 -11/20	2928	6	1008	319.7
Point Beach 1	3/1 - 5/1	9/20 -11/20	2928	6	1008	319.7
Oak Creek 8	3/1 - 5/1	9/20 -11/20	2928	5	840	214.4
Oak Creek 7	3/1 - 5/1	9/20 -11/20	2928	5	840	196.7
Oak Creek 6	3/1 - 5/1	9/20 -11/20	2928	5	840	179.9
Oak Creek 5	3/1 - 5/1	9/20 -11/20	2928	5	840	178.6
Port Washington 4	3/1 - 5/1	9/20 -11/20	2928	0	0	76.4
Port Washington 3	3/1 - 5/1	9/20 -11/20	2928	0	0	78.3
Port Washington 2	3/1 - 5/1	9/20 -11/20	2928	0	0	76.4
Port Washington 1	3/1 - 5/1	9/20 -11/20	2928	0	0	76.4
Valley 4	3/1 - 5/1	9/20 -11/20	2928	0	0	66.9
Valley 3	3/1 - 5/1	9/20 -11/20	2928	0	0	67.2
Valley 2	3/1 - 5/1	9/20 -11/20	2928	8	1334	32.3
Valley 1	3/1 - 5/1	9/20 -11/20	2928	8	1334	34.0
Pleasant Prairie 2	3/1 - 5/1	9/20 -11/20	2928	6	1008	374.6
Pleasant Prairie 1	3/1 - 5/1	9/20 -11/20	2928	6	1008	374.6
Presque Isle 9	3/1 - 5/1	9/20 -11/20	2928	1	168	78.0
Presque Isle 8	3/1 - 5/1	9/20 -11/20	2928	1	168	77.1
Presque Isle 7	3/1 - 5/1	9/20 -11/20	2928	1	168	75.2
Presque Isle 6	3/1 - 5/1	9/20 -11/20	2928	1	168	78.9
Presque Isle 5	3/1 - 5/1	9/20 -11/20	2928	1	168	78.0
Presque Isle 4	3/1 - 5/1	9/20 -11/20	2928	1	168	52.9
Presque Isle 3	3/1 - 5/1	9/20 -11/20	2928	1	168	53.9
Presque Isle 2	3/1 - 5/1	9/20 -11/20	2928	0	0	37.0
Presque Isle 1	3/1 - 5/1	9/20 -11/20	2928	0	0	25.0
Edgewater 5	3/1 - 5/1	9/20 -11/20	2928	4	672	71.8
Concord 4	3/1 - 5/1	9/20 -11/20	2928	0	0	82.2
Concord 3	3/1 - 5/1	9/20 -11/20	2928	0	0	82.2
Concord 2	3/1 - 5/1	9/20 -11/20	2928	0	0	82.2
Concord 1	3/1 - 5/1	9/20 -11/20	2928	0	0	82.2
Germantown 4	3/1 - 5/1	9/20 -11/20	2928	0	0	52.5
Germantown 3	3/1 - 5/1	9/20 -11/20	2928	0	0	52.5
Germantown 2	3/1 - 5/1	9/20 -11/20	2928	0	0	52.5
Germantown 1	3/1 - 5/1	9/20 -11/20	2928	0	0	52.5
Oak Creek 9	3/1 - 5/1	9/20 -11/20	2928	0	0	19.8
Point Beach 5	3/1 - 5/1	9/20 -11/20	2928	0	0	19.8
Port Washington 6	3/1 - 5/1	9/20 -11/20	2928	0	0	17.8
						3889.9

4.2 Least Cost Model

The marginal plant is found on the premise that the plants are added to the generating mix on a least cost basis. Utilities may have reason to employ plants on an ulterior basis. For example, a plant that has poor emission characteristics may be kept

off-line in favor of a more expensive but cleaner plant. However, it is economically beneficial for a utility to add plants to the mix on a least cost basis as operating costs are minimized and higher profit margins are achieved. Although utilities may not consistently add plants to the generating mix on a least cost basis, it is a generality and a reasonable assumption.

Given the load at each hour of the year, the adjusted capacity of each plant is added to the mix on a least cost basis until the load is met. If the hour of the year is within the maintenance season for a given plant, the FSOA capacity is used as its effective capacity to meet the load with. Otherwise, it is in the peak season and the FOA capacity is used as the effective plant capacity for the hour. Table 4.2-1 summarizes the least cost ordering of the plant mix along with the nameplate, FOA and FSOA capacities for WEPCO. This is the order in which the plants are dispatched to meet the load.

Table 4.2-1: WEPCO Least Cost Plant Order and Adjusted Capacities

Generating Plant and Unit	Operating Cost [$/kWh]	Nameplate Cap [MW]	FOA Capacity [MW]	FSOA Capacity [MW]
1 Point Beach 2	0.0048	497	487.6	319.7
2 Point Beach 1	0.0048	497	487.6	319.7
3 Pleasant Prairie 2	0.0090	580	571.3	374.6
4 Pleasant Prairie 1	0.0090	580	571.3	374.6
5 Edgewater 5	0.0136	97	93.2	71.8
6 Oak Creek 8	0.0143	305	300.6	214.4
7 Oak Creek 7	0.0143	280	275.8	196.7
8 Oak Creek 5	0.0148	258	250.5	178.6
9 Oak Creek 6	0.0149	260	252.3	179.9
10 Presque Isle 4	0.0162	57	56.1	52.9
11 Presque Isle 6	0.0163	85	83.7	78.9
12 Presque Isle 5	0.0163	84	82.7	78
13 Presque Isle 1	0.0165	25	25.0	25
14 Presque Isle 2	0.0167	37	37.0	37
15 Presque Isle 3	0.0170	58	57.1	53.9
16 Port Washington 2	0.0199	80	76.4	76.4
17 Port Washington 1	0.0203	80	76.4	76.4
18 Valley 2	0.0214	62	59.3	32.3
19 Valley 4	0.0216	70	66.9	66.9
20 Valley 1	0.0224	64	62.5	34
21 Presque Isle 9	0.0227	84	82.7	78
22 Presque Isle 8	0.0227	83	81.8	77.1
23 Presque Isle 7	0.0227	81	79.8	75.2
24 Valley 3	0.0230	70	67.2	67.2
25 Port Washington 3	0.0237	82	78.3	78.3
26 Port Washington 4	0.0267	80	76.4	76.4
27 Concord 4	0.0470	83	82.2	82.2
28 Concord 3	0.0470	83	82.2	82.2
29 Concord 2	0.0470	83	82.2	82.2
30 Concord 1	0.0470	83	82.2	82.2
31 Oak Creek 9	0.0557	20	19.8	19.8
32 Germantown 4	0.0600	53	52.5	52.5
33 Germantown 3	0.0600	53	52.5	52.5
34 Germantown 2	0.0600	53	52.5	52.5
35 Germantown 1	0.0600	53	52.5	52.5
36 Point Beach 5	0.0637	20	19.8	19.8
37 Port Washington 6	0.0651	18	17.8	17.8
		5138	5035.5	3889.9

4.3 Analysis of Results

The marginal plant is found by adding the appropriate adjusted capacities of the plants to the generation mix in the order described in table 4.2-1 until the load is met. Figure 4.3-1 shows the load and adjusted capacities for the peak and maintenance periods for WEPCO. The maintenance periods are defined as March 1 through May 1 for spring

and September 20 through November 20 for fall. During these times the effective capacity is lower since plants are taken off line for cleaning and repair.

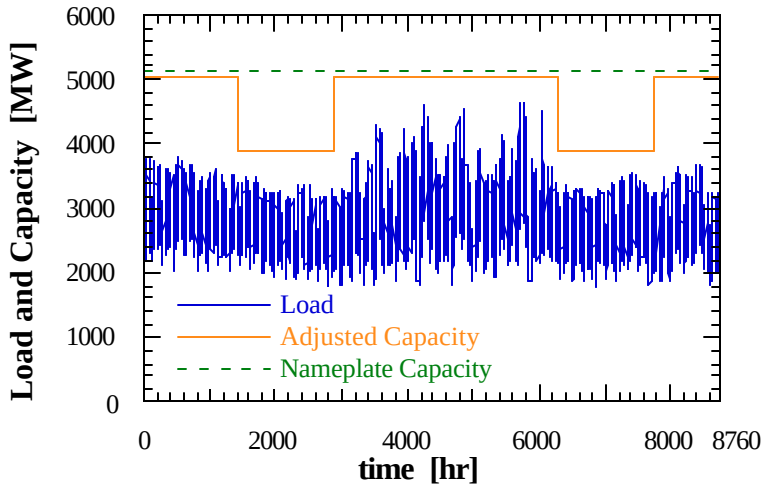

Figure 4.3-1: WEPCO 1991 Load and Adjusted Capacities

Figure 4.3-2 shows the predicted marginal plants for WEPCO using the 1991 load data. The marginal plant number corresponds to the least cost plant order given in table 4.2-1. Taking lower ordered plants off line for maintenance results in relatively higher ordered marginal plants.

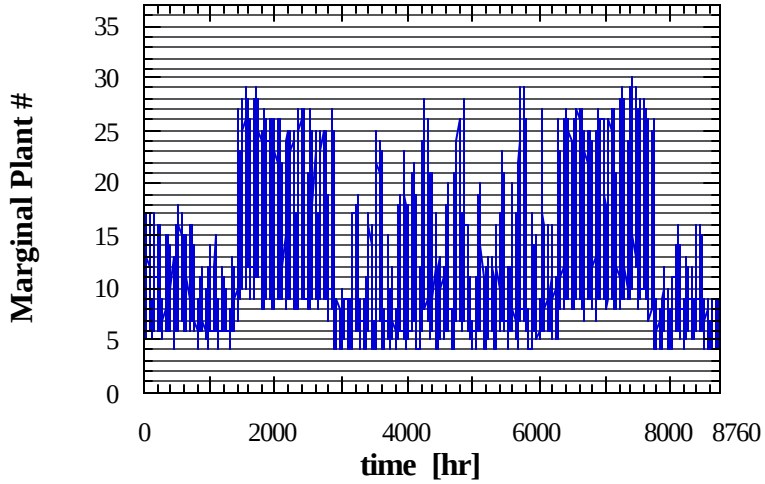

Figure 4.3-2: Predicted Marginal Plant for WEPCO, 1991

Marginal costs can be higher in the maintenance season than in the peak operating season. Referring to figure 4.3-1. it can be seen that at times the available reserve margin is less in the maintenance season than in the peak operating season. The result is that higher marginal operating costs are predicted by the marginal plant prediction model. This is a reality in utility planning as the higher cost plants must meet the load when less expensive plants are down for maintenance. Figure 4.3-3 shows the marginal operating costs predicted with the marginal plant model.

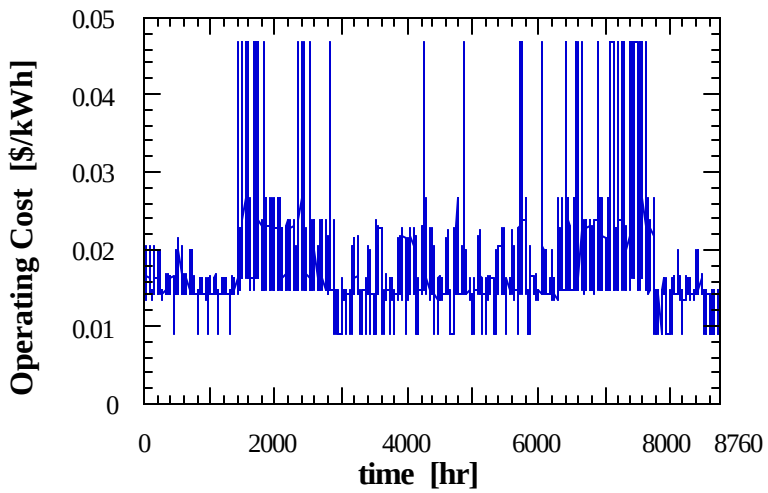

Figure 4.3-3: WEPCO Marginal Operating Costs

At times a utility may not have enough capacity to meet the load. When faced with such a situation a utility must buy the required capacity from a neighboring utility. In this analysis, the utility's highest ordered plant is assumed to be on the margin. It is the operating cost of this plant that is used as the marginal operating cost. This effectively assumes that the utility can buy the required capacity at this cost. This may not be entirely a reality as the supplying utility will sell the capacity with a profit margin.

However, it is a reasonable assumption for this analysis.

The prediction of the marginal plant is not limited to a single utility analysis. By gathering like information for a group of neighboring utilities or a utility region, a larger system can be defined. This approach represents a more realistic environment in which utilities buy and sell energy and capacity from one another. The same methodology applies as in the single utility analysis. However, the loads of each utility that make up the system must be combined to give a total system load.

Figure 4.3-4 shows the load and effective capacities for a utility region consisting of Wisconsin Electric Power Company (WEPCO), Wisconsin Public Service Corporation (WPS), Wisconsin Power and Light Company (WPL), Madison Gas and Electric (MG&E), Northern States Power Company (NSP) and Dairyland Power Cooperative (DPC). The maintenance periods are defined as March 1 through May 1 for spring and September 20 through November 20 for fall. Defining a utility region accounts for sales between utilities. Sales and purchases outside the defined region are not accounted for. To credit purchases from a utility outside the defined region, the purchase may be added to the plant data as an effective generating unit.

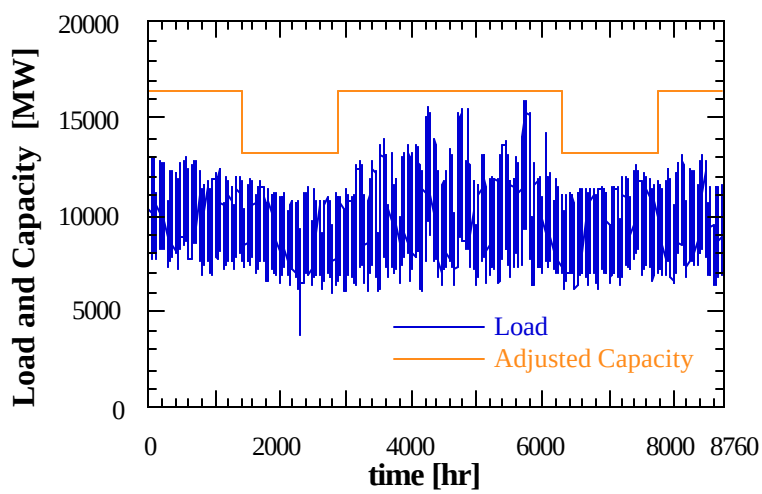

Figure 4.3-4: Regional 1991 Load and Adjusted Capacities

Figure 4.3-5 shows the marginal operating costs for the defined region. The marginal operating costs are generally lower when considering an interconnected system rather than an isolated system. The operating costs are not as extreme in the maintenance periods compared to those seen in the isolated system. The marginal operating costs predicted in the maintenance period for the isolated system are artificially high since there is no account for purchases from neighboring utilities. The trend of experiencing higher operating costs at times in the maintenance periods than at times in the peak season is apparent as in the case of the isolated utility. The regional analysis gives a more realistic representation of the marginal operating costs seen by a utility than the isolated system analysis.

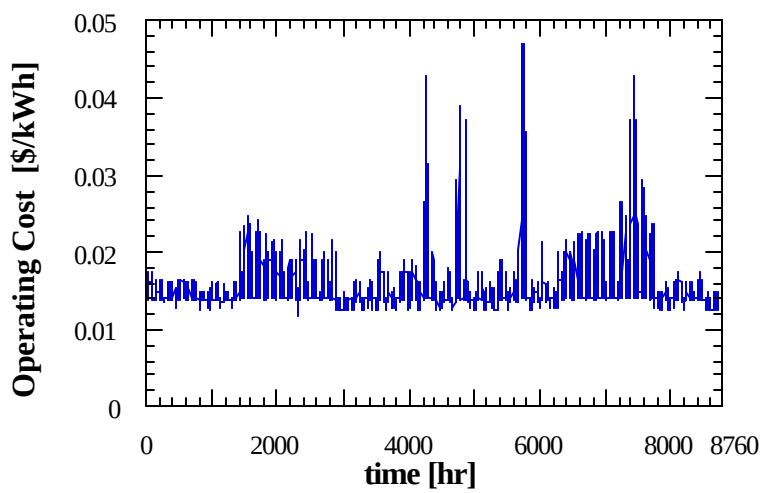

Figure 4.3-5: Regional Marginal Operating Costs

4.4 Summary

A model for determining the marginal plant is developed in this chapter. The

model is based on the premise that generating plants are added to generation mix on a least cost of operation basis. The nameplate capacity of each plant is modified to account for forced outages in the peak load seasons and forced and scheduled outages in maintenance periods. Generating units are added to the mix until the total effective capacity meets the load at a given hour. This analysis can, and should, be extended to encompass a larger system than a single utility. By including the generating capacity and loads of neighboring utilities in the analysis, a more realistic environment in which utilities buy and sell energy and capacity from one another is analyzed.

CHAPTER 5

Quantifying Utility Costs and Benefits

Equations to assess the costs and benefits of an ensemble of solar energy systems are developed. Some benefits require knowledge of solar system performance and the marginal plant. Solar system performance is evaluated to find the hourly demand displacement of the option at the consumer level. Identifying the marginal plant allows for assessing the economic and environmental impact at the generation level through plant characteristics of the last plant to be added to the generation mix. Using these two pieces of information together allows for quantifying energy, emission and demand reductions and their economic benefit to a utility.

5.1 Assessing the Costs of a Solar DSM Implementation

The costs of a solar DSM program include the first cost of purchasing the system and any operation and maintenance costs required by the systems. These costs are primarily a function of the number of systems to be installed in the solar DSM program. Defining the number of systems that are installed in the DSM program requires an estimation of the percentage of residential customers that will accept the solar program. The number of solar systems used in the analysis is given in equation 5.1.1.

$$N_{systems} = N_{customers} * \frac{\%\ accept}{100} \qquad (5.1.1)$$

where

$N_{customers}$ = the number of residential customers supplied by the utility

% accept = the percentage of residential customers that will accept the program

The total cost of the systems is given in equation 5.1.2. The cost used in determining the investment is the installed cost of a single system. The total operation, maintenance and administration costs are given in equation 5.1.3. An estimation of the yearly operation and maintenance costs is required. Generally, there is no cost to the utility associated with solar system operation since the homeowner pays for the energy required to operate the solar systems. Other costs that may be considered in the OM&A term include administrative costs and overhead associated with the program. The operation, maintenance and administration cost is given on a yearly basis per system ($/system-yr).

$$\text{Investment} = N_{systems} * Cost_{system} \tag{5.1.2}$$

$$\text{OM\&A} = N_{systems} * Cost_{OM\&A} \tag{5.1.3}$$

5.2 Assessing Energy Reduction and Its Value

Assessing the value of energy reduction requires knowledge of the total amount of energy reduction at the generation level. The total energy reduction at the generation level is found with the average system performance information, the number of installed systems in the solar DSM program and the transmission and distribution losses. The system performance is found at the consumer level and passed back through the distribution and transmission systems to the generation level.

Electricity generated by a power plant is passed through transmission and distribution systems before it reaches the consumer. The transmission system supplies a

group of distribution systems which in turn supply the customer. Figure 5.2-1 depicts a simple representation of the system as a whole. Power losses are experienced as the electricity makes its way through these systems to the consumer. These power losses are typically given as percentages of the total power coming into the system. For example, the power loss in transmission might be 3% of the power supplied by the generation units. Generation units must supply a greater amount of power than is demanded at the consumer level to overcome these losses. Demand met with solar systems at the consumer level therefore has a greater impact at the generation level in terms of avoided supply since these losses do not have to be met.

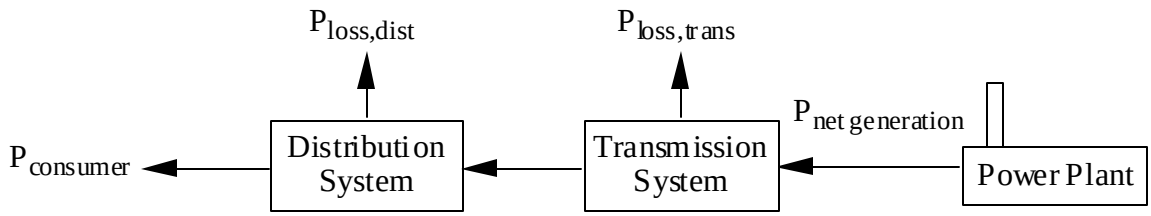

Figure 5.2-1: Electric System Representation

Solar energy systems supply energy at the consumer level. SDHW systems supply energy in the form of hot water whereas PV systems supply energy in the form of electricity. The models developed in Chapter 3 are used to assess system performance. SDHW system performance is defined as the demand of a conventional EDHW system minus the demand of the SDHW system. PV system performance is assessed by the grid-connected electricity generation. In both cases the result is a reduction in demand that is required to be supplied by the generating plants to the consumer.

To assess the reduction in electricity that needs to be generated by the power plants, the hourly system performance, as previously defined, is scaled by the number of installed solar systems and passed back through the distribution and transmission system.

Equation 5.2.1 defines the reduction in power generation requirements. By summing the hourly reduction values over the year, the energy reduction is obtained (equation 5.2.2).

$$P_{reduction,\ generation} = \frac{N_{systems} * P_{system}}{(1\text{-}Loss_{distribution}) * (1\text{-}Loss_{transmission})} \quad (5.2.1)$$

where:

$$P_{system} = \begin{cases} P_{EDHW} - P_{SDHW} & \text{for an SDHW system} \\ P_{PV} & \text{for a PV system} \end{cases}$$

$Loss_{distribution}$ = the fraction of power lost in the distribution system

$Loss_{transmission}$ = the fraction of power lost in the distribution system

$$E_{reduction,\ generation} = \sum_{i=1}^{8760} P_{reduction,\ generation_i} \Delta t \quad (5.2.2)$$

where:

Δt = 1 hour

With methodologies to obtain the amount of avoided power production at the generation level and the marginal plant at each hour of the year, the total savings at the generation level can be assessed in terms of dollars. A TRNSYS file reads in the system demands generated with the solar energy and conventional system models and calculates the impact of system performance at the generation level, as discussed, on an hourly basis. The operating cost of the marginal plant is used to assess the savings in terms of dollars. Equation 5.2.3 calculates the hourly dollar savings. These savings are then summed over the year to give the annual energy savings (equation 5.2.4).

$$\text{Energy Savings}_{\text{generation, hour}} = P_{\text{reduction, generation}} * \text{Operating Cost}_{\text{margin}} \quad (5.2.3)$$

$$\text{Energy Savings}_{\text{generation}} = \sum_{\text{hour}=1}^{8760} \text{Energy Savings}_{\text{generation, hour}} \Delta t \quad (5.2.4)$$

where:

$\Delta t = 1$ hour

5.3 Assessing Emission Reduction and Its Value

In order to quantify avoided emissions, emission characteristics of each plant in the mix are required. Emissions for which data are available include CO_2, SO_2, NO_X, N_2O, total suspended particulates and CH_4. Other emissions that may be considered are mercury (heavy metals) and nuclear wastes. Table 5.3-1 lists the emission rates for WEPCO generating plants. The data for CO_2, SO_2, NO_X, N_2O, total suspended particulates and CH_4 are given in terms of lbm/MWh and are taken from *Impact on a Utility of an Ensemble of Solar Domestic Hot Water Systems* (Cragan, 1994). These values can be derived from emission and heat rate information available in *Advance Plan 7, Technical Support Document D24: Power Supply* (Public Service Commission of Wisconsin, 1994).

Table 5.3-1: WEPCO Emission Rate Data

Generating Plant and Unit	CO_2 [lbm/MWh]	SO_2 [lbm/MWh]	NO_X [lbm/MWh]	N_2O [lbm/MWh]	Parts [lbm/MWh]	CH_4 [lbm/MWh]	Mercury [lbm/MWh]	Nuclear Waste [lbm/MWh]
Point Beach 2	0	0.00	0.00	0.0000	0.000	0.000	NA	NA
Point Beach 1	0	0.00	0.00	0.0000	0.000	0.000	NA	NA
Oak Creek 8	1868	7.60	2.56	0.0165	0.183	0.010	NA	NA
Oak Creek 7	1868	7.60	2.56	0.0165	0.183	0.010	NA	NA
Oak Creek 6	1907	7.76	2.62	0.0168	0.187	0.010	NA	NA
Oak Creek 5	1904	7.75	2.61	0.0168	0.187	0.010	NA	NA
Port Washington 4	2492	26.84	4.31	0.0180	0.479	0.191	NA	NA
Port Washington 3	2155	32.20	3.73	0.0155	0.414	0.165	NA	NA
Port Washington 2	2167	23.34	3.75	0.0156	0.417	0.166	NA	NA
Port Washington 1	2237	24.09	3.87	0.0161	0.430	0.171	NA	NA
Valley 4	2436	26.58	5.86	0.0222	0.586	0.013	NA	NA
Valley 3	2436	26.58	5.86	0.0222	0.586	0.013	NA	NA
Valley 2	2436	26.58	5.86	0.0222	0.586	0.013	NA	NA
Valley 1	2557	27.91	6.15	0.0234	0.615	0.014	NA	NA
Pleasant Prairie 2	2313	8.11	4.32	0.0184	0.108	0.014	NA	NA
Pleasant Prairie 1	2313	8.11	4.32	0.0184	0.108	0.014	NA	NA
Presque Isle 9	2392	12.54	8.05	0.0173	0.230	0.014	NA	NA
Presque Isle 8	2392	12.53	8.05	0.0172	0.230	0.014	NA	NA
Presque Isle 7	2392	12.53	8.05	0.0172	0.230	0.014	NA	NA
Presque Isle 6	2237	16.54	8.90	0.0159	0.424	0.012	NA	NA
Presque Isle 5	2238	16.55	8.91	0.0159	0.318	0.012	NA	NA
Presque Isle 4	2250	16.63	6.50	0.0160	0.426	0.012	NA	NA
Presque Isle 3	2250	16.63	6.50	0.0160	0.320	0.012	NA	NA
Presque Isle 2	3028	22.39	12.05	0.0215	1.292	0.016	NA	NA
Presque Isle 1	3381	19.23	13.46	0.0240	0.321	0.018	NA	NA
Edgewater 5	0	0.00	0.00	0.0000	0.000	0.000	NA	NA
Concord 4	1609	0.00	1.16	0.1803	0.000	0.004	NA	NA
Concord 3	1609	0.00	1.16	0.1803	0.000	0.004	NA	NA
Concord 2	1609	0.00	1.16	0.1803	0.000	0.004	NA	NA
Concord 1	1609	0.00	1.16	0.1803	0.000	0.004	NA	NA
Germantown 4	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Germantown 3	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Germantown 2	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Germantown 1	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Oak Creek 9	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Point Beach 5	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA
Port Washington 6	3296	41.60	13.60	0.1600	0.800	0.000	NA	NA

Total avoided emissions are directly related to the energy reduction at the generation level and the marginal plant. To quantify emission reductions, the hourly energy reduction is calculated as discussed in section 5.3. The hourly energy reduction is essentially the same as the hourly demand reduction since the calculations are performed on an hourly basis ($P_{reduction,generation}$ [MW] * 1 [hr] = $E_{reduction,hour,generation}$ [MWh]). The term $P_{reduction,\ generation}$ will be used to refer to hourly energy reduction in this section. The hourly energy reduction is multiplied by the marginal emission rate of a

given emission to give the hourly emission reduction (in lbm). The marginal emission rate is found by predicting the marginal plant at the hour as discussed in section 4.3. Equation 5.3.1 shows the calculation for the hourly reduction of a given emission. In this equation the term Emission is used generically to represent the calculation for any given emission (CO_2, SO_2, etc.). The annual emission reduction is found by summing the hourly emission reduction over the year as shown in equation 5.3.2.

$$\text{Emission Reduction}_{\text{hour}} = P_{\text{reduction, generation}} * \frac{\text{Emission Rate}_{\text{margin}}}{1000} \quad (5.3.1)$$

$$\text{Emission Reduction}_{\text{year}} = \sum_{\text{hour}=1}^{8760} \text{Emission Reduction}_{\text{hour}} \Delta t \quad (5.3.2)$$

where:

$\Delta t = 1$ hour

The value of reducing an emission will vary among utilities. In some areas utilities must buy credits to emit a certain pollutant. This purchase is a real cost to a utility and thus, reducing emissions has value. Other value that may be placed on avoided emissions might include the cost of equipment that would be needed to handle the emission such as scrubbers or baghouses. In any case the value of reducing the emission must be given in terms of current $/lbm, not in terms of present worth or levelized dollars. Equation 5.3.3 shows the calculation for assessing the savings associated with reducing emissions. The total yearly savings to the utility due to emission reduction is the sum of all of the individual yearly emission savings (equation 5.3.4).

$$\text{Emission Savings} = \text{Emission Reduction}_{\text{year}} * \text{Emission Cost} \quad (5.3.3)$$

where

Emission Cost = Value to the utility of reducing the emission [$/lbm]

$$\text{Total Emission Savings} = \sum_{i=1}^{\#\text{ emissions}} \text{Emission Savings}_i \qquad (5.3.4)$$

5.4 Assessing Demand Reduction and Its Value

The value of reducing demand is identified in three areas. Demand reduction has value at the generation level as it reduces capacity and reserve requirements. Demand reduction is also beneficial to the transmission and distribution systems since it lessens their capacity requirements. The avoided costs of meeting the capacity needs has value to generation, transmission and distribution systems.

Demand reduction can be assessed using a peak load hour method or the capacity contribution index (CCI) method. The former method assesses demand reduction as the avoided generation at a single peak load hour or as the average demand reduction for a specified number of hours with highest loads. The CCI method assesses demand contributions over the entire year, weighted by the marginal expected unserved energy (EUE). The methodologies for assessing demand reduction and its value to a utility of both approaches are developed in the following sections.

5.4.1 Peak Load Hour Method

The peak load hour method assesses the average demand reduction at a specified number of peak load hours. The first step in this approach is to identify the peak loads and the hours at which they occur. Figure 5.4.1-1 shows the twenty highest loads experienced by WEPCO in 1991 and the hours at which they occur. The solar energy system demand reductions at these hours are then identified to assess demand

contributions to the generation, transmission and distribution systems.

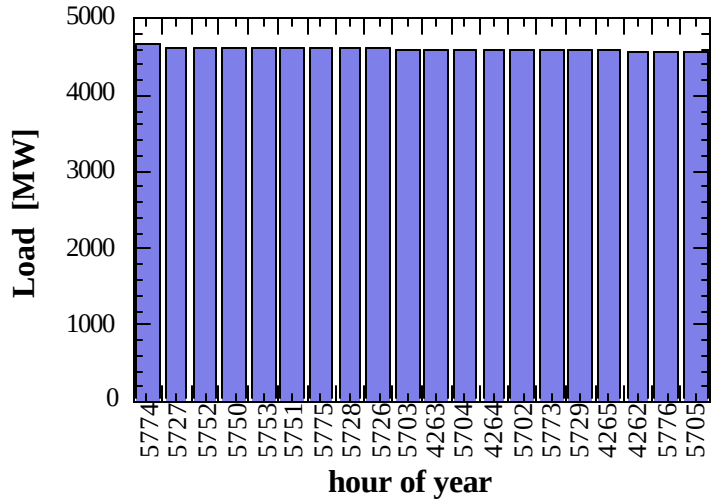

Figure 5.4.1-1: Peak Loads and Time of Occurrence. WEPCO, 1991

To quantify the reduction in capacity requirements, the solar energy system performance, as defined in section 5.2, is used. Generation utilities must have enough capacity to meet the load, overcome transmission and distribution losses and maintain a certain reserve margin to provide a desired level of reliability. Equation 5.4.1.1 gives the average reduction in capacity requirements for an electric generation utility due to an ensemble of solar systems.

$$\text{Capacity}_{\text{reduction, generation}} = \frac{\dfrac{N_{\text{systems}}}{n_{\text{peak hours}}} * \bullet_{i=1}^{n_{\text{peak hours}}} P_{\text{system, peak hour}_i}}{(1\text{-Loss}_{\text{distribuiton}}) * (1\text{-Loss}_{\text{transmission}})} * (1 + \text{reserve margin})$$

(5.4.1.1)

where:

$n_{\text{peak hours}}$ = the number of peak load hours investigated

$P_{\text{system, peak hour}_i}$ = the solar system performance at the peak load hour

reserve margin = the fractional reserve margin of the generation utility

Capacity requirement reductions for the transmission and distribution systems are found in a similar manner. The transmission system must have enough capacity to supply the load and overcome transmission and distribution losses. However, in typical cost analysis of transmission systems, costs are given in terms of the demand that must be supplied to the distribution systems. Thus, only the distribution losses impact the capacity reduction calculation. Equation 5.4.1.2 gives the average capacity reduction requirement for the transmission system due to an ensemble of solar systems. The distribution system needs sufficient capacity to supply the load and overcome the distribution losses. Similar to the transmission system though, a distribution system cost analysis is defined in terms of demand that must be supplied to the consumer. The capacity reduction is thus given in terms of demand reduction at the consumer level. Equation 5.4.1.3 gives the average capacity reduction requirement for a distribution system.

$$\text{Capacity}_{\text{reduction, transmission}} = \frac{\frac{N_{\text{systems}}}{n_{\text{peak hours}}} * \sum_{i=1}^{n_{\text{peak hours}}} P_{\text{system, peak hour}_i}}{(1-\text{Loss}_{\text{distribuiton}})}$$

(5.4.1.2)

$$\text{Capacity}_{\text{reduction, distribution}} = \frac{N_{\text{systems}}}{n_{\text{peak hours}}} * \sum_{i=1}^{n_{\text{peak hours}}} P_{\text{system, peak hour}_i}$$

(5.4.1.3)

With the reduction in capacity requirements found for the generation, transmission and distribution systems, a value can be placed on the reductions. The value of reducing capacity requirements at the generation level is based relative to the cost per kW of meeting the capacity needs with a conventional option. A combustion turbine is commonly used to supply peak loads due to its low initial cost relative to a coal or

nuclear power plant. Equation 5.4.1.4 gives the value of reducing capacity requirements to a generation utility.

$$\text{Demand Savings}_{\text{generation}} = \text{Capacity}_{\text{reduction, generation}} * \text{Cost}_{\text{conventional option}} \qquad (5.4.1.4)$$

where:

$\text{Cost}_{\text{conventional option}}$ = the present worth cost of a conventional option [$/kW]

The value to transmission and distribution systems due to demand reductions are found in a similar manner. The cost used in assessing the value of reducing capacity requirements is the cost per kW of adding sufficient facilities and equipment to supply the demand. In the case of the transmission system, the demand is that which is supplied to the distribution system. In the case of the distribution system, the demand is that which is supplied to the consumer. The cost is given in present worth dollars per kW. Equations 5.4.1.5 and 5.4.1.6 give value of reducing capacity requirements to transmission and distribution systems respectively. Equation 5.4.1.7 gives the value of the total demand savings due to an ensemble of solar energy systems.

$$\text{Demand Savings}_{\text{transmission}} = \text{Capacity}_{\text{reduction, transmission}} * \text{Cost}_{\text{adding capacity}} \qquad (5.4.1.5)$$

$$\text{Demand Savings}_{\text{distribution}} = \text{Capacity}_{\text{reduction, distribution}} * \text{Cost}_{\text{adding capacity}} \qquad (5.4.1.6)$$

$$\text{Demand Value} = \text{Demand Savings}_{\text{generation}} + \text{Demand Savings}_{\text{transmission}} + \text{Demand Savings}_{\text{distribution}} \qquad (5.4.1.7)$$

A capacity reduction ratio (CRR) is defined as the ratio of system performance to optimal performance. The optimal performance is defined as the maximum possible system performance. For an SDHW system, the optimal system performance is the maximum average EDHW system demand. For a PV system, the optimal performance is

defined as the maximum generation provided by the system. This ratio is calculated at the peak load hours and averaged. The CRR Equation 5.4.1.8 gives the CRR for a solar resource. The CRR attempts to estimate the capacity contribution index of the solar option, as discussed in the following section.

$$CRR = \frac{1}{n_{peak\ hours}} \bullet_{i=1}^{n_{peak\ hours}} \frac{P_{system,\ peak\ hour_i}}{P_{optimal}} \qquad (5.4.1.8)$$

5.4.2 Capacity Contribution Index Method

The Capacity Contribution Index (CCI) method of assessing the value of demand reduction compares the contribution to system reliability of a supply-side or demand-side resource to that of a conventional resource (Harsevoort and Arny, 1994). Capacity contributions normalized to the maximum possible (optimal) capacity of the resource are weighted by the marginal expected unserved energy (EUE) on an hourly basis. The marginal EUE is a measure of system stress at each hour. The marginal EUE considers full and partial forced outages of the generation units. Hours with higher marginal EUE values indicate times of greater stress compared to hours with lower marginal EUE values. Capacity contributions at hours with higher EUE values have greater significance to improving system reliability than capacity contributions at hours with lower marginal EUE values. The marginal EUE values are calculated on a regional basis. The sum of the hourly marginal EUE values is equal to unity (Harsevoort and Arny, 1994).

Figure 5.4.2-1 shows the marginal EUE values for the utility region containing WEPCO. The region is made up of interconnected generating facilities in Wisconsin, Illinois, Iowa, Minnesota, Nebraska, North Dakota, South Dakota and Manitoba

(Harsevoort and Arny, 1994). Hours not shown in the figure have marginal EUE values of zero. Marginal EUE values of zero indicate times of excess capacity.

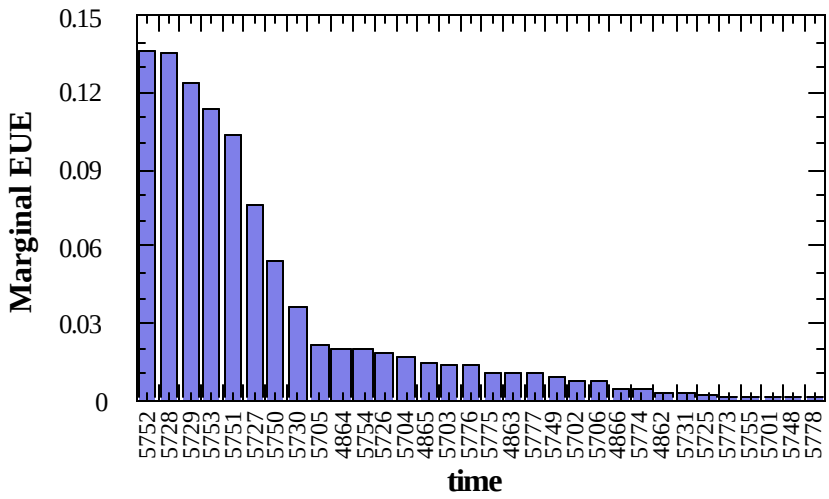

Figure 5.4.2-1: Regional Marginal EUE Values

The first step in assessing the CCI of a solar energy resource is to define an optimal system performance to normalize the hourly system performance. For an analysis of an ensemble of SDHW systems, the optimal system performance is defined as the maximum average demand of an ensemble of EDHW system. For an analysis of an ensemble of PV systems, the optimal system performance is defined as the maximum average generation of the PV ensemble. The optimal system performance is a measure of the maximum possible performance of the system. Normalizing the system performance to a optimal system performance provides a basis for calculating the hourly CCI values for solar options.

The marginal CCI values of the solar energy resource are calculated on an hourly basis. The normalized system performance is weighted by the marginal EUE of the electric generation region. This weighting of system performance credits capacity contributions of the solar energy resource at times of higher system stress than contributions at times of lower system stress. Equation 5.4.2.1 gives the marginal CCI

for a solar resource.

$$CCI_{solar,\ marginal} = \frac{P_{system}}{P_{optimal}} * EUE_{marginal} \qquad (5.4.2.1)$$

The sum of the marginal CCI values over the entire year gives the CCI of the solar resource (equation 5.4.2.2). The CCI of the resource given in equation 5.4.2.2 indicates the contribution to system reliability of the resource. As defined, the CCI will range between 0 and 1. If the resource provides its optimal capacity at each hour, its CCI will be unity since the marginal EUE values add to unity. When the resource provides less than its optimal capacity at times throughout the year, its CCI will be less than 1.

$$CCI_{solar} = \bullet_{i=1}^{8760} CCI_{solar,\ marginal_i} \qquad (5.4.2.2)$$

The CCI of the solar resource is used to compare its contribution to system reliability versus that of a conventional option that would contribute the same amount of optimal capacity. Relative reliability improvements are assessed for generation, transmission and distribution systems. The same considerations are used in calculating the capacity reductions for each system as described in section 5.4.1. Equations 5.4.2.3, 5.4.2.4 and 5.4.2.5 give the capacity reduction requirements for the generation, transmission and distribution systems respectively. The value assessed through these equations is the equivalent kW of a conventional option provided by the solar system. For example if the conventional option used for comparison is a combustion turbine, the equations give the amount of equivalent combustion turbine capacity that is displaced with the solar resource.

$Capacity_{reduction,\ generation} =$

$$\frac{CCI_{solar}}{CCI_{conventional}} * P_{optimal} \cdot N_{systems} * \frac{1 + \text{reserve margin}}{(1\text{-}Loss_{distribution}) * (1\text{-}Loss_{transmission})}$$

(5.4.2.3)

$$Capacity_{reduction,\ transmission} = \frac{CCI_{solar}}{CCI_{conventional}} * \frac{P_{optimal} \cdot N_{systems}}{1\text{-}Loss_{distribution}} \qquad (5.4.2.4)$$

$$Capacity_{reduction,\ distribution} = \frac{CCI_{solar}}{CCI_{conventional}} * P_{optimal} \cdot N_{systems} \qquad (5.4.2.5)$$

The CCI method allows for placing value on demand reduction in terms of the cost of a conventional reference option. The capacity displacements, given in terms of kW, reflect the amount of capacity reduction of an ensemble of solar energy systems. The cost used to quantify the demand savings to the generation utility is the cost of the reference option per kW since the reference option is the resource being displace. The cost is given in terms of present worth $/kW. The cost used to quantify demand savings to the transmission and distribution systems is the marginal cost of supplying a kW. The cost used for placing value on demand reduction to a transmission system is that of adding sufficient facilities to supply an added kW to the distribution system, given in present worth $/kW. The cost used to quantifying demand savings to a distribution system is that of adding the necessary facilities to supply an added kW to the consumer. Equations 5.4.2.6, 5.4.2.7 and 5.4.2.8 give the value of demand reduction to the generation, transmission and distribution systems respectively. Equation 5.4.2.9 gives the value of the total demand savings due to an ensemble of solar energy systems

$$\text{Demand Savings}_{generation} = Capacity_{reduction,\ generation} * Cost_{conventional\ option} \qquad (5.4.2.6)$$

$$\text{Demand Savings}_{transmission} = Capacity_{reduction,\ transmission} * Cost_{adding\ capacity} \qquad (5.4.2.7)$$

$$\text{Demand Savings}_{distribution} = Capacity_{reduction,\ distribution} * Cost_{adding\ capacity} \qquad (5.4.2.8)$$

$$\text{Demand Value} = \text{Demand Savings}_{generation} + \text{Demand Savings}_{transmission} + \text{Demand Savings}_{distribution} \quad (5.4.2.9)$$

5.5 Assessing the Value of Other Benefits

Identifying other benefits of a large scale implementation of solar energy systems is discussed in section 2.2. Other benefits identified are government incentives, customer retention and delayed power plant construction. This section assesses the value of these benefits.

Government incentives are often offered for investment in renewable resources. For example, a tax credit may be given towards the initial investment. Equation 5.5.1 gives the total value of a tax credit towards the investment in solar energy systems. The credit given by the government is on the order of 10 percent of the investment. The government may also offer a subsidy for energy produced by a renewable resource. Equation 5.5.2 gives the total value of the energy subsidy. Typical government subsidies are on the order of 0.01 - 0.02 $/kWh.

$$\text{Tax Credit} = \text{Investment} * \frac{\text{\% government credit}}{100} \quad (5.5.1)$$

$$\text{Subsidy} = E_{reduction,generation} * \text{government subsidy} \quad (5.5.2)$$

A solar DSM program may increase the market of an electric utility through customer retention or capturing new markets. Customer retention is defined as the difference in the number of customers lost to an alternative fuel without the solar program and those which are lost with the program. Equation 5.5.3 can be used to place

value on customer retention if it is believed that there is value in retaining electric customers. The number of customers lost with and without the program is estimated as a percentage of the total residential customers ($Loss_{with\ program}$ and $Loss_{w/o\ program}$). If the solar program brings in new customers the percentage of customers lost with the program is negative. The value of retaining a single customer ($Value_{retention}$) is given in terms of present worth dollars per customer.

$$\text{Retention Value} = N_{customers} * \left(\frac{Loss_{w/o\ program} - Loss_{with\ program}}{100}\right) * Value_{retention} \quad (5.5.3)$$

The value of delaying power plant construction is given in equation 5.5.4. This term may be used to account for value beyond the direct economic savings due to deferred capacity requirements. For simplicity, the demand reduction at the peak load hour is used as an effective capacity reduction. The value of delaying power plant construction ($Value_{delay}$) is given in terms of present worth dollars per peak load kW ($/peak kW).

$$\text{Delay Value} = Capacity_{reduction,\ generation,\ peak\ hour} * Value_{delay} \quad (5.5.4)$$

5.6 Summary

Equations to quantify costs and benefits of a large scale implementation of solar energy systems are developed in this chapter. The value of energy and emission reductions are impacted by the marginal plant. The marginal plant defines the operating costs seen by the utility and the emission characteristics of the last plant added to the generation mix. Demand reduction is assessed with the peak load hour and capacity contribution index methods. The peak load hour method assesses average demand reduction at a specified number of peak load hours. The CCI method assesses demand

reduction in terms of a conventional reference resource. Equations are developed to assess the values of other benefits including government incentives, customer retention and delayed power plant construction.

CHAPTER 6

Economic Analysis

An economic model is developed to evaluate the cost of serving customer electric needs with solar energy systems relative to conventional methods. A method for assessing the value of the costs and benefits of the solar energy system is discussed in chapter 5. The economic model developed calculates the present worth of the life cycle savings (LCS), levelized savings and rate of return (ROR) of a solar energy resource option relative to a conventional resources.

6.1 Present Worth of Life Cycle Savings

The preliminary step in performing an economic analysis of a solar DSM is to define the necessary economic parameters. The required economic parameters to be used in the analysis are the appropriate inflation rate (inf), discount rate (dis) and economic life of the solar energy system (N_{life}). The time and frequency of occurrence of the cash flows associated with the costs and benefits and other economic considerations of the option must be identified to determine the present worth of the life cycle savings of a solar energy resource. Other economic considerations identified are the depreciation of the solar equipment and the downpayments and lease payments made by the customer. Figure 6.1-1 shows graphical representation of the economic model with a time series

representation of the considered cash flows. The terms A, B, C and D represent combined cash flows of the costs and benefits from a solar DSM program.

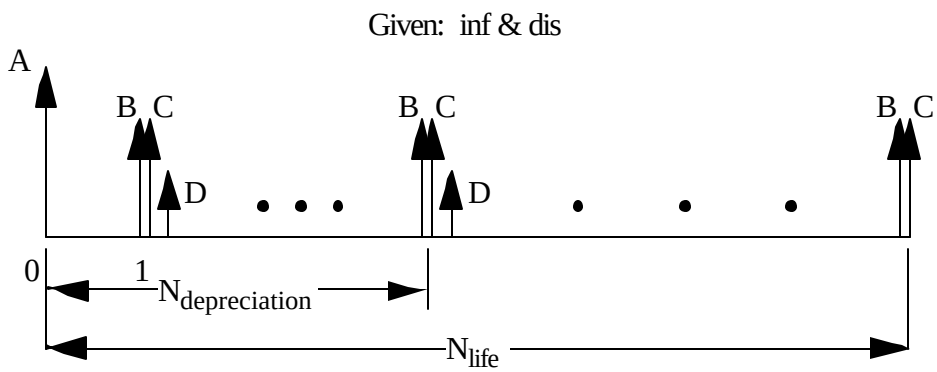

Figure 6.1-1: The Economic Model

The cash flows are categorized by their occurrence and how they are handled in the economic calculation. Equation 6.1.1 gives the present worth of the life cycle savings of a solar energy option relative to a conventional option.

$$LCS_{PW} = A + B*PWF(N_{life},inf,dis) + C*PWF(N_{life},0,dis) + D*PWF(N_{depreciation},0,dis) \quad (6.1.1)$$

where:

A = -Investment + Tax Credit + Demand Value + Delay Value + Retention Value + Downpayments

B = Energy Savings + Total Emission Savings + Subsidy - OM&A

C = Lease Payments (monthly lease payment *12)

D = Depreciation

inf = inflation rate

dis = discount rate

N_{life} = economic life of solar energy system

$N_{depreciation}$ = number of years of equipment depreciation schedule

The parameters that make up the A term in equation 6.1.1 are credited for a time zero. The investment and associated government tax credit and customer downpayments are assumed to occur immediately. The value of demand is given as the cost in present dollars of an option that would supply an equivalent amount of demand that is provided by the solar energy systems. A common example of such an option is a combustion turbine. Similarly, delaying the construction of new facilities is credited for in present worth dollars. This term accounts for any additional value of demand reduction beyond capacity contributions such as the ability to invest money that would be needed to pay for the new facilities. Customer retention is also credited for at time zero in terms of present worth dollars.

The series of benefits that make up the B term in equation 6.1.1 are brought back to present time with the present worth factor (equation 6.1.2) using the parameters N_{life}, inf and dis (Duffie and Beckman, 1991). The present worth factor term is represented in equation 6.1.1 as PWF(N_{life},inf,dis). The terms in this series of benefits are assumed to inflate over the life of the option.

$$PWF(N,i,d) = \frac{1}{(d-i)} * \left[1 - \left(\frac{1+i}{1+d}\right)^N\right] \qquad \text{if } i \neq d$$

$$PWF(N,i,d) = \frac{N}{(i+1)} \qquad \text{if } i = d \qquad (6.1.2)$$

The series of lease payments (term C) are brought back to present value using the present worth factor PWF(N_{life},0,dis). The economic calculation is simplified by assuming that the utility sees an annual lease payment rather than monthly payments. It is assumed that the customer will pay the same monthly payment over the life of the program. That is, the lease payment does not inflate.

The solar energy equipment is depreciable if the utility retains ownership of it. The equipment may be depreciated over a separate life span ($N_{depreciation}$). Straight line depreciation is assumed for model simplicity. As with the lease payments, the depreciation is not inflated. Equation 6.2.3 gives the calculation for the present worth of the solar energy systems.

$$\text{Depreciation}_{PW} = \frac{\text{Investment}}{N_{depreciation}} * \frac{\text{tax bracket}}{100} * PWF(N_{depreciation},0,dis) \tag{6.2.3}$$

where:

tax bracket = the tax bracket of the utility [%]

6.2 Levelized Life Cycle Savings

With the present worth of the life cycle savings calculated, the levelized savings of the option can be found using equation 6.2.1. The levelized savings of an option is the uniform series of payments that the utility would see over the life of the option. In other words, it is the uniform series of income with no inflation that equals the present worth of the life cycle savings.

$$LCS_{Levelized} = \frac{LCS_{PW}}{PWF(N_{life},0,d)} \tag{6.2.1}$$

6.3 Rate of Return of an Option

The rate of return (ROR) is the discount rate that makes the present worth of the life cycle savings equal to zero (equation 6.3.1). Due to the complexity of the PWF equation, it is difficult to explicitly solve equation 6.3.1 for the rate of return. A

numerical method is used to solve the rate of return.

$$0 = A + B*PWF(N_{life},inf,ROR) + C*PWF(N_{life},0,ROR) + D*PWF(N_{depreciation},0,ROR) \qquad (6.3.1)$$

The rate of return is found using Newton's method. Figure 6.3-1 displays the process graphically. The present worth of the option is found with the discount rate used by the utility. This calculation gives point A in figure 6.3-1. The derivative of the LCS_{PW} curve with respect to the discount rate, as at point A, is given by equation 6.3.2.

$$\frac{dLCS_{PW}}{dd} = B*\frac{ŽPWF(N_{life},inf,d)}{Žd} + C*\frac{ŽPWF(N_{life},0,d)}{Žd} + D*\frac{ŽPWF(N_{depreciation},0,d)}{Žd} \qquad (6.3.2)$$

The partial derivative of the present worth factor with respect to the discount rate ($\frac{ŽPWF(N,i,d)}{Žd}$) is given by equation 6.3.3.

$$\frac{ŽPWF(N,i,d)}{Žd} = \frac{N}{(1+d)} * \left(\frac{1+i}{1+d}\right)^N - \frac{PWF(N,i,d)}{(d-i)} \qquad \text{if } i \neq d$$

$$\frac{ŽPWF(N,i,d)}{Žd} = \frac{-N}{(1+d)^2} \qquad \text{if } i = d \qquad (6.3.3)$$

A new discount rate (d^{new}) is found by equating the derivative evaluated at point A to the slope of the line computed with point A and a present worth of zero.

$$\frac{dLCS_{PW}}{dd} = \frac{0 - LCS_{PW}}{d^{new} - d^{old}}$$

Rearranging the equation becomes equation 6.3.4.

$$d^{new} = \frac{-LCS_{PW}}{dLCS_{PW}/dd} + d^{old} \qquad (6.3.4)$$

This new discount rate is used to re-evaluate the present worth (point B in figure 6.3-1) and the process is repeated. A tolerance is placed on the present worth. Once the evaluation of the present worth is less than the tolerance, the iteration is stopped and the last value of d^{new} is the rate of return (point N in figure 6.3-1).

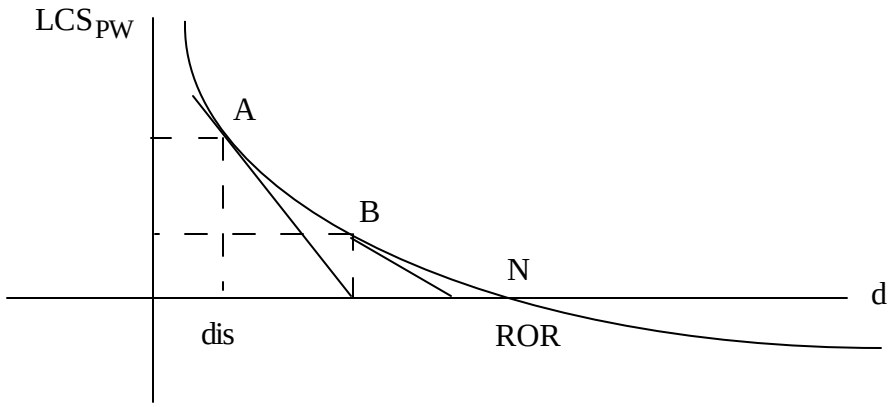

Figure 6.3-1: Graphical Representation of ROR Calculation Process

6.4 Summary

An economic model is developed to assess the savings of a solar energy DSM program. An equation that calculates the life cycle savings of the cost of serving the customer with solar energy systems relative to an entirely central generation option is developed. The economic model accounts for the costs and benefits discussed in chapter 5 as well as customer payments towards the systems and equipment depreciation. An equation to calculate the levelized life cycle savings and a method to find the rate of return are developed.

CHAPTER 7

Case Study

The software package EUSESIA, An Electric Utility Solar Energy System Impact Analysis (Trzesniewski et al., 1995) is used in a case study. EUSESIA employs the models and equations developed to this point to automate the analysis of the impact of an ensemble of solar energy systems on an electric utility. EUSESIA is broken down into three general areas of analysis: solar energy and conventional system analysis, marginal plant analysis and economic and environmental impact analysis.

A group of subprograms predicts the electric demands of solar and electric domestic hot water systems and the electric generation of a photovoltaic system. These system performances are calculated on an hourly basis for an entire year. Generic system parameters are supplied, but the user can modify the system parameters. With expertise in TRNSYS, specific solar systems that are being considered in demand-side management programs can be simulated and added to the EUSESIA analysis.

A second subprogram determines the marginal utility plant on an hourly basis given specific plant data and hourly load. The marginal plant is found on a least cost basis. The user has the ability to input data for their plant mix or regional plant data that includes neighboring utilities. The latter results in a more realistic analysis as it better represents a real market in which utilities buy and sell energy and capacity from their neighbors.

Finally, an economic and environmental impact analysis program performs calculations using information about system performance and about the marginal plant. Energy, emission and demand

reductions are quantified in terms of both physical quantities and dollars. These savings are used with the other economic benefits previously discussed to calculate the life cycle savings of the option.

7.1 Solar Energy System Performance

A one tank SDHW and a PV system are simulated to assess system performance. The default SDHW system parameters used in the simulation are summarized in table 3.1.1.2-1. The SDHW system performance is based relative to an EDHW system with default system parameters as those summarized in table 3.1.1.1-1. The default PV system parameters used in the simulation are summarized in table 3.2-2. The PV panel parameters used in the simulation are those of the Advanced Photovoltaic Systems Inc. EP-50 (table 3.2-1). The solar systems are simulated using 1991 weather data for Milwaukee, Wisconsin.

Figure 7.1-1 shows the average hourly demands of SDHW and EDHW systems with the default system parameters. The average system performance of the SDHW system is defined as the difference between the EDHW and SDHW demands. Figure 7.1-2 shows the average power generation of the default PV system. These system performances are used later for assessing the impact at the generation level.

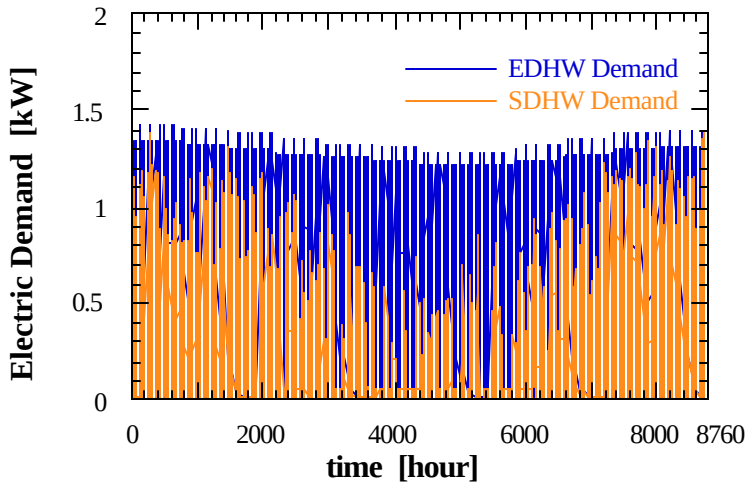

Figure 7.1-1: SDHW and EDHW System Demands

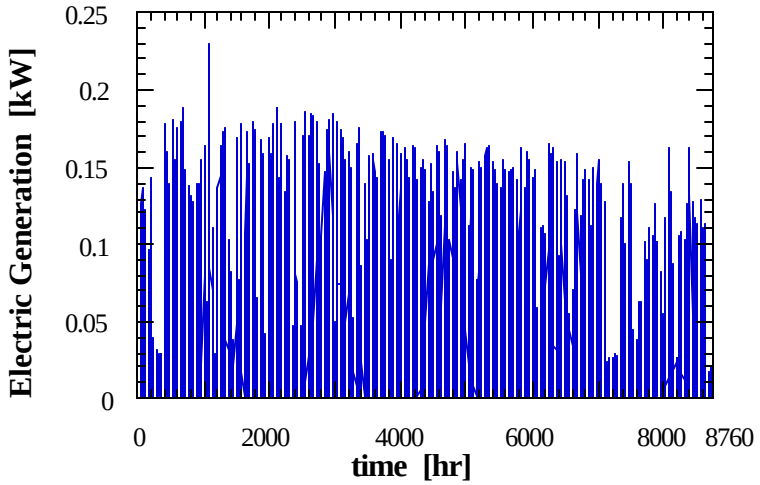

Figure 7.1-2: PV System Generation

Monthly system performance is assessed to show reductions in customer electricity use. The average demand reductions of the SDHW system and the average generation of the PV system are integrated monthly. Figure 7.1-3 shows the difference in monthly average customer electricity consumption for hot water heating between SDHW and EDHW systems. Figure 7.1-4 depicts the monthly average reduction in electricity consumption for a household with a PV system. Although the PV system generation is assumed to be connected to the grid, the electrical generation could be used by the

household. The use of the generated electricity would result in a reduction in the use of utility generated electricity.

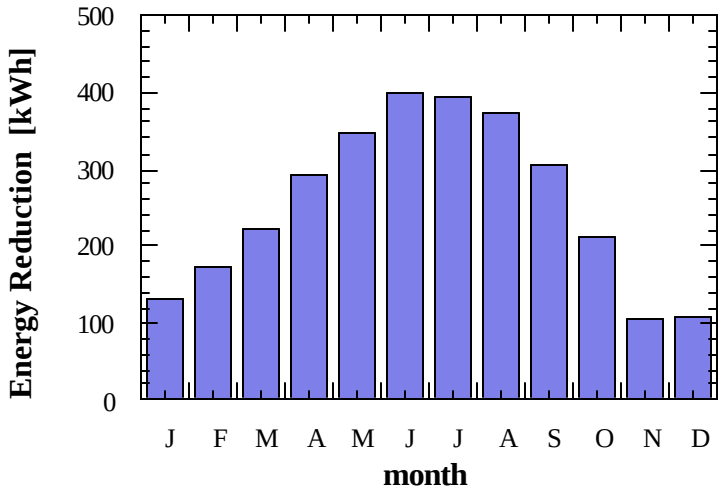

Figure 7.1-3: Average SDHW System Energy Use Reduction

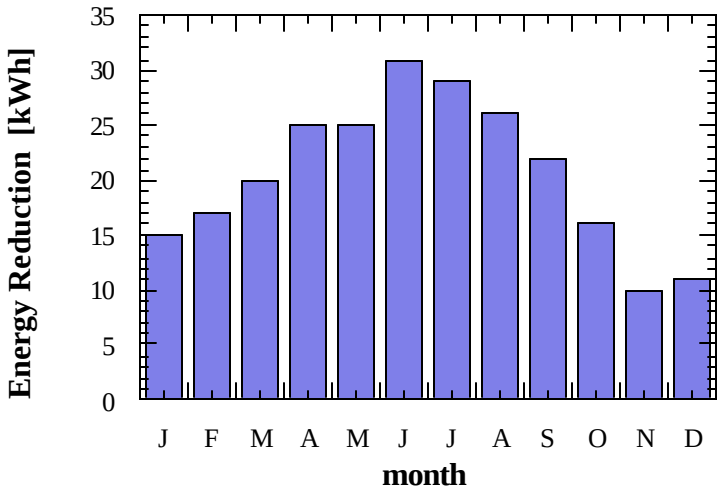

Figure 7.1-4: Average PV System Energy Use Reduction

Consumer electric bill savings are quantified with the energy reductions from the

systems and electric rate information. A summer rate of $0.0745/kWh for the months June though September and a winter rate of $0.064/kWh for the remaining months are used as typical energy costs to a residential electric customer. Using the summer and winter rates and the energy reductions previously found, the annual energy savings are found to be $211 for the SDHW system and $17 for the PV system.

7.2 Demand Method Comparison

The peak load hour and CCI methods of assessing demand reduction discussed in section 5.4 are compared. The demand methods are used to calculate the capacity contributions of the SDHW system. The demand calculations using the peak load hour are performed on a regional basis using the interconnected system load discussed in section 4.3. The CCI method is also performed on a regional basis as the marginal EUE values are calculated on a regional basis. Tables 7.2-1 and 7.2-2 show the demand reduction parameters used in the peak load hour and CCI methods of assessing demand respectively.

8/6/2002 **Table 7.2-1: Peak Load Hour Method Demand Reduction Parameters**

serve margin
[%]
st of conventional option per kW
5 [$/kW]
st of adding kW of transmission capacity
0 [$/kW]
st of adding kW of distribution capacity
0 [$/kW]
mber of peak hours to evaluate

8/6/2002 **Table 7.2-2: CCI Method Demand Reduction Parameters**

serve margin
[%]
st of conventional option per kW

5 [$/kW]
st of adding kW of transmission capacity
0 [$/kW]
st of adding kW of distribution capacity
0 [$/kW]
CI of conventional option
02

75

A typical reserve margin of 15% is used in both methods. The cost of the conventional option is given in present worth dollars per kW. This cost is representative of a combustion turbine as this is a common generation resource used to meet demand in times of high system stress. The CCI value of the combustion turbine is taken from *A Method for Comparing the Contribution of Supply-Side and Demand-Side Resources to Customer Reliability* (Harsevoort and Arny, 1994). The costs of adding an additional kW of transmission and distribution capacity are given in present worth dollars per kW.

The demand analysis is performed for 5000 solar energy systems. Table 7.2-3 shows the assessment of demand reduction given by the peak load hour and CCI methods. The demand savings are reported at the end of the first year.

8/6/2002**Table 7.2-3: Peak Load Hour and CCI Method Demand Assessments**

Method

Peak Load Hour

CCI

Capacity Contribution [kW]

3490

3529

tal Demand Savings

$119,800

$121,200

75

The peak load hour method and CCI method give nearly the same results in assessing capacity contribution and demand savings. The CCI method is a more rigorous method than the peak load hour method. The CCI method is chosen as the method of demand assessment to be used in further analysis. Marginal EUE data may not be available in all areas, so the CCI method cannot be used. The peak load hour method will provide adequate demand

assessment in such a case.

7.3 Isolated System Versus Interconnected System Analysis

The energy and emission savings of an ensemble of solar energy systems is directly related to the marginal plant at each hour of the year. What may not be as obvious is that the magnitude of the impact is affected by the defined system under investigation. Section 4.3 discusses the marginal plant predictions for WEPCO as an isolated system and an interconnected system. Energy and emission reductions and the resulting savings from an ensemble of 5000 SDHW systems are calculated for the isolated and interconnected systems. Tables 7.3-1 and 7.3-2 show the energy and emission impacts on an isolated and interconnected system respectively.

8/6/2002 **Table 7.3-1: Energy and Emission Impacts on an Isolated System**

Energy Reduction [kWh]	
Energy Savings [$]	
16,090,000	
323,200	
Emission Reduction [lbm]	
Emission Savings [$]	
CO_2	
33,600,000	
0	
SO_2	
210,600	
4,212	
NO_X	
72,550	
0	
N_2O	
565	
0	
Particulates	
4,688	

0
CH_4
533
0
77

8/6/2002**Table 7.3-2: Energy and Emission Impacts on an Interconnected System**

Energy Reduction [kWh]
Energy Savings [$]

16,090,000
261,300

Emission Reduction [lbm]
Emission Savings [$]
CO_2
18,860,000
0
SO_2
139,700
2,793
NO_X
92,770
0
N_2O
298
0
Particulates
7,961
0
CH_4
184
0

77

Energy reduction is the same for both cases as **t** is dependent on the system performance and transmission and distribution losses and not on the marginal plant. The savings due to energy reduction is greater for the isolated system than for the

interconnected system because purchases between utilities are neglected. Plants with higher marginal costs than necessary are being dispatched to meet the load. Artificially high marginal operating costs are especially apparent in the maintenance periods as shown in section 4.3.

In general, the emission reductions are greater in the isolated system than in the interconnected system because, in the isolated system, plants with higher emission rates are forced to be on sooner than would be required in the interconnected system. In the interconnected system, a greater supply of nuclear plants and cleaner coal plants are available for dispatch. These plants generally have lower operating costs and are therefore added to the generating mix before the higher cost plants with poor emission characteristics. SO_2 is the only emission for which credit is taken in this analysis. SO_2 is valued for at $0.02/lbm.

The magnitude of the energy and emission impact is affected by the system under investigation. The interconnected utility system represents a more realistic environment in which utilities buy and sell energy. The interconnected system analysis will be used in further analysis.

7.4 Utility Impact Results

The impact of an ensemble of SDHW systems is assessed for WEPCO. The analysis is performed on a regional basis and is based on 5000 SDHW systems. Figure 7.4-1 depicts the EUSESIA input file which shows the specific parameters used in the analysis.

```
C:\EUSESIA\UTILITY.TRD
                    Electric Utility Solar Energy System Impact Analysis:

                    Economic and Environmental Benefits from a Large Scale
                             Implementation of Solar Energy Systems

                            Date:                        12/95
                            Organization:                SEL
                            Input prepared by:           Trzesniewski

Utility Information
 Utility to be analyzed                                  WEPCO
 Utility region to be analyzed                           Wisconsin Utilities
 Estimate region capacity                                20000              MW

 Number of electric customers                            100000
 System transmission losses                              2.00               %
 System distribution losses                              3.00               %

Solar Energy System
 Solar system                                            Generic System: One 80 gal tank
 Installed cost of solar system                          2000               $/unit
 % of customers accepting program                        5.0                %
 Customer down payment on system                         140                $
 Customer monthly lease payment                          12.00              $/mo
 Operation, maintenance and administration               10                 $/yr-system
 Equipment depreciation period                           5                  yrs

Comparative System
 Electric System                                         Generic electric DHW system

Emission Costs
 CO2                                                     0.0000             $/lbm
 SO2                                                     0.0200             $/lbm
 NOX                                                     0.0000             $/lbm
 N2O                                                     0.0000             $/lbm
 Particulates                                            0.0000             $/lbm
 CH4                                                     0.0000             $/lbm
 Mercury                                                 0.0000             $/lbm
 Nuclear Waste                                           0.0000             $/lbm

Demand Reduction Parameters
 Reserve margin                                          15.0               %
 Cost of conventional option per kW                      325.00             $/kW
 Cost of adding kW of transmission capacity              100.00             $/kW
 Cost of adding kW of distribution capacity              100.00             $/kW
 Demand evaluation method                                System reliability using CCI method
 Number of peak hours to evaluate                        20
 CCI of conventional reference option                    0.9200

Electric Customer Retention
 % customers lost to other fuel w/o program              4                  %
 % customers lost to other fuel with program             2                  %
 Value of retained customer                              0                  $/yr

Delayed Power Plant Construction
 Value of delaying power plant construction              0                  $/peak kW

Government Incentives for Investment
 Tax credit given for investment                         10.00              %
 Energy subsidy                                          0.000              $/kWh

Economic Parameters
 Years of economic analysis                              20                 yrs
 Inflation rate                                          5.00               %
 Discount rate                                           8.00               %
 Utility tax bracket                                     34.00              %

Customer Rate Information
 Winter rate                                             0.0640             $/kWh
 Summer rate                                             0.0745             $/kWh
```

Figure 7.4-1: EUSESIA Input File Used in WEPCO Analysis

The analysis includes payments made by the customer for the solar energy

systems. For example, a program by WPS offers the solar systems to the customer for $140 down and a $12 per month lease. The installed cost of a single solar energy system is $2000. The utility is assumed to maintain ownership of the systems so that they may be depreciated. The depreciation period chosen is five years.

A utility may have reasons to credit emissions with a certain value. SO_2 has real value as WEPCO must buy credits to emit SO_2. The value assigned to SO_2 is $0.02/lbm. No other emissions are credited for in this analysis.

The CCI method is used to evaluate demand reduction. Capacity contributions at the generation level are valued relative to a combustion turbine. The present worth value of capacity contribution is given to be $325/kW. Transmission and distribution capacity contributions are each given a present worth value of $100/kW. This is the cost of adding an additional kW of capacity in each of the systems.

Customer retention and delayed power plant construction are not credited for in this analysis. Government incentives, however are included as benefits of the solar program. A ten percent tax credit is given for the initial investment in purchasing the solar energy systems.

The economic parameters are chosen to best represent WEPCO. The economic life of the SDHW systems is given as 20 years. An inflation rate of 5% and a discount rate of 8% are used in the economic calculations. The utility is assumed to be in the 34% taxbracket. Figure 7.4-2 shows the outputs from the EUSESIA analysis.

```
C:\EUSESIA\UTILITY.OUT

        Electric Utility Solar Energy System Impact Analysis:

   Impact of a Large Scale Implementation of a Solar Energy System
                        on an Electric Utility

** Energy and Environmental Impact Summary for the First Year ******
Results based on: 5000 solar systems

              Energy Reduction (kWh)            Energy Savings ($)
                  16090000                           261300

              Emission Reduction (lbm)          Emission Value ($)
       CO2        18860000                                0
       SO2          139700                             2793
       NOX           92770                                0
       N2O             298                                0
     Parts            7961                                0
       CH4             184                                0
        HG               0                                0
     NUKES               0                                0
                                                       2793

              Demand Reduction (kW)             Demand Savings ($)
                      3529                           121200

                                                Total Savings ($)
                                                     385293

** Economic Analysis Summary ***************************************

Present Worth of Investment                  -  $ 10000000
Present Worth of OM&A                        -  $   717900
Present Worth of Energy Savings                 $  3751000
Present Worth of Emission Savings               $    40110
Present Worth of Demand Savings                 $  1740000
Present Worth of Depreciation                   $  2715000
Present Worth of Downpayments                   $   700000
Present Worth of Lease Payments                 $  7069000
Present Worth of Tax Credit                     $  1000000
Present Worth of Energy Subsidy                 $        0
Present Worth of Customer Retention             $        0
Present Worth of Delay Value                    $        0

Present Worth of Life Cycle Savings             $  6297000
Levelized Savings of Option                     $   641400
Rate of Return of Option                             21.2 %

** System Performance Summary and Customer Savings *****************
Results based on average system performance

        Elc (kWh)  Sol (kWh)  Del (kWh)  SF   Savings ($)
  JAN     489        357        132     .269      8.43
  FEB     437        262        174     .399     11.16
  MAR     477        256        221     .463     14.13
  APR     449        157        293     .651     18.73
  MAY     459        114        345     .753     22.09
  JUN     439         40        399     .909     29.69
  JUL     444         51        393     .885     29.27
  AUG     444         72        371     .837     27.65
  SEP     442        135        307     .695     22.87
  OCT     463        252        212     .457     13.55
  NOV     458        352        106     .230      6.75
  DEC     478        370        109     .227      6.95

  YEAR   5477       2417       3060     .559    211.28

Option Capacity Contribution Index
          .378
```

Figure 7.4-2: EUSESIA Output File from WEPCO Analysis

The energy and environmental impact summary gives the energy, emission and

demand reductions and the resulting savings at the end of the first year of the analysis. The demand reduction reported does not include capacity contributions in the transmission and distribution systems, only capacity contributions at the generation level. The demand savings, however, do include the value of the capacity contribution to the transmission and distribution systems. The energy, emission and demand savings can be used as yearly recurring savings in an economic calculation.

Normalizing the energy, emission and demand reductions to the number of systems used in the analysis gives the average impact of a single SDHW system at the generation level. Table 7.4-1 shows the average impact of an SDHW system at the generation level.

Table 7.4-1: Average Impact of an SDHW System at the Generation Level

Energy Reduction [kWh]	
3218	
Emission Reduction [lbm]	
CO_2	3772
SO_2	27.9
NO_X	18.6
N_2O	0.0596
Particulates	1.6
CH_4	0.0368
Demand Reduction [kW]	
.71	

The present worth of the life cycle savings for the SDHW option is around 6.3 million dollars. Levelized, the life cycle savings are $641,400 per year. The rate of return of the SDHW ensemble is 21.2%. A similar analysis including only the cost of the systems, operation and maintenance costs and the energy, emission and demand savings results in a rate of return of 2.8%. The results of the economic calculation are therefore sensitive to the benefits for which credit is taken.

The system performance summary gives results based on average system performance and therefore are of interest to a typical customer. The energy requirements of the EDHW and SDHW systems and their difference are given on a monthly basis. The annual solar fraction (SF) of the SDHW system is defined to be the difference in the EDHW and SDHW energy requirements divided by the EDHW energy requirement. The solar fraction is found to be 0.56. The monthly savings are reported using the seasonal rate information discussed in section 7.1. The annual savings to a customer is $211. The capacity contribution index discussed in section 5.4 is calculated to be 0.378.

An analysis performed for an ensemble of 5000 PV systems similar to the one discussed in section 7.1, using the same input data as for the SDHW system analysis, gives annual energy savings of $21,860, emission savings of $243 and demand savings of $18,190. The rate of return calculated for the PV system is 10.8%. The average impact of a PV system at the generation level is given in table 7.4-2.

Table 7.4-2: Average Impact of a PV System at the Generation Level

Energy Reduction [kWh]	
262	
Emission Reduction [lbm]	
CO_2 344	
SO_2 2.43	
NO_X 1.45	
N_2O 0.0054	
Particulates	0.131
CH_4 0.0038	
Demand Reduction [kW]	
.10	

7.5 Summary

The software package EUSESIA is used to simulate SDHW and PV system performance and to assess the impact of an ensemble of 5000 SDHW systems on WEPCO. The CCI method of demand assessment is chosen to quantify capacity contributions. A regional analysis, considering WEPCO as an interconnected utility, is chosen for the study. The study shows energy reductions at the generation level to be slightly over 16 Gigawatt hours. Emission reductions are quantified and the total demand reduction is shown to be 3529 kW. The average capacity contribution is 0.71 kW per system. The SDHW system saves a consumer $211 per year on electric bills. A similar study for a PV system shows about 1.7 Gigawatt hours of energy reduction and a demand reduction of 530 kW. The PV system saves a consumer approximately $17 per year on electric bills. SDHW systems have a larger impact on a utility than PV systems with comparable array areas. SDHW systems also offer consumers greater savings on electric bills. When considering only the energy, emission and demand savings and costs of the system and operation and maintenance, the rate of return is calculated to be 2.8%. By including customer payments, equipment depreciation and government incentives in the economic analysis gives a rate of return of 21.2%.

CHAPTER 8

Conclusions and Recommendations

8.1 Conclusions

A large scale implementation of solar energy systems has significant impact on an electric utility. On average, an SDHW system consisting of a 60 ft^2 collector and a single 80 gallon tank realizes annual energy reductions at the utility level of 3218 kWh, emission reductions of: 3772 lbm CO_2, 27.9 lbm SO_2, 18.6 lbm NO_X, 0.0596 lbm N_2O, 1.6 lbm particulates and 0.0368 lbm CH_4 and demand reduction of 0.71 kW. A PV system of comparable array area shows substantially less impact.

The annual savings resulting from an ensemble of 5000 SDHW systems are $261,300 in energy reduction, $2,793 in emission reduction and $121,200 in demand reduction. The emission savings are negligible compared to the energy and demand savings, but may be more substantial in the future as emission regulations become tougher.

An economic analysis shows the rate of investment to be 2.8% when considering only the energy, emission and demand savings and the costs of the systems and annual operation and maintenance costs. When customer payments, equipment depreciation and government incentives are included in the economic analysis, however, the rate of investment is calculated to be 21.2%. The results of economic analysis are dependent on the benefits for which the utility takes credit.

An annual analysis performed on an hourly basis is required to accurately assess the impact of an ensemble of solar energy systems on an electric utility. Energy savings

and emission reduction are dependent on the operating costs and emission characteristics of the marginal plant, which varies hourly. Hourly weather and load data from the same year must be supplied to accurately assess the demand reduction of an ensemble of solar energy systems. For most accurate results, the analysis should be performed on a regional basis. Considering the utility as part of an interconnected system of utilities represents a more realistic environment, in which utilities buy and sell energy and demand from one another, than considering the utility as an isolated system.

8.2 Recommendations

The analysis in this research is performed with weather and load information from 1991. It would be useful to perform the analysis with weather and load information from other years to see if the analyses yield similar results. A database containing hourly weather data for various locations throughout the country would be useful for assessing solar performance in other areas. A database containing hourly load and plant data for all utilities, similar to that of the Federal Energy Regulatory Commission, would help utilities gather the necessary information to perform regional analyses.

An accessible library containing models of other solar energy system configurations would offer a user an analysis of more detailed solar energy systems. A model has been developed to assess demand requirements of a solar energy system containing collectors rated by the Solar Rating & Certification Corporation (SRCC). A file containing the parameters of a few SRCC rated collectors is available with the model. This file could be modified to contain all the collectors rated by the SRCC.

The analysis is not limited to demand-side resources. The impact of a supply-side resource, such as a wind turbine, could be assessed with EUSESIA. A model producing hourly wind turbine generation is required for the analysis. Transmission and distribution losses are not considered when assessing a supply-side resource. Similar to the PV

analysis there would be no comparative system in assessing wind turbines as it is a generating resource.

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APPENDIX A

Utility Load and Plant Data

Wisconsin Electric Power Company (WEPCO)

Wisconsin Public Service Corporation (WPS)

Wisconsin Power and Light Company (WPL)

Madison Gas and Electric (MG&E)

Northern States Power Company (NSP)

Dairyland Power Cooperative (DPC)

Six Utility Region

Wisconsin Electric Power Company

Table B-1: WEPCO Plant Data

A: 37 B: plant C: capacity [MW] D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 sta rt (mm/dd) G: outage 2 end (mm/dd)
H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%]
M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%] Q: partial capacity 4 [MW]
R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh] V: N2O [lbm/MWh] W: Particulates [lbm/MWh]
X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
1	'PNT BEACH2'	497	3	1	5	1	9	20	11	20	6	1.9	0	0	0	0	0	0	0.0048	0	0	0	0	0	0
2	'PNT BEACH1'	497	3	1	5	1	9	20	11	20	6	1.9	0	0	0	0	0	0	0.0048	0	0	0	0	0	0
15	'PLEASNTPR2'	580	3	1	5	1	9	20	11	20	6	1	1.3	220	0	0	0	0	0	0.009	2313	8.11	4.32	0.0184	0.108	0.014	0	0
16	'PLEASNTPR1'	580	3	1	5	1	9	20	11	20	6	1	1.3	220	0	0	0	0	0	0.009	2313	8.11	4.32	0.0184	0.108	0.014	0	0
26	'EDGEWATER5'	97	3	1	5	1	9	20	11	20	4	2	5	38	0	0	0	0	0	0.0136	0	0	0	0	0	0
3	'OAK CREEK8'	305	3	1	5	1	9	20	11	20	5	1	1.6	85	0	0	0	0	0	0.0143	1868	7.6	2.56	0.0165	0.183	0.01	0	0
4	'OAK CREEK7'	280	3	1	5	1	9	20	11	20	5	1	1.6	85	0	0	0	0	0	0.0143	1868	7.6	2.56	0.0165	0.183	0.01	0	0
6	'OAK CREEK5'	258	3	1	5	1	9	20	11	20	5	2	2.9	82	0	0	0	0	0	0.0148	1904	7.75	2.61	0.0168		0.187	0.01	0	0
5	'OAK CREEK6'	260	3	1	5	1	9	20	11	20	5	2	3	82	0	0	0	0	0	0.0149	1907	7.76	2.62	0.0168	0.187	0.01	0	0
22	'PRESQUEIS4'	57	3	1	5	1	9	20	11	20	1	1	2.4	12	0	0	0	0	0	0.0162	2250	16.63	6.5	0.0160	0.426	0.012	0	0			
20	'PRESQUEIS6'	85	3	1	5	1	9	20	11	20	1	1	2.2	20	0	0	0	0	0	0.0163	2237	16.54	8.9	0.0159	0.424	0.012	0	0			
21	'PRESQUEIS5'	84	3	1	5	1	9	20	11	20	1	1	2.2	19	0	0	0	0	0	0.0163	2238	16.55	8.91	0.0159		0.318	0.012	0	0		
25	'PRESQUEIS1'	25	3	1	5	1	9	20	11	20	0	0	0	0	0	0	0	0	0.0165	3381	19.23	13.46	0.024	0.321	0.018	0	0					
24	'PRESQUEIS2'	37	3	1	5	1	9	20	11	20	0	0	0	0	0	0	0	0	0.0167	3028	22.39	12.05	0.0215	1.292	0.016	0	0					
23	'PRESQUEIS3'	58	3	1	5	1	9	20	11	20	1	1	2.4	12	0	0	0	0	0	0.017	2250	16.63	6.5	0.016	0.32	0.012	0	0			
9	'PORT WASH2'		80	3	1	5	1	9	20	11	20	0	4	1.3	29	0	0	0	0	0	0.0199	2167	23.34	3.75	0.0156		0.417	0.166	0	0		
10	'PORT WASH1'		80	3	1	5	1	9	20	11	20	0	4	1.3	29	0	0	0	0	0	0.0203	2237	24.09	3.87	0.0161		0.43	0.171	0	0		
13	'VALLEY2 '		62	3	1	5	1	9	20	11	20	8		2.5	3.9	30	0	0	0	0	0.0214	2436	26.58	5.86	0.0222		0.586	0.013	0	0		
11	'VALLEY4 '		70	3	1	5	1	9	20	11	20	0		2.5	4	34	0	0	0	0	0.0216	2436	26.58	5.86	0.0222		0.586	0.013	0	0		
14	'VALLEY1 '		64	3	1	5	1	9	20	11	20	8	1	13	7	0	0	0	0	0	0.0224	2557	27.91	6.15	0.0234	0.615	0.014	0	0			
17	'PRESQUEIS9'	84		3	1	5	1	9	20	11	20	1	1	3	14	0	0	0	0	0	0.0227	2392	12.54	8.05	0.0173	0.23	0.014	0	0			
18	'PRESQUEIS8'	83		3	1	5	1	9	20	11	20	1	1	3	14	0	0	0	0	0	0.0227	2392	12.53	8.05	0.0172	0.23	0.014	0	0			
19	'PRESQUEIS7'	81		3	1	5	1	9	20	11	20	1	1	3.2	13	0	0	0	0	0	0.0227	2392	12.53	8.05	0.0172		0.23	0.014	0	0		
12	'VALLEY3 '		70	3	1	5	1	9	20	11	20	0	1	15	14	0	0	0	0	0	0.023	2436	26.58	5.86	0.0222	0.586	0.013	0	0			
8	'PORT WASH3'		82	3	1	5	1	9	20	11	20	0	4	1.4	29	0	0	0	0	0	0.0237	2155	32.2	3.73	0.0155		0.414	0.165	0	0		
7	'PORT WASH4'		80	3	1	5	1	9	20	11	20	0	4	1.5	29	0	0	0	0	0	0.0267	2492	26.84	4.31	0.018	0.479	0.191	0	0			
27	'CONCORD4 '	83		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.047	1609	0	1.16	0.1803	0	0.004	0	0				
28	'CONCORD3 '	83		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.047	1609	0	1.16	0.1803	0	0.004	0	0				
29	'CONCORD2 '	83		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.047	1609	0	1.16	0.1803	0	0.004	0	0				
30	'CONCORD1 '	83		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.047	1609	0	1.16	0.1803	0	0.004	0	0				
35	'OAK CREEK9'	20		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.055	7	3296	41.6	13.6	0.16	0.8	0	0	0			
31	'GERMNTOWN4'		53	3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.06	3296	41.6	13.6	0.16	0.8	0	0	0			
32	'GERMNTOWN3'		53	3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.06	3296	41.6	13.6	0.16	0.8	0	0	0			
33	'GERMNTOWN2'		53	3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.06	3296	41.6	13.6	0.16	0.8	0	0	0			
34	'GERMNTOWN1'		53	3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.06	3296	41.6	13.6	0.16	0.8	0	0	0			
36	'PNT BEACH5'	20		3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.063	7	3296	41.6	13.6	0.16	0.8	0	0	0			
37	'PORT WASH6'		18	3	1	5	1	9	20	11	20	0	1	0	0	0	0	0	0	0.065	1	3296	41.6	13.6	0.16	0.8	0	0	0			

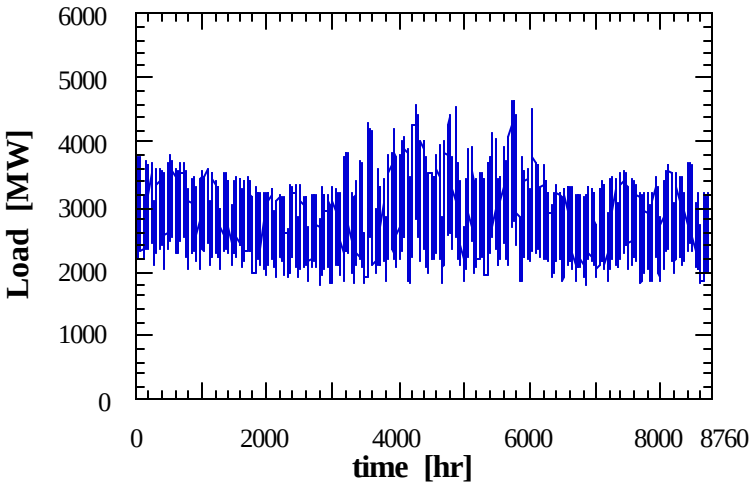

Figure B-1: WEPCO 1991 Load

Wisconsin Public Service Corporation

Table B-2: WPS Plant Data

A: 19B: plant C: capacity [MW]D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%]Q: partial capacity 4 [MW] R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh]V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	DE	FG	H	I	J	K	L	M	N	O	P	QR	S	T	U	V	W	X	Y	Z
1	'KEWAUNEE1 '	212	3	1	5	1	9	1	11	1	6	1.7	0	0	0	0	0.0053	0	0	0	0	0
9	'WESTON2 '	92	3	1	5	1	9	1	11	1	2	50	15	0	0	0	0.0109	2170	8.5	12.54	0.032	0.21
11	'COLUMBIA2 '	1583	1	5	1	9	1	11	1	5	70	58	0	0	0	0	0.0113	2196	13.82	4.95	0.031	0.52
13	'EDGEWATER4'	104	3	1	5	1	9	1	11	1	5	60	34	0	0	0	0.0113	1986	19.48	18.81	0.096	0.96
12	'COLUMBIA1 '	1623	1	5	1	9	1	11	1	5	60	48	0	0	0	0	0.0118	2226	5.75	3.55	0.031	0.21
8	'WESTON3 '	3373	1	5	1	9	1	11	1	4	50	59	0	0	0	0	0.0119	2074	8.13	12.09	0.03	0.3
10	'WESTON1 '	68	3	1	5	1	9	1	11	1	2	50	12	0	0	0	0.0121	2381	8.19	2.5	0.034	0.34
2	'PULIAM8 '	135	3	1	5	1	9	1	11	1	2	50	25	0	0	0	0.0137	2043	17.2	8.75	0.031	1.32
3	'PULIAM7 '	88	3	1	5	1	9	1	11	1	2	50	16	0	0	0	0.014	2081	17.52	8.92	0.031	0.73
4	'PULIAM6 '	67	3	1	5	1	9	1	11	1	2	50	14	0	0	0	0.0162	2387	11.06	12.6	0.036	0.24
5	'PULIAM5 '	52	3	1	5	1	9	1	11	1	2	50	16	0	0	0	0.0167	2432	11.27	12.84	0.036	0.36
7	'PULIAM3 '	26	3	1	5	1	9	1	11	1	2	18	0	14	0	0	0	0.0242	2543	11.78	13.43	0.038
6	'PULIAM4 '	27	3	1	5	1	9	1	11	1	2	18	0	15	0	0	0	0.0253	2672	12.38	14.11	0.04
18	'WMARINTT33'	75	3	1	5	1	9	1	11	1	2	4.3	0	19	0	0	0	0.0355	0	0	0	0
15	'WESTON32 '	50	3	1	5	1	9	1	11	1	1	50	14	0	0	0	0.0417	2658	10.42	15.36	0.039	0.26
17	'WMARINTT32'	40	3	1	5	1	9	1	11	1	1	50	9	0	0	0	0.0425	0	0	0	0	0
16	'WMARINTT31'	40	3	1	5	1	9	1	11	1	1	50	11	0	0	0	0.0427	0	0	0	0	0
14	'WESTON31 '	20	3	1	5	1	9	1	11	1	2	50	50	0	0	0	0.0483	3276	12.84	18.94	0.048	0.32
19	'EAGLERIVR1'	4	3	1	5	1	9	1	11	1	0	50	0	0	0	0	0.0552	0	0	0	0	0

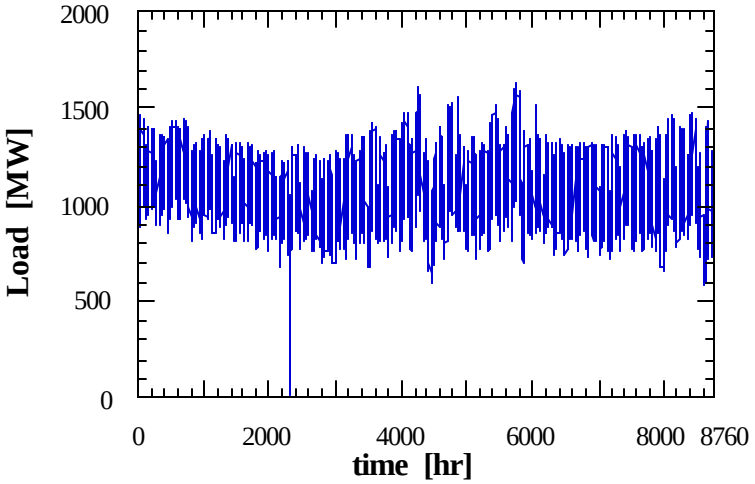

Figure B-2: WPS 1991 Load

Wisconsin Power and Light Company

Table B-3: WPL Plant Data

A: 16B: plant C: capacity [MW]D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%]Q: partial capacity 4 [MW] R: operating cost [$/MWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh]V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	DE	FG	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
16	'KEWAUNEE1 '	214	3	1	5	1	9	1	11	1	6	3.4	0	0	0	0	0.0076	0	0	0	0	0	0
2	'COLUMBIA2 '	2363	1	5	1	9	1	11	1	5	7.8	0	0	0	0	0	0.011	2195	5.67	3.5	0.011	0.206	0.018	0	0
4	'EDGEWATER4'	217	3	1	5	1	9	1	11	1	4	5.4	0	0	0	0	0.0124	1991	19.53	18.86	0.118	0.957	0.014	0	0
5	'EDGEWATER5'	294	3	1	5	1	9	1	11	1	4	2.5	0	0	0	0	0.0129	2165	6.71	3.76	0.011	0	0.017	0	0
7	'NLSNDEWEY2'	111	3	1	5	1	9	1	11	1	4	2.4	0	0	0	0	0.0136	2123	7.54	9.19	0.126	1.838	0.015	0	0
6	'NLSNDEWEY1'	108	3	1	5	1	9	1	11	1	4	8.1	0	0	0	0	0.0137	2150	7.54	8.47	0.127	0.62	0.016	0	0
1	'COLUMBIA1 '	2373	1	5	1	9	1	11	1	5	8	0	0	0	0	0	0.0141	2207	13.89	4.97	0.011	0.518	0.018	0	0
8	'ROCKRIVER1'	73	3	1	5	1	9	1	11	1	4	1.6	0	0	0	0	0.0141	2134	29.76	14.16	0.126	1.026	0.014	0	0
9	'ROCKRIVER2'	74	3	1	5	1	9	1	11	1	4	5.7	0	0	0	0	0.0143	2167	30.21	19.27	0.128	1.667	0.015	0	0
3	'EDGEWATER3'	70	3	1	5	1	9	1	11	1	4	3.1	0	0	0	0	0.0158	2383	23.37	22.46	0.141	1.146	0.017	0	0
15	'BLACKHAWK4'	28	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.039	1362	0.12	17.93	0.047	0	0.003	0	0
14	'BLACKHAWK3'	27	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.0404	1418	0.12	16.73	0.048	0	0.004	0	0
12	'ROCKRIVER5'	46	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.0433	1452	0.12	51.25	0.05	0	0.004	0	0
13	'ROCKRIVER6'	44	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.0436	1463	0.13	51.63	0.05	0	0.004	0	0
11	'ROCKRIVER4'	13	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.0511	1837	0.16	64.83	0.063	0	0.005	0	0
10	'ROCKRIVER3'	25	3	1	5	1	9	1	11	1	0	4.3	0	0	0	0	0.0581	2069	0.18	73.03	0.071	0	0.005	0	0

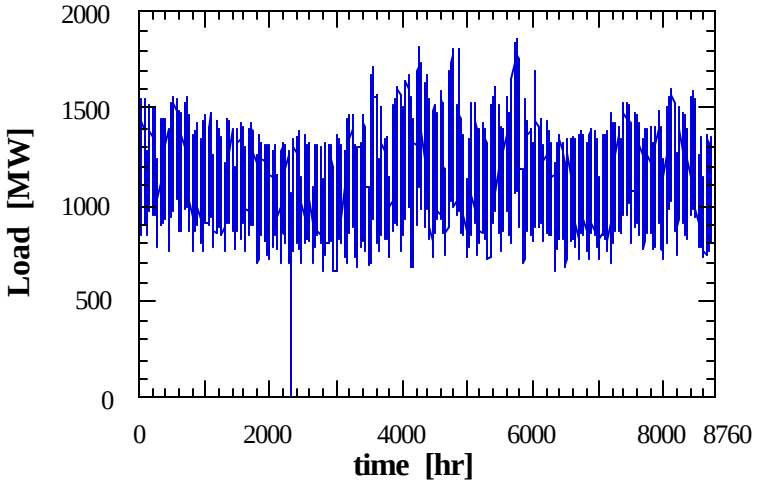

Figure B-3: WPL 1991 Load

Madison Gas and Electric

Table B-4: MG&E Plant Data

A: 16B: plant C: capacity [MW]D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%]Q: partial capacity 4 [MW] R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh]V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	DE	FG	HI	JK	LM	N	OP	QR	S	TU	VW	X	YZ													
1	'KEWAUNEE	'93	3 1	5 1	9 1		11 1	6	1.1	0		0 0	0 0	0	0 0	0.0048	0 0	0 0	0 0	0								
3	'COLUMBIA2 '	1113	1 5	1 9	1		11 1	5	1	15.5	96	0 0		0 0		0 0	0.0117	2195	5.67	3.5	0.011		0.206	0.018	0 0			
2	'COLUMBIA1 '	1133	1 5	1 9	1		11 1	5	4.1	15.5	88	0 0		0 0		0 0	0.0183	2207	13.89	4.97	0.011		0.518	0.018	0 0			
16	'CCS(NEW)	'1203	1 5	1 9	1	11 1	2		5.5	0		0 0	0 0	0	0 0	0.0201	9990	0.24	0.11	0 0	0.064	0		0				
8	'BLOUNT6T8B50		3 1	5 1	9 1		11 1	3	7.5	0		0 0	0 0	0	0 0	0.0283	2575	15	10	0.13	0.38	0		0		0		
9	'BLOUNT7T9B49		3 1	5 1	9 1		11 1	3	2.3	0		0 0	0 0	0	0 0	0.0283	2575	15	10	0.13	0.38	0		0		0		
15	'CTS(NEW)	'40	3 1	5 1	9 1	11 1	1		3.5	0		0 0	0 0	0	0 0	0.0292	1525	0	1.098	0.17	0	0.122		0		0		
10	'FITCHBURG1'	'21	3 1	5 1	9 1		11 1	1	15	0		0 0	0 0	0	0 0	0.0309	1584	0	5.459	0.13	13	0	0					
11	'FITCHBURG2'	'21	3 1	5 1	9 1		11 1	1	15	0		0 0	0 0	0	0 0	0.0309	1588	0	5.472	0.13	0.13	0		0		0		
14	'NINESPRNGS'	14	3 1	5 1	9 1	11 1	1	1	15	0		0 0	0 0	0	0 0	0.0313	1581	0	5.446	0.13	0.13	0		0		0		
13	'SYCAMORE2 '	20	3 1	5 1	9 1	11 1	1	1	15	0		0 0	0 0	0	0 0	0.0328	1699	0	5.855	0.14	0.14	0		0		0		
12	'SYCAMORE1 '	14	3 1	5 1	9 1	11 1	1	1	15	0		0 0	0 0	0	0 0	0.0346	1809	0	6.232	0.15	0.15	0		0		0		
6	'BLOUNT5&6B38		3 1	5 1	9 1		11 1	2	3	0		0 0	0 0	0	0 0	0.0371	1955	0	4.6	0.16		0 0	0 0					
7	'BLOUNT7B '	23	3 1	5 1	9 1		11 1	2	3	0		0 0	0 0	0	0 0	0.0371	3386	57.53	13.15	0.16	0.49		0		0	0		
5	'BLOUNT3&11'	'27	3 1	5 1	9 1		11 1	2	3	0		0 0	0 0	0	0 0	0.0374	1969	0	4.634	0.17	0	0 0	0					
4	'BLOUNT1&2B6		3 1	5 1	9 1	11 1	1		20	0		0 0	0 0	0	0 0	0.0417	2261	0	5.32	0.19	0	0 0	0					

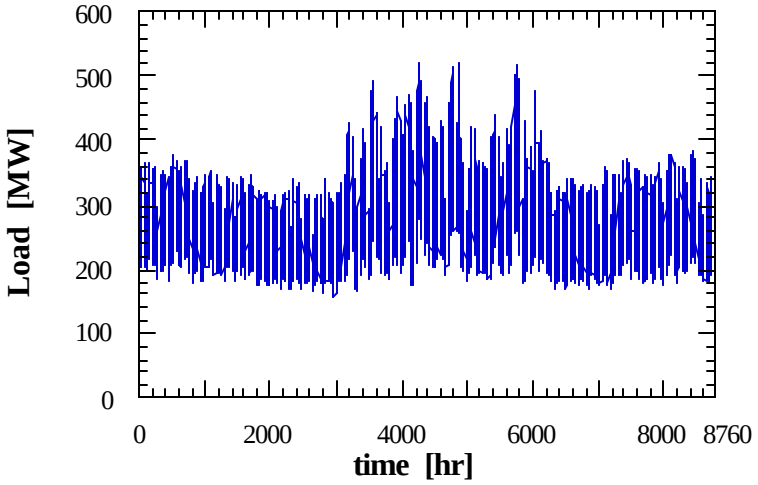

Figure B-4: MG&E 1991 Load

Northern States Power Company

Table B-5: NSP Plant Data

A: 28B: plant C: capacity [MW]D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%]Q: partial capacity 4 [MW] R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh]V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	DE	FG	HI	JK	LM	N	OP	QR	S	TU	VW	X	YZ													
26	'PRAIRIEIS2'	524	3 1	5 1	9 1	11 1	4		3	0	0	0 0	0 0	0	0 0	0.0051	0	0		0 0	0 0	0 0						
25	'PRAIRIEIS1'	524	3 1	5 1	9 1	11 1	4		3	0	0	0 0	0 0	0	0 0	0.0054	0	0		0 0	0 0	0 0						
24	'MONTICELLO'	552	3 1	5 1	9 1		11 1	4	5	0	0 0	0 0	0		0 0		0.0059	0	0 0	0 0	0 0	0						
15	'RED WING2 '	12	3 1	5 1	9 1		11 1	4	10	0	0 0	0 0	0		0 0		0.0114	0	4.66	5.466	0 0.64	0 0	0					
14	'RED WING1 '	12	3 1	5 1	9 1		11 1	4	10	0	0 0	0 0	0		0 0		0.0119	0	4.88	5.718	0 0.67	0 0	0					
1	'A.S.KING '	574	3 1	5 1	9 1	11 1	5		7	0	0	0 0	0 0	0	0 0	0.0125	0	15.17	8.255	0 0.29	0 0	0						
4	'SHERBURNE3'	871	3 1	5 1	9 1	11 1	3	5		0	0	0 0	0 0	0	0 0		0.0125	0	2.53	3.991	0 0.49	0 0	0					
27	'OIL CTS '	111	3 1	5 1	9 1	11 1	0		15	0	0	0 0	0 0	0	0 0		0.0138	0	0.6	0.255	0 0.02	0 0	0					
28	'GAS CTS '	186	3 1	5 1	9 1	11 1	0		40	0	0	0 0	0 0	0	0 0		0.0138	0	7.65	1.2	0 0.15	0 0	0					
2	'SHERBURNE1'	712	3 1	5 1	9 1	11 1	2	3		0	0	0 0	0 0	0	0 0		0.0142	0	2.72	4.289	0 0.52	0 0	0					
5	'RIVERSIDE8'	215	3 1	5 1	9 1		11 1	4	15	0	0	0 0	0 0	0	0 0		0.0142	0	4	9.79	0 0.8	0 0	0					
3	'SHERBURNE2'	712	3 1	5 1	9 1	11 1	2	5		0	0	0 0	0 0	0	0 0		0.0143	0	2.72	4.289	0 0.52	0 0	0					
12	'HIGHBRDGE6'	169	3 1	5 1	9 1	11 1	2	18		0	0	0 0	0 0	0	0 0		0.0154	0	4.65	6.767	0 0.95	0 0	0					
6	'RIVERSIDE7'	130	3 1	5 1	9 1		11 1	2	10	0	0	0 0	0 0	0	0 0		0.0161	0	4.6	11.262	0 0.92	0 0	0					
11	'HIGHBRDGE5'	93	3 1	5 1	9 1	11 1	2	10		0	0	0 0	0 0	0	0 0		0.0162	0	4.94	7.183	0 1.01	0 0	0					
10	'BLACKDOG4 '	176	3 1	5 1	9 1		11 1	2	20	0	0	0 0	0 0	0	0 0		0.0164	0	6.55	8.411	0 0.33	0 0	0					
16	'WILMARTH1 '	11	3 1	5 1	9 1		11 1	4	10	0	0	0 0	0 0	0	0 0		0.0165	0	2.81	5.286	0 0.5	0 0	0					
8	'BLACKDOG2 '	100	3 1	5 1	9 1		11 1	2	35	0	0	0 0	0 0	0	0 0		0.0167	0	6.7	8.604	0 0.34	0 0	0					
9	'BLACKDOG3 '	110	3 1	5 1	9 1		11 1	2	15	0	0	0 0	0 0	0	0 0		0.0167	0	6.72	8.622	0 0.34	0 0	0					
7	'BLACKDOG1 '	78	3 1	5 1	9 1		11 1	2	15	0	0	0 0	0 0	0	0 0		0.0176	0	7.18	9.218	0 0.36	0 0	0					
17	'WILMARTH2 '	11	3 1	5 1	9 1		11 1	4	10	0	0	0 0	0 0	0	0 0		0.0176	0	2.99	5.635	0 0.53	0 0	0					
13	'MINNVALLEY'	48	3 1	5 1	9 1		11 1	2	15	0	0	0 0	0 0	0	0 0		0.0181	0	10.29	6.15	0 0.53	0 0	0					
20	'BAYFRONT6 '	30	3 1	5 1	9 1		11 1	4	7	0	0	0 0	0 0	0	0 0		0.0223	0	5.94	7.701	0 2.57	0 0	0					
19	'BAYFRONT5 '	23	3 1	5 1	9 1		11 1	4	7	0	0	0 0	0 0	0	0 0		0.0232	0	6.25	8.105	0 2.7	0 0	0					
22	'FRENCH IS2'	14	3 1	5 1	9 1		11 1	2	7	0	0	0 0	0 0	0	0 0		0.0233	0	1.43	6.537	0 1.28	0 0	0					
21	'FRENCH IS1'	15	3 1	5 1	9 1		11 1	2	7	0	0	0 0	0 0	0	0 0		0.0236	0	1.46	6.642	0 1.3	0 0	0					
18	'BAYFRONT4 '	20	3 1	5 1	9 1		11 1	4	7	0	0	0 0	0 0	0	0 0		0.0248	0	6.78	8.793	0 2.93	0 0	0					
23	'PATHFINDER'	64	3 1	5 1	9 1		11 1	2	20	0	0	0 0	0 0	0	0 0		0.0481	0	0	5.118	0 0.12	0 0	0					

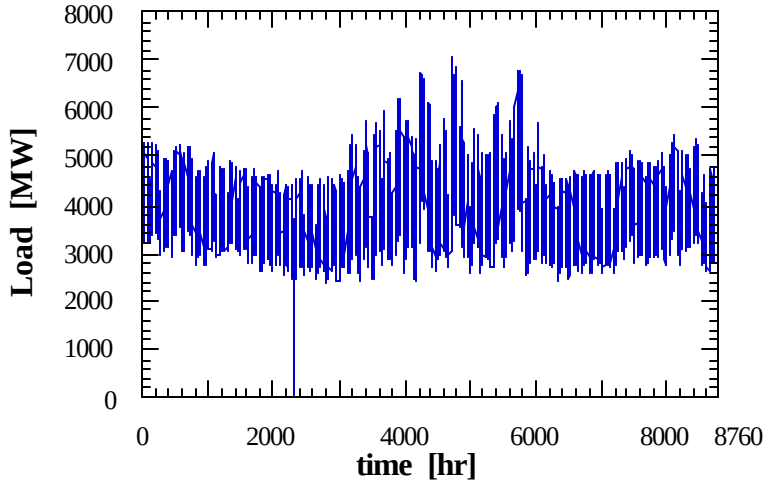

Figure B-5: NSP 1991 Load

Dairyland Power Cooperative

Table B-6: DPC Plant Data

A: 8 B: plant C: capacity [MW] D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%] Q: partial capacity 4 [MW] R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh] V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	DE	FG	HI	JK	LM	N	OP	QR	S	T	UV	W	X	YZ
8	'FLAMBEAU '	21	3 1	5 1	9 1		11 1	0 0		0	0	0 0	0 0	0	0	0 0
7	'GENOA3 '	3763	1 5	1 9	1 11	1 4	12	0		0	0	0 0	0 0	0	0	0 0.01769
6	'JPM1 '	3743	1 5	1 9	1 11	1 4	4 0	0 0		0	0	0 0	0 0	0	0.01883	1831
1	'ALMA1 '	20	3 1	5 1	9 1	11 1	1 7.69	0		0	0	0 0	0 0	0	0	0 0.02493
2	'ALMA2 '	22	3 1	5 1	9 1	11 1	1 7.69	0		0	0	0 0	0 0	0	0	0 0.02493
3	'ALMA3 '	21	3 1	5 1	9 1	11 1	1 7.69	0		0	0	0 0	0 0	0	0	0 0.02493
4	'ALMA4 '	59	3 1	5 1	9 1	11 1	2 4.6	0 0		0	0	0 0	0 0	0		0.02493
5	'ALMA5 '	85	3 1	5 1	9 1	11 1	2 3.1	0 0		0	0	0 0	0 0	0		0.02493

A	B	DE	FG	HI	JK	LM	N	OP	QR	S	T	UV	W	X	YZ
8	'FLAMBEAU '	0.00457	0 0	0 0	0 0	0 0									
7	'GENOA3 '	2183	14.98	8.56	0.03	1.61	0.011	0	0						
6	'JPM1 '	1831	6.55	4.2	0.03	0.25	0.008	0 0							
1	'ALMA1 '	2797	26.64	12.65	0.04	0.13	0.01	0	0						
2	'ALMA2 '	2797	26.64	12.65	0.04	0.13	0.01	0	0						
3	'ALMA3 '	2797	26.64	12.65	0.04	0.13	0.01	0	0						
4	'ALMA4 '	2333	22.22	10.55	0.03	0.11	0.011	0	0						
5	'ALMA5 '	2209	21.04	9.99	0.03	0.21	0.011	0	0						

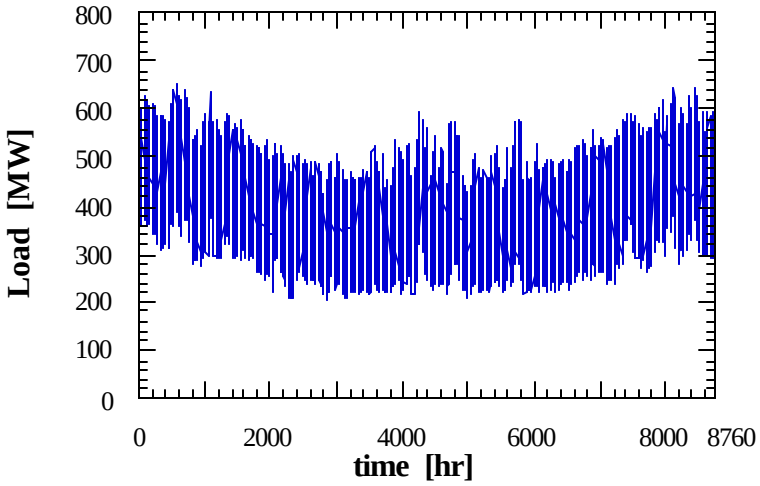

Figure B-6: DPC 1991 Load

Six Utility Region

Table B-7: Regional Plant Data

A: 124 B: plant C: capacity [MW] D: outage1 start (mm/dd) E: outage 1 end (mm/dd) F: outage 2 start (mm/dd) G: outage 2 end (mm/dd) H: scheduled outage [wks] I: full outage [%] J: partial outage 1 [%] K: partial capacity 1 [MW] L: partial outage 2 [%] M: partial capacity 2 [MW] N: partial outage 3 [%] O: partial capacity 3 [MW] P: partial outage 4 [%] Q: partial capacity 4 [MW] R: operating cost [$/kWh] S: CO2 [lbm/MWh] T: SO2 [lbm/MWh] U: NOX [lbm/MWh] V: N2O [lbm/MWh] W: Particulates [lbm/MWh] X: CH4 [lbm/MWh] Y: Mercury [lbm/MWh] Z: Nuclear Waste [lbm/MWh]

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
8	'FLAMBEAU '	21	3	1	5	1	9	20	11	20	0	0	0	0	0	0	0	0	0	0.00457	0	0	0	0	0
9	'KEWAUNEE '	93	3	1	5	1	9	20	11	20	6	1.1	0	0	0	0	0	0	0	0.0048	0	0	0	0	0
53	'PNT BEACH2'	497	3	1	5	1	9	20	11	20	6	1.9	0	0	0	0	0	0	0	0.0048	0	0	0	0	0
54	'PNT BEACH1'	497	3	1	5	1	9	20	11	20	6	1.9	0	0	0	0	0	0	0	0.0048	0	0	0	0	0
50	'PRAIRIEIS2'	524	3	1	5	1	9	20	11	20	4	3	0	0	0	0	0	0	0	0.0051	0	0	0	0	0
106	'KEWAUNEE1 '	212	3	1	5	1	9	20	11	20	6	1.7	0	0	0	0	0	0	0	0.0053	0	0	0	0	0
49	'PRAIRIEIS1'	524	3	1	5	1	9	20	11	20	4	3	0	0	0	0	0	0	0	0.0054	0	0	0	0	0
48	'MONTICELLO'	552	3	1	5	1	9	20	11	20	4	5	0	0	0	0	0	0	0	0.0059	0	0	0	0	0
105	'KEWAUNEE1 '	214	3	1	5	1	9	20	11	20	6	3.4	0	0	0	0	0	0	0	0.0076	0	0	0	0	0
67	'PLEASNTPR2'	580	3	1	5	1	9	20	11	20	6	1	1.3	22	0	0	0	0	0	0.009	23	13	8.11	4.32	0.018
68	'PLEASNTPR1'	580	3	1	5	1	9	20	11	20	6	1	1.3	22	0	0	0	0	0	0.009	23	13	8.11	4.32	0.018
114	'WESTON2 '	92	3	1	5	1	9	20	11	20	2	5	0	15	0	0	0	0	0	0.0109	21	70	8.5	12.54	0.032
91	'COLUMBIA2 '	236	3	1	5	1	9	20	11	20	5	7.8	0	0	0	0	0	0	0	0.011	21	95	5.67	3.5	0.011
116	'COLUMBIA2 '	158	3	1	5	1	9	20	11	20	5	7	0	58	0	0	0	0	0	0.0113	21	96	13.8	24.95	0.031
118	'EDGEWATER4'	104	3	1	5	1	9	20	11	20	5	6	0	34	0	0	0	0	0	0.0113	19	86	19.48	18.81	0.096
39	'RED WING2 '	12	3	1	5	1	9	20	11	20	4	10	0	0	0	0	0	0	0	0.0114	0	4.66	5.46	6	0
11	'COLUMBIA2 '	111	3	1	5	1	9	20	11	20	5	1	15.5	96	0	0	0	0	0	0.0117	21	95	5.67	3.5	0.011
117	'COLUMBIA1 '	162	3	1	5	1	9	20	11	20	5	6	0	48	0	0	0	0	0	0.0118	22	26	5.75	3.55	0.031
38	'RED WING1 '	12	3	1	5	1	9	20	11	20	4	10	0	0	0	0	0	0	0	0.0119	0	4.88	5.71	8	0
113	'WESTON3 '	337	3	1	5	1	9	20	11	20	4	5	0	59	0	0	0	0	0	0.0119	20	74	8.13	12.09	0.03
115	'WESTON1 '	68	3	1	5	1	9	20	11	20	2	5	0	12	0	0	0	0	0	0.0121	23	81	8.19	2.5	0.034
93	'EDGEWATER4'	217	3	1	5	1	9	20	11	20	4	5.4	0	0	0	0	0	0	0	0.0124	19	91	19.53	18.86	0.118
25	'A.S.KING '	574	3	1	5	1	9	20	11	20	5	7	0	0	0	0	0	0	0	0.0125	0	15.17	8.255	0	0
28	'SHERBURNE3'	871	3	1	5	1	9	20	11	20	3	5	0	0	0	0	0	0	0	0.0125	0	2.53	3.991	0	0
94	'EDGEWATER5'	294	3	1	5	1	9	20	11	20	4	2.5	0	0	0	0	0	0	0	0.0129	21	65	6.71	3.76	0.011
78	'EDGEWATER5'	97	3	1	5	1	9	20	11	20	4	2	5	38	0	0	0	0	0	0.0136	0	0	0	0	0
96	'NLSNDEWEY2'	111	3	1	5	1	9	20	11	20	4	2.4	0	0	0	0	0	0	0	0.0136	21	23	7.54	9.19	0.126
95	'NLSNDEWEY1'	108	3	1	5	1	9	20	11	20	4	8.1	0	0	0	0	0	0	0	0.0137	21	50	7.54	8.47	0.127
107	'PULIAM8 '	135	3	1	5	1	9	20	11	20	2	5	0	25	0	0	0	0	0	0.0137	20	43	17.2	8.75	0.031
51	'OIL CTS '	111	3	1	5	1	9	20	11	20	0	15	0	0	0	0	0	0	0	0.0138	0	0.6	0.255	0	0.02
52	'GAS CTS '	186	3	1	5	1	9	20	11	20	0	40	0	0	0	0	0	0	0	0.0138	0	7.65	1.2	0	0.15
108	'PULIAM7 '	88	3	1	5	1	9	20	11	20	2	5	0	16	0	0	0	0	0	0.014	20	81	17.52	8.92	0.031
90	'COLUMBIA1 '	237	3	1	5	1	9	20	11	20	5	8	0	0	0	0	0	0	0	0.0141	22	07	13.89	4.97	0.011
97	'ROCKRIVER1'	73	3	1	5	1	9	20	11	20	4	1.6	0	0	0	0	0	0	0	0.0141	21	34	29.76	14.16	0.126
26	'SHERBURNE1'	712	3	1	5	1	9	20	11	20	2	3	0	0	0	0	0	0	0	0.0142	0	2.72	4.289	0	0.52
29	'RIVERSIDE8'	215	3	1	5	1	9	20	11	20	4	15	0	0	0	0	0	0	0	0.0142	0	4	9.79	0	0.8
27	'SHERBURNE2'	712	3	1	5	1	9	20	11	20	2	5	0	0	0	0	0	0	0	0.0143	0	2.72	4.289	0	0.52
55	'OAK CREEK8'	305	3	1	5	1	9	20	11	20	5	1	1.6	85	0	0	0	0	0	0.0143	18	68	7.6	2.56	0.016
56	'OAK CREEK7'	280	3	1	5	1	9	20	11	20	5	1	1.6	85	0	0	0	0	0	0.0143	18	68	7.6	2.56	0.016
98	'ROCKRIVER2'	74	3	1	5	1	9	20	11	20	4	5.7	0	0	0	0	0	0	0	0.0143	21	67	30.21	19.27	0.128
58	'OAK CREEK5'	258	3	1	5	1	9	20	11	20	5	2	2.9	82	0	0	0	0	0	0.0148	19	04	7.75	2.61	0.016
57	'OAK CREEK6'	260	3	1	5	1	9	20	11	20	5	2	3	82	0	0	0	0	0	0.0149	19	07	7.76	2.62	0.016
36	'HIGHBRDGE6'	169	3	1	5	1	9	20	11	20	2	18	0	0	0	0	0	0	0	0.0154	0	4.65	6.76	7	0.95
92	'EDGEWATER3'	70	3	1	5	1	9	20	11	20	4	3.1	0	0	0	0	0	0	0	0.0158	23	83	23.37	22.46	0.141
30	'RIVERSIDE7'	130	3	1	5	1	9	20	11	20	2	10	0	0	0	0	0	0	0	0.0161	0	4.6	11.262	0	0.92
35	'HIGHBRDGE5'	93	3	1	5	1	9	20	11	20	2	10	0	0	0	0	0	0	0	0.0162	0	4.94	7.183	0	1.01
74	'PRESQUEIS4'	57	3	1	5	1	9	20	11	20	1	1	2.4	12	0	0	0	0	0	0.0162	22	50	16.63	6.5	0.016
109	'PULIAM6 '	67	3	1	5	1	9	20	11	20	2	5	0	14	0	0	0	0	0	0.0162	23	87	11.06	12.6	0.036
72	'PRESQUEIS6'	85	3	1	5	1	9	20	11	20	1	1	2.2	20	0	0	0	0	0	0.0163	22	37	16.54	8.9	0.015
73	'PRESQUEIS5'	84	3	1	5	1	9	20	11	20	1	1	2.2	19	0	0	0	0	0	0.0163	22	38	16.55	8.91	0.015
34	'BLACKDOG4 '	176	3	1	5	1	9	20	11	20	2	20	0	0	0	0	0	0	0	0.0164	0	6.55	8.41	1	0.33
40	'WILMARTH1 '	11	3	1	5	1	9	20	11	20	4	10	0	0	0	0	0	0	0	0.0165	0	2.81	5.28	6	0.5
77	'PRESQUEIS1'	25	3	1	5	1	9	20	11	20	0	0	0	0	0	0	0	0	0	0.0165	33	81	19.23	13.46	0.024
32	'BLACKDOG2 '	100	3	1	5	1	9	20	11	20	2	35	0	0	0	0	0	0	0	0.0167	0	6.7	8.60	4	0.34
33	'BLACKDOG3 '	110	3	1	5	1	9	20	11	20	2	15	0	0	0	0	0	0	0	0.0167	0	6.72	8.62	2	0.34
76	'PRESQUEIS2'	37	3	1	5	1	9	20	11	20	0	0	0	0	0	0	0	0	0	0.0167	30	28	22.39	12.05	0.021
110	'PULIAM5 '	52	3	1	5	1	9	20	11	20	2	5	0	16	0	0	0	0	0	0.0167	24	32	11.27	12.84	0.036
75	'PRESQUEIS3'	58	3	1	5	1	9	20	11	20	1	1	2.4	12	0	0	0	0	0	0.017	22	50	16.63	6.5	0.016

```
31   'BLACKDOG1 '78  3 1 5 1 9 20  11 202 15  0   0 0 0 0 0   0 0   0.0176  0  7.18  9.218 0 0.36  0 0  0
41   'WILMARTH2 ' 11  3 1 5 1 9 20  11 204 10  0   0 0 0 0 0   0 0   0.0176  0  2.99  5.635 0 0.53  0 0  0
7    'GENOA3    ' 3763 1 5 1 9 20   11 204 12  0   0 0 0 0 0   0 0   0.01769   2183 14.98 8.56  0.03  1.61  0.011  0 0
37   'MINNVALLEY'48  3 1 5 1 9 20  11 202 15  0   0 0 0 0 0   0 0   0.0181  0  10.29 6.15  0 0.53  0 0  0
10   'COLUMBIA1 ' 1133 1 5 1 9 20  11 205 4.1 15.5 88  0 0   0 0   0   0 0.0183  2207 13.89 4.97  0.011 0.518 0.018 0 0
6    'JPM1      ' 3743 1 5 1 9 20  11 204 4 0 0   0   0 0 0 0 0   0.01883  1831  6.55  4.2 0.03  0.25  0.008 0 0
61   'PORT WASH2'  80  3 1 5 1 9 20 11 200 0   4   1.3 29  0   0 0   0   0 0 0.0199  2167  23.34 3.75  0.0156   0.417 0.166  0 0
24   'CCS(NEW)  '1203 1 5 1 9 20   11 202 5.5 0   0 0 0 0 0   0 0   0.0201  9990  0.24  0.11  0 0.064 0 0
62   'PORT WASH1'  80  3 1 5 1 9 20 11 200 0   4   1.3 29  0   0 0   0   0 0 0.0203  2237  24.09 3.87  0.0161   0.43  0.171  0 0
65   'VALLEY2   ' 62  3 1 5 1 9 20   11 208 2.5 3.9 30  0 0 0   0 0   0   0.0214  2436  26.58 5.86  0.0222  0.586 0.013 0 0
63   'VALLEY4   ' 70  3 1 5 1 9 20   11 200 2.5 4   34  0 0 0   0 0   0   0.0216  2436  26.58 5.86  0.0222  0.586 0.013 0 0
44   'BAYFRONT6 '30  3 1 5 1 9 20   11 204 7   0   0 0 0 0 0   0 0   0.0223  0  5.94  7.701 0 2.57  0 0  0
66   'VALLEY1   ' 64  3 1 5 1 9 20   11 208 1   13  7 0 0 0 0   0 0   0.0224  2557  27.91 6.15  0.0234  0.615 0.014  0 0
69   'PRESQUEIS9'84  3 1 5 1 9 20  11 201 1   3   14  0 0 0   0 0   0   0.0227  2392  12.54 8.05  0.0173  0.23  0.014 0 0
70   'PRESQUEIS8'83  3 1 5 1 9 20  11 201 1   3   14  0 0 0   0 0   0   0.0227  2392  12.53 8.05  0.0172  0.23  0.014 0 0
71   'PRESQUEIS7'81  3 1 5 1 9 20  11 201 1   3.2 13  0 0 0   0 0   0   0.0227  2392  12.53 8.05  0.0172  0.23  0.014 0 0
64   'VALLEY3   ' 70  3 1 5 1 9 20   11 200 1   15  14  0 0 0   0 0   0   0.023 2436 26.58 5.86  0.0222  0.586  0.013 0 0
43   'BAYFRONT5 '23  3 1 5 1 9 20  11 204 7   0   0 0 0 0 0   0 0   0.0232  0  6.25  8.105 0 2.7  0 0 0
46   'FRENCH IS2' 14  3 1 5 1 9 20  11 202 7   0   0 0 0 0 0   0 0   0.0233  0  1.43  6.537 0 1.28  0 0  0
45   'FRENCH IS1' 15  3 1 5 1 9 20  11 202 7   0   0 0 0 0 0   0 0   0.0236  0  1.46  6.642 0 1.3  0 0 0
60   'PORT WASH3'  82  3 1 5 1 9 20 11 200 0   4   1.4 29  0   0 0   0   0 0 0.0237  2155  32.2  3.73  0.0155   0.414 0.165  0 0
112  'PULIAM3   ' 26  3 1 5 1 9 20   11 202 18  0   14  0 0 0   0 0   0   0.0242  2543  11.78 13.43 0.038 0.25  0.013 0 0
42   'BAYFRONT4 '20  3 1 5 1 9 20  11 204 7   0   0 0 0 0 0   0 0   0.0248  0  6.78  8.793 0 2.93  0 0  0
1    'ALMA1     '20  3 1 5 1 9 20  11 201 7.69  0   0 0 0 0 0   0 0   0.02493   2797 26.64 12.65 0.04  0.13  0.01   0 0
2    'ALMA2     '22  3 1 5 1 9 20  11 201 7.69  0   0 0 0 0 0   0 0   0.02493   2797 26.64 12.65 0.04  0.13  0.01   0 0
3    'ALMA3     '21  3 1 5 1 9 20  11 201 7.69  0   0 0 0 0 0   0 0   0.02493   2797 26.64 12.65 0.04  0.13  0.01   0 0
4    'ALMA4     '59  3 1 5 1 9 20  11 202 4.6 0   0   0 0 0 0 0   0 0.02493   2333 22.22 10.55 0.03  0.11  0.011  0   0
5    'ALMA5     '85  3 1 5 1 9 20  11 202 3.1 0   0   0 0 0 0 0   0 0.02493   2209 21.04 9.99  0.03  0.21  0.011  0   0
111  'PULIAM4   ' 27  3 1 5 1 9 20   11 202 18  0   15  0 0 0   0 0   0   0.0253  2672  12.38 14.11 0.04  0.93   0.013 0 0
59   'PORT WASH4'  80  3 1 5 1 9 20 11 200 0   4   1.5 29  0   0 0   0   0 0 0.0267  2492  26.84 4.31  0.018 0.479  0.191   0 0
16   'BLOUNT6T8B'50  3 1 5 1 9 20  11 203 7.5 0   0 0 0 0 0   0 0   0.0283  2575  15  10  0.13  0.38  0 0 0
17   'BLOUNT7T9B'49  3 1 5 1 9 20  11 203 2.3 0   0 0 0 0 0   0 0   0.0283  2575  15  10  0.13  0.38  0 0 0
23   'CTS(NEW)  '40  3 1 5 1 9 20   11 201 3.5 0   0 0 0 0 0   0 0   0.0292  1525  0 1.098 0.17  0  0.122 0 0
18   'FITCHBURG1'21  3 1 5 1 9 20  11 201 15  0   0 0 0 0 0   0 0   0.0309  1584  0 5.459 0.13  13  0 0 0
19   'FITCHBURG2'21  3 1 5 1 9 20  11 201 15  0   0 0 0 0 0   0 0   0.0309  1588  0 5.472 0.13  0.13  0 0 0
22   'NINESPRNGS' 14  3 1 5 1 9 20  11 201 15  0 0 0 0 0   0 0   0   0.0313  1581  0 5.446 0.13  0.13  0 0   0
21   'SYCAMORE2 ' 20  3 1 5 1 9 20  11 201 15  0 0 0 0 0   0 0   0   0.0328  1699  0 5.855 0.14  0.14  0 0   0
20   'SYCAMORE1 ' 14  3 1 5 1 9 20  11 201 15  0 0 0 0 0   0 0   0   0.0346  1809  0 6.232 0.15  0.15  0 0   0
123  'WMARINTT33'75  3 1 5 1 9 20  11 202 4.3 0   19  0 0 0   0 0   0   0.0355  0  0 0 0 0 0 0
14   'BLOUNT5&6B'38  3 1 5 1 9 20  11 202 3   0   0 0 0 0 0   0 0   0.0371  1955  0 4.6 0.16  0 0 0 0
15   'BLOUNT7B  ' 23  3 1 5 1 9 20  11 202 3   0   0 0 0 0 0   0 0   0.0371  3386  57.53 13.15 0.16  0.49  0 0   0
13   'BLOUNT3&11'27  3 1 5 1 9 20  11 202 3   0   0 0 0 0 0   0 0   0.0374  1969  0 4.634 0.17  0  0 0 0
104  'BLACKHAWK4' 28  3 1 5 1 9 20  11 200 0   4.3 0 0 0 0 0   0 0   0   0.039 1362 0.12  17.93 0.047 0 0.003  0   0
103  'BLACKHAWK3' 27  3 1 5 1 9 20  11 200 0   4.3 0 0 0 0 0   0 0   0   0.0404  1418  0.12  16.73 0.048 0 0.004  0   0
12   'BLOUNT1&2B'6  3 1 5 1 9 20   11 201 20  0   0 0 0 0 0   0 0   0.0417  2261  0 5.32  0.19  0  0 0 0
120  'WESTON32  ' 50  3 1 5 1 9 20  11 201 5   0   14  0 0 0   0 0   0   0.0417  2658  10.42 15.36 0.039 0.26   0.026 0 0
122  'WMARINTT32'40  3 1 5 1 9 20  11 201 5   0   9 0 0 0 0   0 0   0.0425  0  0 0 0 0 0 0
121  'WMARINTT31'40  3 1 5 1 9 20  11 201 5   0   11  0 0 0   0 0   0   0.0427  0  0 0 0 0 0 0
101  'ROCKRIVER5'46  3 1 5 1 9 20  11 200 4.3 0   0 0 0 0 0   0 0   0.0433  1452  0.12  51.25 0.05  0  0.004 0   0
102  'ROCKRIVER6'44  3 1 5 1 9 20  11 200 4.3 0   0 0 0 0 0   0 0   0.0436  1463  0.13  51.63 0.05  0  0.004 0   0
79   'CONCORD4  '83  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.047 1609 0 1.16  0.1803  0  0.004 0 0
80   'CONCORD3  '83  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.047 1609 0 1.16  0.1803  0  0.004 0 0
81   'CONCORD2  '83  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.047 1609 0 1.16  0.1803  0  0.004 0 0
82   'CONCORD1  '83  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.047 1609 0 1.16  0.1803  0  0.004 0 0
47   'PATHFINDER'64  3 1 5 1 9 20  11 202 20  0   0 0 0 0 0   0 0   0.0481  0  0 5.118 0 0.12  0 0  0
119  'WESTON31  ' 20  3 1 5 1 9 20  11 202 5   0   5 0 0 0 0   0 0   0.0483  3276  12.84 18.94 0.048 0.32  0.032 0   0
100  'ROCKRIVER4'13  3 1 5 1 9 20  11 200 4.3 0   0 0 0 0 0   0 0   0.0511  1837  0.16  64.83 0.063 0  0.005 0   0
124  'EAGLERIVR1'4  3 1 5 1 9 20   11 200 5   0   0 0 0 0 0   0 0   0.0552  0  0 0 0 0 0 0
87   'OAK CREEK9'20  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.0557  3296  41.6  13.6  0.16  0.8 0 0 0
99   'ROCKRIVER3'25  3 1 5 1 9 20  11 200 4.3 0   0 0 0 0 0   0 0   0.0581  2069  0.18  73.03 0.071 0  0.005 0   0
83   'GERMNTOWN4'53  3 1 5 1 9 20  11 200 1   0 0 0 0 0   0 0   0   0.06  3296 41.6  13.6  0.16  0.8 0 0   0
84   'GERMNTOWN3'53  3 1 5 1 9 20  11 200 1   0 0 0 0 0   0 0   0   0.06  3296 41.6  13.6  0.16  0.8 0 0   0
85   'GERMNTOWN2'53  3 1 5 1 9 20  11 200 1   0 0 0 0 0   0 0   0   0.06  3296 41.6  13.6  0.16  0.8 0 0   0
86   'GERMNTOWN1'53  3 1 5 1 9 20  11 200 1   0 0 0 0 0   0 0   0   0.06  3296 41.6  13.6  0.16  0.8 0 0   0
88   'PNT BEACH5'20  3 1 5 1 9 20  11 200 1   0   0 0 0 0 0   0 0   0.0637  3296  41.6  13.6  0.16  0.8 0 0 0
89   'PORT WASH6'  18  3 1 5 1 9 20 11 200 0   1   0 0 0 0 0   0 0   0   0.0651  3296  41.6  13.6  0.16  0.8 0   0   0
```

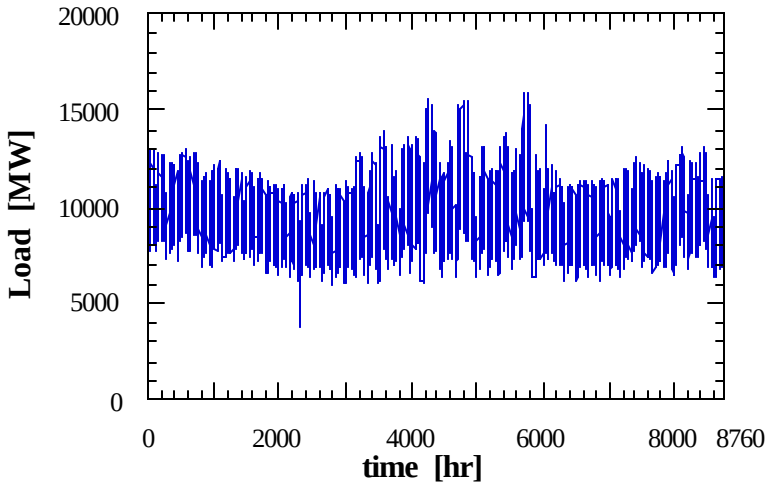

Figure B-7: Regional 1991 Load

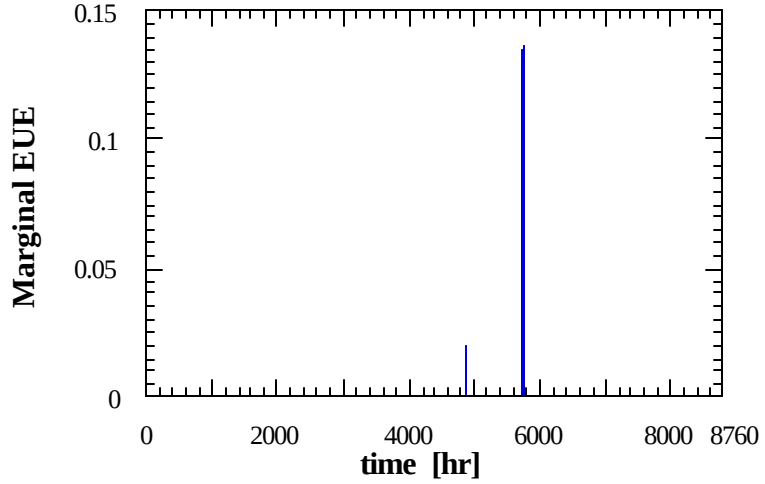

Figure B-8: Regional 1991 Marginal EUE

APPENDIX B

TRNSYS Simulations

EDHW System

One Tank SDHW System

Two Tank SDHW System

One Tank SDHW System with SRCC Collector

Two Tank SDHW System with SRCC Collector

Photovoltaic System

Marginal Plant Prediction

Utility Impact Analysis

Quick Economic Analysis

EDHW System

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ EDHW.LST     6
ASSIGN C:\ EUSESIA\ SYSTEMS\ EDHW.OUT     10
ASSIGN C:\ EUSESIA\ SYSTEMS\ EDHW.PLT     17
ASSIGN C:\ EUSESIA\ SYSTEMS\ HRDRAW.DAT   15


*******************************************************************
*
*     This file predicts the required electric input to an electric
*  domestic hot water system.
*
*******************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|1|2|99
ASSIGN c:\ EUSESIA\ systems\ MLKMAIN.DAT 16
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|4|99
*|*

***  SYSTEM PARAMETERS  ***
EQUATIONS  6
TSET = 60
TENV = 18
TI = 6.9
*
*  Determine the required draw from the tank.  The following equations
*  account for the tempering valve.  They result from a simplified mass
*  and energy balance where Cp is assumed constant.
TDIFF = MAX(0.000001,([4,3]-[39,1]))
TNKDRW = MIN(1,((TSET-[39,1])/TDIFF))
MLOAD = [29,1]*TNKDRW


***  ELECTRIC HOT WATER TANK   ***
* Volume:  80 gallon tank -> .3028 m3;
* Height:  4.89 ft -> 1.4905 m
* R-value: 16.7 (hr-ft2-F/Btu) -> 2.6469 (hr-m2-C/kJ);  ULOSS=1/R
*              .1585(hr-m2-C/kJ)/(hr-ft2-F/Btu)

*|* Tank Parameters
EQUATIONS 7
TNKSIZE =  8.0000E+0001
*| Tank size                                |gal|gal|0|1|0|1000.00|3
TSIZE = .0037854*TNKSIZE
HEIGHT1 =  4.8900E+0000
*| Tank height                              |ft|ft|0|1|0|0030.00|3
```

```
HEIGHT = .3048*HEIGHT1
RVAL =  1.6700E+0001
*| Insulation R-Value                          |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVAL1 = RVAL *.0489194
ULOSS = 1/RVAL1
*|*

** More Tank Parameters
EQUATIONS 4
HGT = -HEIGHT
NODES = 3
Tdbnd = 0.0
Qmax = 4.5*3600

*|* Daily Water Draw
EQUATIONS 3
FACTOR = 3.7853
MLTPLY =  6.9000E+0001
*| Average daily water draw (69 gal/day standard)
|gal/day|gal/day|0|1|0|100.0|3
SCALE = FACTOR*MLTPLY/69
* Standard draw based on approximately 69 gal/day.  MLTPLY allows the
*  user to scale the draw as seen fit.  By setting the value to 69 the
*  draw remains the same.
*|*

***  SIMULATION PARAMETERS  ***
EQUATIONS 4
START = 1
START1 = START-48
STOP = 8760
step = .1

** Calculate the critical timestep for the system.
** Use STEP < t_critical as a safety factor
** Calculation done assuming an instantaneous draw will
**  be no more than 10 gal/hr
*EQUATIONS 5
*MASSTANK = TNKSIZE*FACTOR
*MLOADMAX = 10*FACTOR
*TCRIT = (MASSTANK/NODES)/MLOADMAX
*STEP1 = TCRIT/2
*STEP = MIN(STEP1,1)

SIMULATION START1 STOP STEP
LIMITS  120 120 120
TOLERANCES  0.001 0.001
WIDTH = 120



UNIT 29 TYPE 9   DATA READER FOR WATER DRAWS
PARAMETERS 7
*  MODE  N  DT  DRAW  MULT   ADD  LU  FRMT
```

```
   2     1  1   -1    SCALE   0   15   0
* OUTPUTS:  1,DRAW  (kg/hr)


UNIT 39 TYPE 9  DATA READER FOR MAINS TEMPERATURES
PARAMETERS 8
*  MODE  N  dT(HRS)  TMAINS  LU  FRMT
    2    1   24      -1 1 0  16   0
* OUTPUTS:  1,TMAINS


UNIT 4 TYPE 4  SOLAR STORAGE TANK
PARAMETERS 20
*MODE   VOL   CPF    RHO    UT    HI     AUXMOD    NODE1   NODETI
  1    TSIZE  4.19  1000   ULOSS  HGT      1         1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET   Tdbnd  QMAX        1       1      TSET     0      QMAX
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH   TL    ML     TENV
 0,0   0,0  39,1  MLOAD  0,0
 0.0   0.0  TI    0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*UNIT 4 OUTPUTS:
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 24 TYPE 24  INTEGRATOR
PARAMETERS 1
*DT RESET
   1
INPUTS 1
4,8
0.0

EQUATIONS 1
* Electric input required (auxiliary heater + collector pump power)
QAUX = ([24,1])/3600


*|* Display Options
EQUATIONS 2
IREF = 1/STEP
SWITCH = 1
*| On-line graphic display (1=yes, 2=no)      |||0|1|1|2|3

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
*NTOP  NBOT  YMIN1  YMAX1  YMIN2  YMAX2  IREF  IUP  UNITS
 1      0     0       5       0      200   IREF   1     3
*NPIC  GRID  STOP  SYMBOLS  OUTPUT  ON/OFF
  1     7     0       2       0     SWITCH
```

```
INPUTS 1
 QAUX
 Qaux
LABELS 4
 kWh  kWh
 Average System Demand
 None

UNIT 25 TYPE 25  PRINTER
PARAMETERS 4
*  DT  TON    TOFF  LU
   1   START  STOP  10
INPUTS 1
  QAUX
  ELCDMD


UNIT 26 TYPE 25  plotter
PARAMETERS 4
*  DT  TON    TOFF  LU
   1   START  STOP  17
INPUTS 1
  QAUX
  ELCDMD

END
```

One Tank SDHW System

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW1TNK.LST       6
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW1TNK.OUT      10
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW1TNK.PLT      22
ASSIGN C:\ EUSESIA\ SYSTEMS\ HRDRAW.DAT        15



*************************************************************
*  This file predicts the required electric input to a solar *
* domestic hot water system                                  *
*************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|1|2|99
EQUATIONS 1
LAT =  4.2950E+0001
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|3|99
ASSIGN c:\ EUSESIA\ systems\ MLKMAIN.DAT 16
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|4|99
*|*

***  SYSTEM PARAMETERS  ***
EQUATIONS  6
TSET = 60
TENV = 18
TI = 6.9
*
*  Determine the required draw from the tank.  The following equations
*  account for the tempering valve.  They result from simplified mass
*  and energy balances where Cp is assumed constant.
TDIFF = MAX(0.000001,([4,3]-[39,1]))
TNKDRW = MIN(1,((TSET-[39,1])/TDIFF))
MLOAD = [29,1]*TNKDRW
*
***   STANDARD ELECTRIC HOT WATER TANK   ***
* Volume:  80 gallon tank -> .3028 m3;
* Height:  4.89 ft -> 1.4905 m
* R-value: 16.7 (hr-ft2-F/Btu) -> ULOSS=1/R
*              .0489194(hr-m2-C/kJ)/(hr-ft2-F/Btu)

*|* Tank Parameters
EQUATIONS 7
TNKSIZE =  8.0000E+0001
*| Tank size                                 |gal|gal|0|1|0|1000.00|3
TSIZE = .0037854*TNKSIZE
HEIGHT1 =  4.8900E+0000
```

```
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHT = .3048*HEIGHT1
RVAL =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVAL1 = RVAL *.0489194
ULOSS = 1/RVAL1
*|*

EQUATIONS 3
NODES = 3
Tdbnd = 0.0
Qmax = 4.5*3600

*|* Solar Collector Parameters
EQUATIONS 7
COL =  1.0000E+0000
*| Number of collectors in array              |||0|1|1|000100|3
AREA1 =  6.0000E+0001
*| Area of a single collector                 |ft2|ft2|0|1|0|100.00|3
AREA = COL*AREA1*.0929
FRta =  7.0000E-0001
*| FRta of collector (Intercept efficiency)   |||0|1|0|001.00|3
FRUL1 =  7.4900E-0001
*| FRUL of collector (- slope of eff. curve)  |Btu/hr-ft2-F|Btu/hr-ft2-
F|0|1|0|10.000|3
FRUL = 20.4418*FRUL1
SLOPE =  2.3000E+0001
*| Collector slope                            |degrees|degrees|0|1|0|0090.0|3
*|*

*|* Heat Exchanger Parameters
EQUATIONS 3
EFF = -1.0000E+0000
*| Heat exchanger effectiveness (-1 => no hx) |||0|1|-1|01.000|3
CPH1 =  5.7700E-0001
*| Specific heat of collector side fluid      |Btu/lbm-R|Btu/lbm-
R|0|1|0|10.000|3
CPHOT = 4.1868*CPH1
*|*

*|* Pump Parameters
EQUATIONS 2
PMPPOW = 50
*| Pumping power                              |W|W|0|1|0|10000.0|3
PPUMP = PMPPOW*3.6
*|*

*|* Daily Water Draw
EQUATIONS 3
FACTOR = 3.7853
MLTPLY =  6.9000E+0001
*| Average daily water draw (69 gal/day standard)
|gal/day|gal/day|0|1|0|100.0|3
SCALE = FACTOR*MLTPLY/69
```

```
* Standard draw based on approximately 69 gal/day.  MLTPLY allows the
*  user to scale the draw as seen fit.  By setting the value to 69 the
*  draw remains the same.
*|*

*** SIMULATION PARAMETERS ***
EQUATIONS 4
START = 1
START1 = START-48
STOP = 8760
step = .1

EQUATIONS 5
RHOG=2.0000E-01
STRTDAY = INT(START1/24)
GAMMAI=0.0000E+0
SC=4871
SHIFT=0.0

** Calculate the critical timestep for the system.
** Use STEP < t_critical as a safety factor
** Calculation done assuming an instantaneous draw will
**  be no more than 10 gal/hr
*EQUATIONS 6
*MASSTANK = TNKSIZE*FACTOR
*MCOLL = 325
*MLOADMAX = 10*FACTOR
*TCRIT = (MASSTANK/NODES)/(MCOLL+MLOADMAX)
*STEP1 = TCRIT/2
*STEP = MIN(STEP1,1)



SIMULATION START1 STOP STEP
LIMITS 120 120 120
TOLERANCES 0.001 0.001
WIDTH 72

UNIT 19 TYPE 9   DATA READER FOR WEATHER
PARAMETERS 14
* MODE  N  dT(HOURS)   DUMHOURS    Tdb(C)  I(kJ/m2-hr)
  -2    3     1          -1 1 0    -2 1 0  -3 1 0
*      LU FRMT
       14   0
*OUTPUTS: 2,Tdb 3,I



UNIT 29 TYPE 9 DATA READER FOR WATER DRAWS
*WATER DRAWS:  (GAL/HR) - CONVERT TO KG/HR
* USE FACTOR 3.7853, FURTHER SCALING DONE WITH MLTPLY/69
PARAMETERS 8
* MODE  N   STEP  DRAWS   MULT   ADD   LU   FRMT
  -2    1     1   -1      SCALE   0.    15    0
*OUTPUTS: 1,DRAW(KG/HR)
```

```
UNIT 39 TYPE 9  DATA READER FOR MAINS WATER TEMPERATURE
* CHANGES MONTHLY BUT READ IN DAILY (24 HOURS) FROM F-CHART FILE
PARAMTERS 8
* MODE   N  dT(HOURS) TMAINS   LU  FRMT
   -2    1     24     -1 1 0   16   0
*OUTPUTS: 1, TMAINS

UNIT 16 TYPE 16 RADIATION PROCESSOR
PARAMETERS 8
* RADMODE TRACKMODE TILTMODE  DAY      LAT  SC  SHIFT  SMOOTH
    3         1        1     STRTDAY   LAT  SC  SHIFT    2
INPUTS 6
* I(kJ/m2-hr)  td1    td2    RHOG    BETA1    GAMMAI  INext(IF SMOOTH=1)
 19,3          19,19  19,20  RHOG    SLOPE    GAMMAI  19,23
 0.0           0.0    0.0    RHOG    SLOPE    GAMMAI  0.0
*OUTPUTS: 1,Io 2,THETAz 3,GAMMAs 4,I 5,Id 6,IT1 7,IbT1 8,IdT1 9,THETA1
*         10,BETA1 11,IT1


UNIT 1 TYPE 1 COLLECTOR
PARAMETERS 14
* MODE N  AREA  Cp   EFFMD  G   ao    a1    a2  EFF CpHX  OPTMD  bo  b1
   1   1  AREA  4.19   1    50  FRta  FRUL  0.  EFF CPHOT   1    0.1 0.0
INPUTS 10
* Ti  mCOLL(kg/hr) mHX  Tamb   It    I    Id    RHOG  THETA BETA(SLOPE)
 3,1  3,2          3,2  19,2  16,6 16,4  16,5   0,0    16,9   16,10
 TI   0.0          0.0  20.0   0.0  0.0   0.0   RHOG    0.0    40.0
*OUPUTS: 1, To 2,mo 3,Qgain(KJ/HR) 4,Tco


EQUATIONS 2
DEADH = 0
DEADL = 0

UNIT 2 TYPE 2 PUMP CONTROLLER
PARAMETERS 4
* NSTK dThigh dTlow  Tmax
   11  DEADH  DEADL   100
INPUTS 4
* Th   Tl    TIN  GAMMAI
  1,4  4,1   0,0   2,1
  15.  TI    100    0.
*OUTPUTS: 1,GAMMAo (CONTROL FUNCTION)

UNIT 3 TYPE 3 PUMP
PARAMETERS 4
* mMAX    Cp    Pmax(KJ/HR)   fpar
  325.    4.19    PPUMP        0.
INPUTS 3
*  Ti    mi   GAMMA
  4,1    4,2   2,1
   TI    0.0    0.0
*OUTPUTS: 1,To 2,mo 3,Ppump
```

```
EQUATIONS 1
HGT = -HEIGHT

UNIT 4 TYPE 4  SOLAR STORAGE TANK
PARAMETERS 20
*MODE   VOL   CPF    RHO    UT    HI     AUXMOD    NODE1   NODETI
  2    TSIZE  4.19  1000  ULOSS  HGT      1        1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0     QMAX        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH   TL    ML     TENV
 1,1   1,2  39,1  MLOAD  0,0
 0.0   0.0  TI    0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*UNIT 4 OUTPUTS:
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 24 TYPE 24  INTEGRATOR
PARAMETERS 1
*DT RESET
   1
INPUTS 2
4,8  3,3
0.0  0.0

EQUATIONS 2
* Electric input required (auxiliary heater + collector pump power)
ELECDMND = ([24,1]+[24,2])/3600
QAUX = ([24,1])/3600


UNIT 25 TYPE 25  PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP 10
INPUTS 1
elecdmnd
elcdmd


UNIT 26 TYPE 25  plotting PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP  22
INPUTS 1
elecdmnd
elcdmd

*|* Display Options
```

```
EQUATIONS 2
IREF = 1/(STEP+.00001)
SWITCH =  1.0000E+0000
*| On-line graphic display (1=yes, 2=no)      |||0|1|1|2|3

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
*NTOP  NBOT  YMIN1  YMAX1  YMIN2  YMAX2  IREF  IUP  UNITS
 2     1     0       5     0        80   IREF     1     3
*NPIC  GRID  STOP  SYMBOLS  OUTPUT  ON/OFF
  1     7     0       2       0     SWITCH
INPUTS 3
 QAUX  ELECDMND  MLOAD
 Qaux  ElecDmnd  MTANK
LABELS 4
 kW  kg/hr
 Average System Demand
 Tank Draw

END
```

Two Tank SDHW System

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW2TNK.LST       6
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW2TNK.OUT      10
ASSIGN C:\ EUSESIA\ SYSTEMS\ SDHW2TNK.PLT      22
ASSIGN C:\ EUSESIA\ SYSTEMS\ HRDRAW.DAT        15


*****************************************************************
*  This file predicts the required electric input to a two tank *
*   solar domestic hot water system                              *
*****************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|1|2|99
EQUATIONS 1
LAT =  4.2950E+0001
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|3|99
ASSIGN c:\ EUSESIA\ systems\ MLKMAIN.DAT 16
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|4|99
*|*


***  SYSTEM PARAMETERS  ***
EQUATIONS  6
TSET = 60
TENV = 18
TI = 6.9
*
*  Determine the required draw from the tank.  The following equations
*  account for the tempering valve.  They result from simplified mass
*  and energy balances where Cp is assumed constant.
TDIFF = MAX(0.000001,([4,3]-[39,1]))
TNKDRW = MIN(1,((TSET-[39,1])/TDIFF))
MLOAD = [29,1]*TNKDRW
*
***   STANDARD ELECTRIC HOT WATER TANK   ***
* Volume:  80 gallon tank -> .3028 m3;
* Height:  4.89 ft -> 1.4905 m
* R-value: 16.7 (hr-ft2-F/Btu) -> ULOSS=1/R
*              .0489194(hr-m2-C/kJ)/(hr-ft2-F/Btu)

*|* Solar Storage Tank Parameters
EQUATIONS 7
TNKSIZES =  8.0000E+0001
*| Tank size                                |gal|gal|0|1|0|1000.00|3
TSIZES = .0037854*TNKSIZES
HEIGHT1S =  4.8900E+0000
```

```
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHTS = .3048*HEIGHT1S
RVALS =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVALS1 = RVALS *.0489194
ULOSSS = 1/RVALS1
*|*

*|* Auxiliary Tank Parameters
EQUATIONS 7
TNKSIZEA =  8.0000E+0001
*| Tank size                                  |gal|gal|0|1|0|1000.00|3
TSIZEA = .0037854*TNKSIZEA
HEIGHT1A =  4.8900E+0000
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHTA = .3048*HEIGHT1A
RVALA =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVALA1 = RVALA *.0489194
ULOSSA = 1/RVALA1
*|*

** Other tank parameters.  S -> solar, A -> auxiliary
EQUATIONS 4
NODES = 3
NODEA = 3
Tdbnd = 0.0
Qmax = 4.5*3600

*|* Solar Collector Parameters
EQUATIONS 7
COL =  1.0000E+0000
*| Number of collectors in array              |||0|1|0|000100|3
AREA1 =  6.0000E+0001
*| Area of a single collector                 |ft2|ft2|0|1|0|100.00|3
AREA = AREA1*.0929
FRta =  7.0000E-0001
*| FRta of collector (Intercept efficiency)   |||0|1|0|001.00|3
FRUL1 =  7.4900E-0001
*| FRUL of collector (- slope of eff. curve)  |Btu/hr-ft2-F|Btu/hr-ft2-
F|0|1|0|10.000|3
FRUL = 20.4418*FRUL1
SLOPE=  2.3000E+0001
*| Collector slope                            |degrees|degrees|0|1|0|0090.0|3
*|*

*|* Heat Exchanger Parameters
EQUATIONS 3
EFF = -1.0000E+0000
*| Heat exchanger effectiveness (-1 => no hx) |||0|1|-1|01.000|3
CPH1 =  5.7700E-0001
*| Specific heat of collector side fluid      |Btu/lbm-R|Btu/lbm-
R|0|1|0|10.000|3
```

```
CPHOT = 4.1868*CPH1
*|*

*|* Pump Parameters
EQUATIONS 2
PMPPOW = 50
*| Pumping power                                |W|W|0|1|0|10000.0|3
PPUMP = PMPPOW*3.6
*|*

*|* Daily Water Draw
EQUATIONS 3
FACTOR = 3.7853
MLTPLY =  6.9000E+0001
*| Average daily water draw (69 gal/day standard)
|gal/day|gal/day|0|1|0|100.0|3
*|*
SCALE = FACTOR*MLTPLY/69
* Standard draw based on approximately 69 gal/day.  MLTPLY allows the
*  user to scale the draw as seen fit.  By setting the value to 69 the
*  draw remains the same.


*** SIMULATION PARAMETERS ***
EQUATIONS 4
START = 1
START1 = START-48
STOP = 8760
STEP = .1

EQUATIONS 5
RHOG=2.0000E-01
STRTDAY = INT(START1/24)
GAMMAI=0.0000E+0
SC=4871
SHIFT=0.0

** Calculate the critical timestep for the system.
** Use STEP < t_critical as a safety factor
** Calculation done assuming an instantaneous draw will
**  be no more than 10 gal/hr
*EQUATIONS 10
*MASSTANKS = TNKSIZES*FACTOR
*MCOLL = 325
*MLOADMAX = 10*FACTOR
*TCRITS = (MASSTANKS/NODES)/(MCOLL+MLOADMAX)
*STEPS = TCRITS/2
*
*MASSTANKA = TNKSIZEA*FACTOR
*TCRITA = (MASSTANKA/NODEA)/MLOADMAX
*STEPA = TCRITA/2
*
*STEP1 = MIN(STEPS,STEPA)
*STEP = MIN(STEP1,1)
```

```
SIMULATION START1 STOP STEP
LIMITS 120 120 120
TOLERANCES 0.001 0.001
WIDTH 72

UNIT 19 TYPE 9   DATA READER FOR WEATHER
PARAMETERS 14
* MODE  N  dT(HOURS)   DUMHOURS    Tdb(C)  I(kJ/m2-hr)
  -2    3     1          -1 1 0    -2 1 0  -3 1 0
*      LU FRMT
       14   0
*OUTPUTS: 2,Tdb 3,I


UNIT 29 TYPE 9 DATA READER FOR WATER DRAWS
*WATER DRAWS:  (GAL/HR) - CONVERT TO KG/HR
* USE FACTOR 3.7853
PARAMETERS 8
* MODE  N   STEP  DRAWS   MULT   ADD   LU   FRMT
  -2    1     1   -1     SCALE   0.    15    0
*OUTPUTS: 1,DRAW(KG/HR)


UNIT 39 TYPE 9  DATA READER FOR MAINS WATER TEMPERATURE
* CHANGES MONTHLY BUT READ IN DAILY (24 HOURS) FROM F-CHART FILE
PARAMTERS 8
* MODE   N  dT(HOURS) TMAINS   LU  FRMT
   -2    1     24     -1 1 0   16   0
*OUTPUTS: 1, TMAINS

UNIT 16 TYPE 16 RADIATION PROCESSOR
PARAMETERS 8
* RADMODE TRACKMODE TILTMODE  DAY      LAT  SC  SHIFT  SMOOTH
    3         1        1     STRTDAY   LAT  SC  SHIFT    2
INPUTS 6
* I(kJ/m2-hr)  td1    td2    RHOG    BETA1    GAMMAI  INext(IF SMOOTH=1)
 19,3          19,19  19,20  RHOG    SLOPE    GAMMAI  19,23
 0.0           0.0    0.0    RHOG    SLOPE    GAMMAI  0.0
*OUTPUTS: 1,Io 2,THETAz 3,GAMMAs 4,I 5,Id 6,IT1 7,IbT1 8,IdT1 9,THETA1
*         10,BETA1 11,IT1


UNIT 1 TYPE 1 COLLECTOR
PARAMETERS 14
* MODE N  AREA  Cp   EFFMD  G   ao    a1    a2  EFF CpHX  OPTMD  bo  b1
   1   1  AREA  4.19   1    50  FRta  FRUL  0.  EFF CPHOT   1    0.1 0.0
INPUTS 10
* Ti  mCOLL(kg/hr) mHX  Tamb   It    I    Id    RHOG  THETA BETA(SLOPE)
 3,1  3,2          3,2  19,2  16,6 16,4  16,5   0,0    16,9   16,10
 TI   0.0          0.0  20.0   0.0  0.0   0.0   RHOG    0.0    40.0
*OUPUTS: 1, To 2,mo 3,Qgain(KJ/HR) 4,Tco


EQUATIONS 2
DEADH = 0
```

```
DEADL = 0

UNIT 2 TYPE 2 PUMP CONTROLLER
PARAMETERS 4
* NSTK dThigh dTlow  Tmax
   11  DEADH  DEADL   100
INPUTS 4
* Th   Tl    TIN  GAMMAI
  1,4  5,1   0,0   2,1
  15.  TI    100    0.
*OUTPUTS: 1,GAMMAo (CONTROL FUNCTION)

UNIT 3 TYPE 3 PUMP
PARAMETERS 4
* mMAX    Cp    Pmax(KJ/HR)   fpar
  325.    4.19    PPUMP        0.
INPUTS 3
*  Ti    mi   GAMMA
  5,1    5,2   2,1
   TI    0.0    0.0
*OUTPUTS: 1,To 2,mo 3,Ppump

EQUATIONS 2
HGTA = -HEIGHTA
HGTS = -HEIGHTS

UNIT 5 TYPE 4   SOLAR STORAGE TANK
PARAMETERS 20
*MODE   VOL    CPF    RHO    UT     HI    AUXMOD  NODE1   NODETI
  2    TSIZES  4.19  1000  ULOSSS  HGTS     1       1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0      0.0        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH    TL    ML     TENV
 1,1   1,2  39,1  MLOAD   0,0
 0.0   0.0   TI    0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 4 TYPE 4   AUXILIARY TANK
PARAMETERS 20
*MODE   VOL    CPF    RHO    UT     HI    AUXMOD  NODE1   NODETI
  2    TSIZEA  4.19  1000  ULOSSA  HGTA     1       1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0     QMAX        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH    TL    ML    TENV
  0,0  0,0   5,3   5,4   0,0
```

```
  0.0   0.0  TI    0.0   TENV
DERIVATIVES NODEA
TSET TSET TSET TSET TSET TSET TSET
*UNIT 4 OUTPUTS:
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 24 TYPE 24  INTEGRATOR
PARAMETERS 1
*DT RESET
   1
INPUTS 2
4,8  3,3
0.0  0.0

EQUATIONS 2
* Electric input required (auxiliary heater + collector pump power)
ELECDMND = ([24,1]+[24,2])/3600
QAUX = ([24,1])/3600


UNIT 25 TYPE 25  PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP 10
INPUTS 1
elecdmnd
elcdmd

UNIT 26 TYPE 25  plotting PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP  22
INPUTS 1
elecdmnd
elcdmd

*|* Display Options
EQUATIONS 2
IREF = 1/STEP
SWITCH =  1.0000E+0000
*| On-line graphic display (1=yes, 2=no)      |||0|1|1|2|3

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
*NTOP  NBOT  YMIN1  YMAX1  YMIN2  YMAX2  IREF  IUP  UNITS
 2     1     0       5     0        80   IREF     1     3
*NPIC  GRID  STOP  SYMBOLS  OUTPUT  ON/OFF
  1     7     0       2       0     SWITCH
INPUTS 3
 QAUX  ELECDMND  MLOAD
 Qaux  ElecDmnd  MTANK
LABELS 4
 kW  kg/hr
```

```
 Average System Demand
 Tank Draw

END
```

One Tank System with SRCC Collector

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC1TNK.LST       6
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC1TNK.OUT      10
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC1TNK.PLT      22
ASSIGN C:\ EUSESIA\ SYSTEMS\ HRDRAW.DAT        15



*************************************************************
*  This file predicts the required electric input to a solar *
* domestic hot water system                                  *
*************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|1|2|99
EQUATIONS 1
LAT =  4.2950E+0001
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|3|99
ASSIGN c:\ EUSESIA\ systems\ MLKMAIN.DAT 16
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|4|99
*|*


***  SYSTEM PARAMETERS  ***
EQUATIONS  6
TSET = 60
TENV = 18
TI = 6.9
*
*  Determine the required draw from the tank.  The following equations
*  account for the tempering valve.  They result from simplified mass
*  and energy balances where Cp is assumed constant.
TDIFF = MAX(0.000001,([4,3]-[39,1]))
TNKDRW = MIN(1,((TSET-[39,1])/TDIFF))
MLOAD = [29,1]*TNKDRW
*
***   STANDARD ELECTRIC HOT WATER TANK   ***
* Volume:  80 gallon tank -> .3028 m3;
* Height:  4.89 ft -> 1.4905 m
* R-value: 16.7 (hr-ft2-F/Btu) -> ULOSS=1/R
*              .0489194(hr-m2-C/kJ)/(hr-ft2-F/Btu)

*|* Tank Parameters
EQUATIONS 7
TNKSIZE =  8.0000E+0001
*| Tank size                                 |gal|gal|0|1|0|1000.00|3
TSIZE = .0037854*TNKSIZE
HEIGHT1 =  4.8900E+0000
```

```
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHT = .3048*HEIGHT1
RVAL =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVAL1 = RVAL *.0489194
ULOSS = 1/RVAL1
*|*

EQUATIONS 3
NODES = 3
Tdbnd = 0.0
Qmax = 4.5*3600

*|* SRCC Rated Solar Collector Parameters
EQUATIONS 9
AREA1 =  2.9100E+0001
*|< SRCC rated collector                      |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|1|2|99
AREA = AREA1*.0929
FRta =  8.7100E-0001
*|< FRta of collector (Intercept efficiency)  |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|3|99
FRUL1 =  3.7350E+0000
*|< FRUL of collector (- slope of eff. curve) |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|4|99
FRUL = 20.4418*FRUL1
B0 =  3.1600E-0002
*|< 1st order inc ang modifier coeff (-S)     |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|5|99
B1 =  1.0400E-0002
*|< 2nd order inc ang modifier coeff (-S2)    |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|6|99
COL =  1.0000E+0000
*| Number of collectors in array              |||0|1|0|000100|3
SLOPE=  2.3000E+0001
*| Collector slope                            |degrees|degrees|0|1|0|0090.0|3
*|*

*|* Heat Exchanger Parameters
EQUATIONS 3
EFF = -1.0000E+0000
*| Heat exchanger effectiveness (-1 => no hx) |||0|1|-1|01.000|3
CPH1 =  5.7700E-0001
*| Specific heat of collector side fluid      |Btu/lbm-R|Btu/lbm-
R|0|1|0|10.000|3
CPHOT = 4.1868*CPH1
*|*

*|* Pump Parameters
EQUATIONS 2
PMPPOW = 50
*| Pumping power                              |W|W|0|1|0|10000.0|3
PPUMP = PMPPOW*3.6
*|*
```

```
*|* Daily Water Draw
EQUATIONS 3
FACTOR = 3.7853
MLTPLY =  6.9000E+0001
*| Average daily water draw (69 gal/day standard)
|gal/day|gal/day|0|1|0|100.0|3
*|*
SCALE = FACTOR*MLTPLY/69
* Standard draw based on approximately 69 gal/day.  MLTPLY allows the
*  user to scale the draw as seen fit.  By setting the value to 69 the
*  draw remains the same.

*** SIMULATION PARAMETERS ***
EQUATIONS 4
START = 1
START1 = START-48
STOP = 8760
STEP = .1

EQUATIONS 5
RHOG=2.0000E-01
STRTDAY = INT(START1/24)
GAMMAI=0.0000E+0
SC=4871
SHIFT=0.0

** Calculate the critical timestep for the system.
** Use STEP < t_critical as a safety factor
** Calculation done assuming an instantaneous draw will
**  be no more than 10 gal/hr
*EQUATIONS 6
*MASSTANK = TNKSIZE*FACTOR
*MCOLL = 325
*MLOADMAX = 10*FACTOR
*TCRIT = (MASSTANK/NODES)/(MCOLL+MLOADMAX)
*STEP1 = TCRIT/2
*STEP = MIN(STEP1,1)

SIMULATION START1 STOP STEP
LIMITS 120 120 120
TOLERANCES 0.001 0.001
WIDTH 72

UNIT 19 TYPE 9   DATA READER FOR WEATHER
PARAMETERS 14
* MODE  N  dT(HOURS)   DUMHOURS    Tdb(C)  I(kJ/m2-hr)
  -2    3     1          -1 1 0    -2 1 0  -3 1 0
*      LU FRMT
       14   0
*OUTPUTS: 2,Tdb 3,I


UNIT 29 TYPE 9 DATA READER FOR WATER DRAWS
*WATER DRAWS:  (GAL/HR) - CONVERT TO KG/HR
```

```
* USE FACTOR 3.7853
PARAMETERS 8
* MODE  N   STEP  DRAWS   MULT   ADD   LU   FRMT
  -2    1     1   -1     SCALE   0.    15    0
*OUTPUTS: 1,DRAW(KG/HR)


UNIT 39 TYPE 9  DATA READER FOR MAINS WATER TEMPERATURE
* CHANGES MONTHLY BUT READ IN DAILY (24 HOURS) FROM F-CHART FILE
PARAMTERS 8
* MODE   N  dT(HOURS) TMAINS   LU  FRMT
   -2    1     24     -1 1 0   16   0
*OUTPUTS: 1, TMAINS

UNIT 16 TYPE 16 RADIATION PROCESSOR
PARAMETERS 8
* RADMODE TRACKMODE TILTMODE  DAY      LAT  SC  SHIFT  SMOOTH
    3         1        1     STRTDAY   LAT  SC  SHIFT    2
INPUTS 6
* I(kJ/m2-hr)  td1    td2    RHOG    BETA1    GAMMAI  INext(IF SMOOTH=1)
 19,3          19,19  19,20  RHOG    SLOPE    GAMMAI  19,23
 0.0           0.0    0.0    RHOG    SLOPE    GAMMAI  0.0
*OUTPUTS: 1,Io 2,THETAz 3,GAMMAs 4,I 5,Id 6,IT1 7,IbT1 8,IdT1 9,THETA1
*         10,BETA1 11,IT1


UNIT 1 TYPE 1 COLLECTOR
PARAMETERS 14
* MODE N  AREA  Cp   EFFMD  G   ao    a1    a2  EFF CpHX  OPTMD  bo  b1
   1   1  AREA  4.19   1    50  FRta  FRUL  0.  EFF CPHOT   1    B0  B1
INPUTS 10
* Ti  mCOLL(kg/hr) mHX  Tamb   It    I    Id    RHOG  THETA BETA(SLOPE)
 3,1  3,2          3,2  19,2  16,6 16,4  16,5   0,0    16,9   16,10
 TI   0.0          0.0  20.0   0.0  0.0   0.0   RHOG    0.0    40.0
*OUPUTS: 1, To 2,mo 3,Qgain(KJ/HR) 4,Tco


EQUATIONS 2
DEADH = 0
DEADL = 0

UNIT 2 TYPE 2 PUMP CONTROLLER
PARAMETERS 4
* NSTK dThigh dTlow  Tmax
   11  DEADH  DEADL   100
INPUTS 4
* Th   Tl    TIN  GAMMAI
  1,4  4,1   0,0   2,1
  15.  TI     100    0.
*OUTPUTS: 1,GAMMAo (CONTROL FUNCTION)

UNIT 3 TYPE 3 PUMP
PARAMETERS 4
* mMAX    Cp    Pmax(KJ/HR)   fpar
  325.    4.19    PPUMP        0.
```

```
INPUTS 3
*  Ti    mi   GAMMA
  4,1    4,2   2,1
   TI    0.0    0.0
*OUTPUTS: 1,To 2,mo 3,Ppump

EQUATIONS 1
HGT = -HEIGHT

UNIT 4 TYPE 4  SOLAR STORAGE TANK
PARAMETERS 20
*MODE   VOL   CPF    RHO    UT    HI     AUXMOD    NODE1   NODETI
  2    TSIZE  4.19  1000  ULOSS  HGT      1        1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0     QMAX        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH   TL    ML     TENV
 1,1   1,2  39,1  MLOAD  0,0
 0.0   0.0  TI    0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*UNIT 4 OUTPUTS:
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 24 TYPE 24  INTEGRATOR
PARAMETERS 1
*DT RESET
   1
INPUTS 2
4,8  3,3
0.0  0.0

EQUATIONS 2
* Electric input required (auxiliary heater + collector pump power)
ELECDMND = ([24,1]+[24,2])/3600
QAUX = ([24,1])/3600


UNIT 25 TYPE 25  PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP 10
INPUTS 1
elecdmnd
elcdmd


UNIT 26 TYPE 25  plotting PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP  22
```

```
INPUTS 1
elecdmnd
elcdmd

*|* Display Options
EQUATIONS 2
IREF = 1/STEP
SWITCH =  1.0000E+0000
*| On-line graphic display (1=yes, 2=no)      |||0|1|1|2|3

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
*NTOP  NBOT  YMIN1  YMAX1  YMIN2  YMAX2  IREF  IUP  UNITS
 2     1     0       5     0        80   IREF     1     3
*NPIC  GRID  STOP  SYMBOLS  OUTPUT  ON/OFF
  1     7     0       2       0     SWITCH
INPUTS 3
 QAUX  ELECDMND  MLOAD
 Qaux  ElecDmnd  MTANK
LABELS 4
 kW  kg/hr
 Average System Demand
 Tank Draw

END
```

Two Tank System with SRCC Collector

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC2TNK.LST       6
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC2TNK.OUT      10
ASSIGN C:\ EUSESIA\ SYSTEMS\ SRCC2TNK.PLT      22
ASSIGN C:\ EUSESIA\ SYSTEMS\ HRDRAW.DAT        15



*************************************************************
*  This file predicts the required electric input to a solar *
* domestic hot water system                                  *
*************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|1|2|99
EQUATIONS 1
LAT =  4.2950E+0001
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|3|99
ASSIGN c:\ EUSESIA\ systems\ MLKMAIN.DAT 16
*|< City in which utility is located in       |C:\ EUSESIA\ SYSTEMS\
CITIES.DAT|0|4|99
*|*


***  SYSTEM PARAMETERS  ***
EQUATIONS  6
TSET = 60
TENV = 18
TI = 6.9
*
*  Determine the required draw from the tank.  The following equations
*  account for the tempering valve.  They result from simplified mass
*  and energy balances where Cp is assumed constant.
TDIFF = MAX(0.000001,([4,3]-[39,1]))
TNKDRW = MIN(1,((TSET-[39,1])/TDIFF))
MLOAD = [29,1]*TNKDRW
*
***   STANDARD ELECTRIC HOT WATER TANK   ***
* Volume:  80 gallon tank -> .3028 m3;
* Height:  4.89 ft -> 1.4905 m
* R-value: 16.7 (hr-ft2-F/Btu) -> ULOSS=1/R
*              .0489194(hr-m2-C/kJ)/(hr-ft2-F/Btu)

*|* Solar Storage Tank Parameters
EQUATIONS 7
TNKSIZES =  8.0000E+0001
*| Tank size                                |gal|gal|0|1|0|1000.00|3
TSIZES = .0037854*TNKSIZES
HEIGHT1S =  4.8900E+0000
```

```
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHTS = .3048*HEIGHT1S
RVALS =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVALS1 = RVALS *.0489194
ULOSSS = 1/RVALS1
*|*

*|* Auxiliary Tank Parameters
EQUATIONS 7
TNKSIZEA =  8.0000E+0001
*| Tank size                                  |gal|gal|0|1|0|1000.00|3
TSIZEA = .0037854*TNKSIZEA
HEIGHT1A =  4.8900E+0000
*| Tank height                                |ft|ft|0|1|0|0030.00|3
HEIGHTA = .3048*HEIGHT1A
RVALA =  1.6700E+0001
*| Insulation R-Value                         |hr-ft2-F/Btu|hr-ft2-
F/Btu|0|1|0|1000.00|3
RVALA1 = RVALA *.0489194
ULOSSA = 1/RVALA1
*|*

** Other tank parameters.  S -> solar, A -> auxiliary
EQUATIONS 4
NODES = 3
NODEA = 3
Tdbnd = 0.0
Qmax = 4.5*3600

*|* SRCC Rated Solar Collector Parameters
EQUATIONS 9
AREA1 =  2.9100E+0001
*|< SRCC rated collector                      |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|1|2|99
AREA = AREA1*.0929
FRta =  8.7100E-0001
*|< FRta of collector (Intercept efficiency)  |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|3|99
FRUL1 =  3.7350E+0000
*|< FRUL of collector (- slope of eff. curve  |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|4|99
FRUL = 20.4418*FRUL1
B0 = .0316
*|< 1st order inc ang modifier coeff (-S)     |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|5|99
B1 = .0104
*|< 2nd order inc ang modifier coeff (-S2)    |C:\ EUSESIA\ SYSTEMS\
SRCC.DAT|0|6|99
COL =  1.0000E+0000
*| Number of collectors in array              |||0|1|0|000100|3
SLOPE=  2.3000E+0001
*| Collector slope                            |degrees|degrees|0|1|0|0090.0|3
*|*
```

```
*|* Heat Exchanger Parameters
EQUATIONS 3
EFF = -1.0000E+0000
*| Heat exchanger effectiveness (-1 => no hx) |||0|1|-1|01.000|3
CPH1 =  5.7700E-0001
*| Specific heat of collector side fluid      |Btu/lbm-R|Btu/lbm-
R|0|1|0|10.000|3
CPHOT = 4.1868*CPH1
*|*

*|* Pump Parameters
EQUATIONS 2
PMPPOW = 50
*| Pumping power                              |W|W|0|1|0|10000.0|3
PPUMP = PMPPOW*3.6
*|*

*|* Daily Water Draw
EQUATIONS 3
FACTOR = 3.7853
MLTPLY =  6.9000E+0001
*| Average daily water draw (69 gal/day standard)
|gal/day|gal/day|0|1|0|100.0|3
*|*
SCALE = FACTOR*MLTPLY/69
* Standard draw based on approximately 69 gal/day.  MLTPLY allows the
*  user to scale the draw as seen fit.  By setting the value to 69 the
*  draw remains the same.


EQUATIONS 4
*** SIMULATION PARAMETERS ***
START = 1
START1 = START-48
STOP = 8760
STEP = .1

EQUATIONS 5
RHOG=2.0000E-01
STRTDAY = INT(START1/24)
GAMMAI=0.0000E+0
SC=4871
SHIFT=0.0


** Calculate the critical timestep for the system.
** Use STEP < t_critical as a safety factor
** Calculation done assuming an instantaneous draw will
**  be no more than 10 gal/hr
*EQUATIONS 10
*MASSTANKS = TNKSIZES*FACTOR
*MCOLL = 325
*MLOADMAX = 10*FACTOR
*TCRITS = (MASSTANKS/NODES)/(MCOLL+MLOADMAX)
```

```
*STEPS = TCRITS/2
*
*MASSTANKA = TNKSIZEA*FACTOR
*TCRITA = (MASSTANKA/NODEA)/MLOADMAX
*STEPA = TCRITA/2
*
*STEP1 = MIN(STEPS,STEPA)
*STEP = MIN(STEP1,1)


SIMULATION START1 STOP STEP
LIMITS 120 120 120
TOLERANCES 0.001 0.001
WIDTH 72

UNIT 19 TYPE 9   DATA READER FOR WEATHER
PARAMETERS 14
* MODE  N  dT(HOURS)   DUMHOURS    Tdb(C)  I(kJ/m2-hr)
  -2    3     1          -1 1 0    -2 1 0  -3 1 0
*      LU FRMT
       14   0
*OUTPUTS: 2,Tdb 3,I


UNIT 29 TYPE 9 DATA READER FOR WATER DRAWS
*WATER DRAWS:  (GAL/HR) - CONVERT TO KG/HR
* USE FACTOR 3.7853
PARAMETERS 8
* MODE  N   STEP  DRAWS   MULT   ADD   LU   FRMT
  -2    1     1   -1     SCALE   0.    15    0
*OUTPUTS: 1,DRAW(KG/HR)


UNIT 39 TYPE 9  DATA READER FOR MAINS WATER TEMPERATURE
* CHANGES MONTHLY BUT READ IN DAILY (24 HOURS) FROM F-CHART FILE
PARAMTERS 8
* MODE   N  dT(HOURS) TMAINS   LU  FRMT
   -2    1     24     -1 1 0   16   0
*OUTPUTS: 1, TMAINS

UNIT 16 TYPE 16 RADIATION PROCESSOR
PARAMETERS 8
* RADMODE TRACKMODE TILTMODE  DAY      LAT  SC  SHIFT  SMOOTH
    3         1        1     STRTDAY   LAT  SC  SHIFT    2
INPUTS 6
* I(kJ/m2-hr)  td1    td2    RHOG    BETA1    GAMMAI  INext(IF SMOOTH=1)
 19,3          19,19  19,20  RHOG    SLOPE    GAMMAI  19,23
 0.0           0.0    0.0    RHOG    SLOPE    GAMMAI  0.0
*OUTPUTS: 1,Io 2,THETAz 3,GAMMAs 4,I 5,Id 6,IT1 7,IbT1 8,IdT1 9,THETA1
*         10,BETA1 11,IT1


UNIT 1 TYPE 1   COLLECTOR
PARAMETERS 14
* MODE N  AREA  Cp   EFFMD  G   ao    a1    a2  EFF CpHX  OPTMD  bo  b1
```

```
   1   1  AREA  4.19   1    50  FRta  FRUL  0.  EFF CPHOT   1    B0  B1
INPUTS 10
* Ti  mCOLL(kg/hr) mHX  Tamb   It    I    Id    RHOG  THETA BETA(SLOPE)
 3,1  3,2          3,2  19,2  16,6 16,4  16,5   0,0    16,9   16,10
 TI   0.0          0.0  20.0   0.0  0.0   0.0   RHOG    0.0    40.0
*OUPUTS: 1, To 2,mo 3,Qgain(KJ/HR) 4,Tco


EQUATIONS 2
DEADH = 0
DEADL = 0

UNIT 2 TYPE 2 PUMP CONTROLLER
PARAMETERS 4
* NSTK dThigh dTlow  Tmax
   11  DEADH  DEADL   100
INPUTS 4
* Th   Tl    TIN  GAMMAI
  1,4  5,1   0,0   2,1
  15.  TI    100    0.
*OUTPUTS: 1,GAMMAo (CONTROL FUNCTION)

UNIT 3 TYPE 3 PUMP
PARAMETERS 4
* mMAX    Cp    Pmax(KJ/HR)   fpar
  325.    4.19    PPUMP        0.
INPUTS 3
*  Ti    mi   GAMMA
  5,1    5,2   2,1
   TI    0.0    0.0
*OUTPUTS: 1,To 2,mo 3,Ppump

EQUATIONS 2
HGTA = -HEIGHTA
HGTS = -HEIGHTS

UNIT 5 TYPE 4   SOLAR STORAGE TANK
PARAMETERS 20
*MODE   VOL    CPF    RHO    UT     HI    AUXMOD  NODE1   NODETI
  2    TSIZES  4.19  1000  ULOSSS  HGTS     1       1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0      0.0        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH   TL    ML     TENV
 1,1   1,2  39,1  MLOAD  0,0
 0.0   0.0  TI    0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1

UNIT 4 TYPE 4   AUXILIARY TANK
PARAMETERS 20
```

```
*MODE   VOL    CPF    RHO    UT     HI    AUXMOD  NODE1   NODETI
  2    TSIZEA  4.19  1000  ULOSSA  HGTA     1       1       1
*TSET   DTDB   QAUX1     NODE2   NODET2   TSET2   DTDB2   QAUX2
 TSET    0     QMAX        1       1       TSET     0     0.0
*UAFLUE   TFLUE   TBOIL
  0.0     TENV   100
INPUTS 5
* TH   MH    TL     ML     TENV
 0,0   0,0   5,3    5,4    0,0
 0.0   0.0   TI     0.0    TENV
DERIVATIVES NODES
TSET TSET TSET TSET TSET TSET TSET TSET TSET
*UNIT 4 OUTPUTS:
*OUTPUTS: 1,Trtn 2,m_rtnCOLL 3,Tload 4,m_load 5,Qenv,loss 6,Qs
*         7,dEtank 8,Qaux1


UNIT 24 TYPE 24  INTEGRATOR
PARAMETERS 1
*DT RESET
   1
INPUTS 2
4,8  3,3
0.0  0.0

EQUATIONS 2
* Electric input required (auxiliary heater + collector pump power)
ELECDMND = ([24,1]+[24,2])/3600
QAUX = ([24,1])/3600


UNIT 25 TYPE 25  PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP 10
INPUTS 1
elecdmnd
elcdmd

UNIT 26 TYPE 25  plotting PRINTER
PARAMETERS 4
* DT  TON  TOFF  LU
   1 START STOP  22
INPUTS 1
elecdmnd
elcdmd

*|* Display Options
EQUATIONS 2
IREF = 1/STEP
SWITCH =  1.0000E+0000
*| On-line graphic display (1=yes, 2=no)      |||0|1|1|2|3

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
```

```
*NTOP  NBOT  YMIN1  YMAX1  YMIN2  YMAX2  IREF  IUP  UNITS
 2     1     0       5     0        80   IREF     1     3
*NPIC  GRID  STOP  SYMBOLS  OUTPUT  ON/OFF
  1     7     0       2       0     SWITCH
INPUTS 3
 QAUX  ELECDMND  MLOAD
 Qaux  ElecDmnd  MTANK
LABELS 4
 kW  kg/hr
 Average System Demand
 Tank Draw

END
```

Photovoltaic System

```
*TRNSED
ASSIGN C:\ EUSESIA\ SYSTEMS\ PV1.LST       6
ASSIGN C:\ EUSESIA\ SYSTEMS\ PV1.OUT      10
ASSIGN C:\ EUSESIA\ SYSTEMS\ PV1.PLT      22



*************************************************************
*  This file predicts the required electric input to a solar *
* photovoltaic system                                        *
*************************************************************

*|* Utility Location
ASSIGN c:\ EUSESIA\ systems\ MLKWTR91.DAT 14
*|< City in which utility is located         |c:\ EUSESIA\ systems\
cities.dat|1|2|99
EQUATIONS 1
LAT =  4.2950E+0001
*|< City in which utility is located         |c:\ EUSESIA\ systems\
cities.dat|0|3|99
*|*

EQUATIONS 4
RHOG = .2
SC = 4871
SHIFT = 0
GAMMAI = 0

EQUATIONS 5
START =  1
STOP =  8760
STEP =  1
START1 = START-48
STRTDAY =INT(START1/24)


SIMULATION START1 STOP STEP
LIMITS  120  120  120
TOLERANCES 0.001  0.001
WIDTH 72


Equations 22
*|* Photovoltaic Panels
SunRef=  1.0000E+0003
*|< Photovoltaic panel selection             |c:\ EUSESIA\ systems\
PVMODUL2.DAT|1|2|0
Tcref =  2.9800E+0002
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|3|0
Iscref =  1.8000E+0000
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|4|0
Vocref =  5.5500E+0001
```

```
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|5|0
Imref =  1.3200E+0000
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|6|0
Vmref=  3.8000E+0001
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|7|0
Misc =  1.5000E-0003
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|8|0
Mvoc = -1.9425E-0001
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|9|0
tau_alfa =  9.0000E-0001
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|10|0
E_q =  1.1550E+0000
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|11|0
NCS=  6.6000E+0001
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|12|0
width =  8.0000E-0001
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|13|0
length =  1.5250E+0000
*|<Photovoltaic panel selection   |c:\ EUSESIA\ systems\ PVMODUL2.DAT|0|14|0
Ns_pv =  6.0000E+0000
*| Number of panels in series               |||0|1|1|1000|0
Np_pv =  1.0000E+0000
*| Number of panels in parallel             |||0|1|1|1000|0
Mode_pv =  2.0000E+0000
MPPT_Eff =  9.5000E-0001
*| Eff. of the max. power point tracker      |||0|1|0|1.00|0
DINRG = 100
U_L =  10
SLOPE=  2.3000E+0001
*| Slope of collector                       |Degrees||0|1|-180.00|180.00|0
*|*
*|* DC/AC Inverter
Invr_Eff =  9.5000E-0001
*| Inverter efficiency                      |||0|1|0|1.00|0
V_grid =  1.1000E+0002
*| Grid operating voltage                   |Volts||0|1|100|250.|0

*******************************************************

UNIT 19 TYPE 9   DATA READER FOR WEATHER
PARAMETERS 14
* MODE  N  dT(HOURS)   DUMHOURS    Tdb(C)  I(kJ/m2-hr)
  -2    3     1          -1 1 0    -2 1 0  -3 1 0
*      LU FRMT
       14   0
*OUTPUTS: 2,Tdb 3,I
*******************************************************

UNIT 16 TYPE 16 Radiation Processor
PARAMETERS 8
*RADMODE  TRACKMODE  TILTMODE    DAY    LAT  SC   SHIFT  SMOOTH
    3        1          1      STRTDAY  LAT  SC   SHIFT    2
INPUTS 6
*I(kJ/hr-m2)   td1   td2   RHOG   BETA1  GAMMAI   INEXT(IF SMOOTH=1)
   19,3      19,19  19,20  RHOG   SLOPE  GAMMAI   19,23
```

```
    0.0        0.0   1.0   RHOG   SLOPE  GAMMAI   0.0
*OUTPUTS: 1)Io  2)THETAz  3)GAMMAs  4)I  5)Id  6)IT1  7)IbT1
*         8)IdT1  9)THETA1  10)BETA1  11)IT1
*******************************************************

EQUATION 2
solar = [16,6]/3.6
T_amb = [19,2]

*******************************************************

unit 62 type 62 PV array
* PV paramters
Parameters 9
Mode_pv   Sunref  Tcref  Iscref  Vocref  Imref  Vmref  Misc  Mvoc

Parameters 8
tau_alfa   E_q   NCS  width   length    Ns_pv    Np_pv    DINRG


Inputs 3
*Sun    Tamb    U_L
16,6    T_amb   U_L
3600    25.0    10.0


*******************************************************

unit 70 type 70 DC/DC + DC/AC
Parameter 1
3

Inputs 5
* Imp    Vmp  V_grid   Eta_DC_DC   Eta_DC_AC
62,4  62,5     0,0       0,0         0,0
2.    50.     V_grid   MPPT_Eff    Invr_Eff


*******************************************************

Equation 1
Qsolar = solar * width * length * Ns_pv * Np_pv


*******************************************************

unit 23 type 24 Quantity Integrator, Hourly

Parameters 1
*Dt
1
inputs 2
*Qsolar  Qelec
Qsolar    70,3
 10000    100.
```

```
*******************************************************
Equations 2
Qsol_k   = [23,1] / 1000
Qelc_k   = [23,2] / 1000

*******************************************************

UNIT 26 TYPE 25 PRINTER

PARAMETERS 4
1 start STOP 10

INPUTS 1
*Qelec
 Qelc_k
 ElcDmd


*******************************************************

Equation 1
Ymax1 = Int((width * length * Np_pv * Ns_pv)/5 + 0.9) * 5000

*******************************************************
*|*
*|* Display Options
EQUATIONS 1
SWITCH =  1.0000E+0000
*| On-line graphic display (1=yes, 2=no)     |||0|1|1|2|3
unit 65 type 65 ONLINE GRAPHICS

PARAMETERS 15
*Ntop   Nbot   Ymin,1   Ymax,1   Ymin,2   Ymax,2
  1      0       0.0    5.0    -25.     100.
*Iref   Iupd   units   Npic   Grid   Stop   Symbols   Outputs
  1      1       3     1       7      0       2         0
*Plot (Yes/No)
 SWITCH
inputs 1
Qelc_k
Electrical
labels 4
kW  none
Average System Generation
*******************************************************

END
```

Marginal Plant Prediction

```
*TRNSED

ASSIGN \ EUSESIA\ UTILMIX\ MARPLANT.LST    6
ASSIGN \ EUSESIA\ utilmix\ marplant.plt   10

******************************
******     FRONT END     ******
******************************
*|*             Prediction of the Marginal Plant
*|*            for a Specified Region of Utilities
*|*
*|*
*** Assign the plant data file and the load file ***
*|* Utility Region to be Analyzed
ASSIGN c:\ EUSESIA\ utilmix\ WEPCO.DAT 15
*|< Utility region                    |C:\ EUSESIA\ UTILMIX\ REGIONS.DAT|1|2|0
ASSIGN c:\ EUSESIA\ utilmix\ WEPCO.LOD 16
*|< Utility region                    |C:\ EUSESIA\ UTILMIX\ REGIONS.DAT|0|3|0
ASSIGN c:\ EUSESIA\ utilmix\ WEPCO.PRF 14
*|< Utility region                    |C:\ EUSESIA\ UTILMIX\ REGIONS.DAT|0|4|0
EQUATIONS 1
LIMIT = 8000
*| Estimate region capacity           |MW|MW|0|1|0|100000||0

EQUATIONS 3
START = 1
STOP = 8760
STEP =  1

SIMULATION  START STOP STEP
TOLERANCES  .001 .001



******************************
******   DATA READERS   ******
******************************
UNIT 11 TYPE 99   LOAD PROFILE DATA READER
PARAMETERS 11
* MODE   NUMVALS   DT  LOAD * +    EUE * +   LU   FRMT
   -2       2      1     -1 1 0     -2 1 0   16     0
*OUTPUTS:  1)LOAD  2)MARGINAL EUE


***********************************
******   FIND PLANT PROFILE  ******
***********************************
UNIT 72 TYPE 72   MARGINAL PLANT PREDICTOR
PARAMETERS 1
*LU
 15
INPUTS 2
```

```
*LOAD  MAREUE
11,1    11,2
1.0      0.0
*OUTPUTS: 1)LOAD  2)MARGINAL PLANT   3)MAGINAL EUE  4)MARGINAL OPERATING COST
*         5)TOTAL ADJUSTED CAPACITY


************************************
******   OUTPUT AND DISPLAY   ******
************************************
UNIT 25 TYPE 25   PRINTER
PARAMETERS 4
* DT   T_ON    T_OFF   LU   UNITS
  1   START    STOP    14    0
INPUTS 5
*LOAD  MARPLANT  MAREUE  MARCOST  TOTCAP
 72,1    72,2     72,3    72,4     72,5
LOAD  MARPLANT  MAREUE  MARCOST  TOTCAP
*OUTPUTS:  1)LOAD 2)MARPLANT 3)MAREUE  4)MARCOST  5)TOTCAP



UNIT 26 TYPE 25   plotting PRINTER
PARAMETERS 4
* DT   T_ON    T_OFF   LU   UNITS
  1   START    STOP    10    0
INPUTS 4
*LOAD    MAREUE    MARCOST     TOTAL ADJUSTED CAPACITY
 72,1     72,3       72,4              72,5
 LOAD    MAREUE     MARCST           CAPACITY
*OUTPUTS:  1)LOAD  2)MAREUE  3)MARCOST  4)CAPACITY


UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
* #_TOP #_BOT YMN1 YMX1 YMN2 YMX2 IREF IUP UNITS NPIC GRID STOP SYM OUT ON/OFF
    2     1    0  LIMIT    0 .25   1    1    3     1    7   1    2   0  1
INPUTS 3
* LOAD   CAPACITY  MARCOST
  11,1     72,5      72,4
  LOAD     CAP     MARCST
LABELS 4
MW  $
Utility Load
Marginal Operating Cost

END
```

Utility Impact Analysis

```
*TRNSED

ASSIGN C:\ EUSESIA\ UTILITY.LST    6
ASSIGN C:\ EUSESIA\ UTILITY.PLT   11
ASSIGN C:\ EUSESIA\ UTIL1.DAT     15
ASSIGN C:\ EUSESIA\ UTIL2.DAT     16
ASSIGN C:\ EUSESIA\ UTIL3.DAT     17
ASSIGN C:\ EUSESIA\ UTIL4.DAT     18
ASSIGN C:\ EUSESIA\ UTIL5.DAT     19
ASSIGN C:\ EUSESIA\ UTIL6.DAT     20
ASSIGN C:\ EUSESIA\ UTIL7.DAT     28

*******************************
******     FRONT END     ******
*******************************
*|*         Electric Utility Solar Energy System Impact Analysis:
*|*
*|*        Economic and Environmental Benefits from a Large Scale
*|*               Implementation of Solar Energy Systems
*|*
*|*
*|*             Date:              |10/95
*|*             Organization:      |SEL
*|*             Input prepared by: |Trzesniewski
*|*
*|*
*|* Utility Information
ASSIGN c:\ EUSESIA\ utilmix\ WEPCO.LOD 12
*|< Utility to be analyzed            |C:\ EUSESIA\ UTILMIX\ LOADS.DAT|1|2|0
ASSIGN c:\ EUSESIA\ utilmix\ WISCRGN.PRF 14
*|< Utility region to be analyzed     |C:\ EUSESIA\ UTILMIX\ REGIONS.DAT|1|4|0
ASSIGN c:\ EUSESIA\ utilmix\ WISCRGN.DAT 13
*|< Utility region to be analyzed     |C:\ EUSESIA\ UTILMIX\ REGIONS.DAT|0|2|0
EQUATIONS 1
LIMIT =  2.0000E+0004
*| Estimate region capacity           |MW|MW|0|1|0|100000|0
*|*
EQUATIONS 5
CUSTOMERS =  1.0000E+0005
*| Number of electric customers       |||0|1|0|100000000|0
TRNLSS =  2.0000E+0000
*| System transmission losses         |%|%|0|1|0|000100.00|0
DISLSS =  3.0000E+0000
*| System distribution losses         |%|%|0|1|0|000100.00|0
TRNSLOSS = TRNLSS/100
DISTLOSS = DISLSS/100
*|*

*|* Solar Energy System
ASSIGN c:\ EUSESIA\ systems\ mlk1tnk.out 22
*|< Solar system                     |C:\ EUSESIA\ SYSTEMS\ SOLSYS.DAT|1|2|0
EQUATIONS 9
```

```
SOLMODE =  1.0000E+0000
*|< Solar system                      |C:\ EUSESIA\ SYSTEMS\ SOLSYS.DAT|0|3|0
SYSCOST =  2.0000E+0003
*| Installed cost of solar system     |$/unit|$/unit|0|1|0|100000|0
ACCEPT =  5.0000E+0000
*| % of customers accepting program   |%|%|0|1|0|0100.0|0
DOWNPAY =  1.4000E+0002
*| Customer down payment on system    |$|$|0|1|0|001000|0
LEAS =  1.2000E+0001
*| Customer monthly lease payment     |$/mo|$/mo|0|1|0|100.00|0
LEASE = LEAS*12
OANDM =  1.0000E+0001
*| Operation and maintenance          |$/yr-system|$/yr-system|0|1|0|001000|0
DEPYRS =  5.0000E+0000
*| Equipment depreciation period      |yrs|yrs|0|1|0|000100|0
NUMSYS = CUSTOMERS*ACCEPT/100
*|*

*|* Comparative System
ASSIGN c:\ EUSESIA\ systems\ mlkedhw.out 21
*|< Electric system                   |C:\ EUSESIA\ SYSTEMS\ ELECSYS.DAT|1|2|0
*|*

*|* Emission Costs
EQUATIONS 8
CO2 =  0.0000E+0000
*| CO2                                |$/lbm|$/ton|0|2000|0|10000.0000|0
SO2 =  2.0000E-0002
*| SO2                                |$/lbm|$/ton|0|2000|0|10000.0000|0
NOX =  0.0000E+0000
*| NOX                                |$/lbm|$/ton|0|2000|0|10000.0000|0
N2O =  0.0000E+0000
*| N2O                                |$/lbm|$/ton|0|2000|0|10000.0000|0
PARTS =  0.0000E+0000
*| Particulates                       |$/lbm|$/ton|0|2000|0|10000.0000|0
CH4 =  0.0000E+0000
*| CH4                                |$/lbm|$/ton|0|2000|0|10000.0000|0
MERCURY =  0.0000E+0000
*| Mercury                            |$/lbm|$/ton|0|2000|0|10000.0000|0
NUKES =  0.0000E+0000
*| Nuclear waste                      |$/lbm|$/ton|0|2000|0|10000.0000|0
*|*

*|* Demand Reduction Parameters
EQUATIONS 8
RESRVMARGN=  1.5000E+0001
*| Reserve margin                              |%|%|0|1|0|000100.00|0
RESRVMAR = RESRVMARGN/100
DMNDWORTH =  2.5000E+0002
*| Cost of conventional option per kW          |$/kW|$/kW|0|1|0|100000.00|0
TRNSWORTH =  1.0000E+0002
*| Cost of adding kW of transmission capacity  |$/kW|$/kW|0|1|0|100000.00|0
DISTWORTH =  1.0000E+0002
*| Cost of adding kW of distribution capacity  |$/kW|$/kW|0|1|0|100000.00|0
DMODE =  2.0000E+0000
```

```
*|< Demand evaluation method                    |C:\ EUSESIA\ METHOD.DAT|1|2|0
PEAKS =  2.0000E+0001
*| Number of peak hours to evaluate            |||0|1|0|000000100|0
CCIREF =  9.2000E-0001
*| CCI of conventional reference option        |||0|1|0|0001.0000|0
*|*

*|* Electric Customer Retention
EQUATIONS 3
NOPROGLOSS=  4.0000E+0000
*| % customers lost to other fuel w/o program  |%|%|0|1|0|00100|0
PROGLOSS =  2.0000E+0000
*| % customers lost to other fuel with program |%|%|0|1|0|00100|0
RETAINWRTH=  0.0000E+0000
*| Value of retained customer                  |$/yr|$/yr|0|1|0|10000|0
*|*

*|* Delayed Power Plant Construction
CONSTANTS 1
DELAYWORTH=  0.0000E+0000
*| Value of delaying power plant construction  |$/peak kW|$/peak
kW|0|1|0|100000|0
*|*

*|* Government Incentives for Investment
CONSTANTS 3
TAXCRD =  1.0000E+0001
*| Tax credit given for investment             |%|%|0|1|0|0100.00|0
TAXCREDIT = TAXCRD/100
SUBSIDY =  1.5000E-0002
*| Energy subsidy                              |$/kWh|$/kWh|0|1|0|100.000|0
*|*

*|* Economic Parameters
CONSTANTS 7
NUMYRS =  2.0000E+0001
*| Years of economic analysis                  |yrs|yrs|0|1|1|000100|0
IRATE =  5.0000E+0000
*| Inflation rate                              |%|%|0|1|0|100.00|0
INFRATE = IRATE/100
DRATE =  8.0000E+0000
*| Discount rate                               |%|%|0|1|0|100.00|0
DISRATE = DRATE/100
TAXBR =  3.4000E+0001
*| Utility tax bracket                         |%|%|0|1|0|100.00|0
TAXBRACK = TAXBR/100
*|*

*|* Customer Rate Information
EQUATIONS 2
WINRATE =  6.4000E-0002
*| Winter rate                                 |$/kWh|$/kWh|0|1|0|1.0000|0
SUMRATE =  7.4500E-0002
*| Summer rate                                 |$/kWh|$/kWh|0|1|0|1.0000|0
```

```
EQUATIONS 3
START = 1
STOP = 8760
STEP =  1

SIMULATION  START STOP STEP
TOLERANCES  .001 .001
WIDTH 132


******************************
******   DATA READERS   ******
******************************
UNIT 9 TYPE 99   EDHW SYSTEM OUTPUT DATA READER
PARAMETERS 11
* MODE   NUMVALS   DT   HR * +   ELECDMND * +   LU   FRMT
   -2       2      1    -1 1 0         -2 1 0   21     0
*OUTPUTS:  2)ELECDMND

UNIT 10 TYPE 99   SDHW SYSTEM OUTPUT DATA READER
PARAMETERS 11
* MODE   NUMVALS   DT   HR * +   SOLDMND * +   LU   FRMT
   -2       2      1    -1 1 0        -2 1 0   22     0
*OUTPUTS:  2)SOLDMND

UNIT 11 TYPE 99  REGIONAL LOAD PROFILE DATA READER
PARAMETERS 17
* MODE   NUMVALS   DT   HR * +   LOAD * +   PLANT * +  MAREUE * +
   -2       4      1    -1 1 0     -2 1 0      -3 1 0      -4 1 0
* LU   FRMT
  14     0
*OUTPUTS:  2)LOAD  3)MARGINAL PLANT  4)MARGIANL EUE

UNIT 12 TYPE 99   UTILITY LOAD PROFILE DATA READER
PARAMETERS 8
* MODE   NUMVALS   DT  LOAD * +   LU   FRMT
   -2       1       1    -1 1 0   12     0
*OUTPUTS:  1)LOAD

*********************************
*** SINGLE SYSTEM PERFORMANCE ***
*********************************
EQUATIONS 2
ELECDMND = [9,2]
SOLDMND = [10,2]

UNIT 30 TYPE 24  MONTHLY INTEGRATOR
PARAMETERS 1
*DTRESET
   -1
INPUTS 2
*ELECDMND  SOLDMND
 ELECDMND  SOLDMND
    1.        1.
```

```
EQUATIONS 2
SOLMNTH = [30,2]
ELCMNTH = [30,1]



***************************
******   ECONOMICS   ******
***************************
UNIT 71 TYPE 71   UTILITY ENERGY & ECONOMIC IMPACT ANALYSIS
PARAMETERS 20
* #SYSTS    CO2    SO2   NOX   N2O   PARTS   CH4   MERCURY   NUKES
  NUMSYS    CO2    SO2   NOX   N2O   PARTS   CH4   MERCURY   NUKES
* RESERVE MARGIN  DMNDWORTH   TRNSWORTH  DISTWORTH  DMODE   PEAKS
      RESRVMAR    DMNDWORTH   TRNSWORTH  DISTWORTH  DMODE   PEAKS
* REFERENECE CCI  TRNSLOSS  DISTLOSS  SOLMODE  LU
      CCIREF      TRNSLOSS  DISTLOSS  SOLMODE  13
INPUTS 5
*  ELECDMND  SOLDMMD  LOAD  MARPLANT  MAREUE
   ELECDMND  SOLDMND  11,2    11,3    11,4
     0.0       0.0    0.0     0.0      0.0
*OUTPUTS:  1)ENERGY RED(kWh) 2)ENERGY SAVINGS($) 3)CO2 RED(lbm) 4)CO2
SAVINGS($)
*          5)SO2 RED(lbm) 6)SO2 SAVINGS($) 7)NOX RED(lbm) 8)NOX SAVINGS($)
*          9)N2O RED(lbm) 10)N2O SAVINGS($) 11)PARTS RED(lbm) 12)PARTS
SAVINGS($)
*         13)CH4 RED(lbm) 14)CH4 SAVINGS($) 15)HG RED(lbm) 16)HG SAVINGS($)
*         17)NUKE RED(lbm) 18)NUKE SAVINGS($) 19)POLLUTION SAVINGS($)
*         20)DEMAND REDUCTION(kW) 21)DEMAND SAVINGS($)
*         22)DEMAND REDUCTION AT PEAK LOAD(kW) 23)OPTION CCI

UNIT 72 TYPE 24   INTEGRATOR
INPUTS 10
* kWh ENERGY   $ ENERGY   LBMCO2   $CO2   LBMSO2   $SO2   LBMNOX   $NOX
     71,1         71,2     71,3    71,4    71,5    71,6    71,7    71,8
* LBMN2O   $N2O
   71,9    71,10
0 0 0 0 0 0 0 0 0 0

UNIT 73 TYPE 24   INTEGRATOR
INPUTS 9
* LBMPARTS   $PARTS   LBMCH4   $CH4   LBMHG   $HG    LBMNUKE   $NUKE
   71,11     71,12     71,13   71,14  71,15   71,16   71,17    71,18
* $POLLUTION
    71,19
0 0 0 0 0 0 0 0 0 0


***  PRE-ECONOMIC SUMMARY EQUATIONS  ***
EQUATIONS 3
DELAYVAL = DELAYWORTH * [71,22]
RETAINVAL = RETAINWRTH*CUSTOMERS*(NOPROGLOSS-PROGLOSS)/100
SUBSDYCRDT = SUBSIDY * [72,1]

UNIT 74 TYPE 89   UTILITY ECONOMIC SUMMARY
```

```
PARAMETERS 12
* LIFE YRS   INFLATION   DISCOUNT   #SYSTS   $/SYSTEM   DOWN PAYMENT
   NUMYRS     INFRATE    DISRATE    NUMSYS    SYSCOST     DOWNPAY
* LEASE   OANDM   RETENTION VALUE      TAX BRACKET   DEPYRS  TAX CREDIT
  LEASE   OANDM    RETAINVAL           TAXBRACK      DEPYRS  TAXCREDIT
INPUTS 5
*  $ENERGY   $DEMAND   $POLLUTION  DELAY VALUE   SUBSIDY CREDIT
    72,2      71,21      73,9        DELAYVAL      SUBSDYCRDT
     0.0       0.0        0.0          0.0             0.0
*OUTPUTS:  1)PRESENT WORTH OF INVESTMENT 2)LEVELIZED COST 3)RATE OF RETURN
*          4)DEMAND SAVINGS AFTER 1ST YEAR 5)PW INVESTMENT 6)PW DELAY VALUE
*          7)PW RETENTION 8)PW DOWNPAYMENTS 9)PW TAX CREDIT 10)PW DEMAND SAV
*          11)PW ENERGY SAV  12)PW EMISSION SAV 13)PW SUBSIDY 14)PW O&M
*          15)PW DEPRECIATION 16)PW LEASE

************************************
******   OUTPUT AND DISPLAY   ******
************************************
UNIT 25 TYPE 25   OUTPUT PRINTER
PARAMETERS 4
* DT   T_ON   T_OFF   LU   UNITS
   1   STOP   STOP    15    1
INPUTS 10
* kWh ENERGY   $ ENERGY   LBMCO2   $CO2   LBMSO2   $SO2   LBMNOX   $NOX
     72,1         72,2     72,3    72,4    72,5    72,6    72,7    72,8
* LBMN2O   $N2O
   72,9    72,10
ENRED ENSAV LBMCO2 $CO2 LBMSO2 $SO2 LBMNOX $NOX LBMN2O $N2O

UNIT 26 TYPE 25   OUTPUT PRINTER
PARAMETERS 4
* DT   T_ON   T_OFF   LU   UNITS
   1   STOP   STOP    16    1
INPUTS 10
* LBMPARTS   $PARTS   LBMCH4   $CH4   LBMHG   $HG   LBMNUKE   $NUKE
    73,1      73,2     73,3    73,4   73,5    73,6    73,7     73,8
* $POLLUTION   NUMSYS
     73,9      NUMSYS
 LBMPARTS   $PARTS   LBMCH4   $CH4   LBMHG   $HG   LBMNUKE   $NUKE
 $POLLUTION NUMSYS

UNIT 27 TYPE 25   OUTPUT PRINTER
PARAMETERS 4
* DT   T_ON   T_OFF   LU   UNITS
   1   STOP   STOP    17    1
INPUTS 10
* DMNDRED   DMNDSAV   CCI   PRESWORTH  LEVELCOST  ROR
   71,20     74,4    71,23    74,1       74,2     74,3
* SUMMER RATE   WINTER RATE   DMNDMODE  SYSCOST
    SUMRATE       WINRATE      DMODE    SYSCOST
DMNDRED  DMNDSAV  CCI  PRESWORTH  LEVELCOST  ROR  SMRATE  WNRATE
DMODE  SYSCOST

UNIT 28 TYPE 25  MONTHLY PRINTER
PARAMETERS 4
```

```
*DT  TON    TOFF  LU
 -1  START  STOP  18
INPUTS 2
*  SOLDMND_MO   ELCDNM_MO
    SOLMNTH      ELCMNTH
    SOLDMND      ELECDMND


UNIT 38 TYPE 25   PRE-ECON PRINTER
PARAMETERS 4
*DT  TON    TOFF   LU
 1   STOP   STOP   19
INPUTS 7
*ENRED  ENSAV  POLLSAV   NUMSYS   DMNDSAV  PEAKRED  CUSTOMERS
  72,1  72,2    73,9     NUMSYS    71,21    71,22   CUSTOMERS
 ENRED  ENSAV  POLLSAV   NUMSYS   DMNDSAV  PEAKRED  CUSTOMERS

UNIT 40 TYPE 25   OUTPUT PRINTER
PARAMETERS 4
*DT  TON    TOFF   LU
 1   STOP   STOP   20
INPUTS 10
*PWDELAY  PWRETENTION  PWDOWNPAY  PWTAXCREDIT  PWDMDNDSAV  PWENSAV
  74,6       74,7        74,8       74,9          74,10     74,11
*PWEMISSAV  PWSUBSIDY  PWO&M  PWDEPRECIATION
   74,12     74,13     74,14      74,15
PWDLAY PWRTN  PWDWM  PWTAXCR  PWDSAV  PWENSV PWESAV PWSUBS PWO&M PWDEPR

UNIT 45 TYPE 25   OUTPUT PRINTER
PARAMETERS 4
*DT  TON    TOFF   LU
 1   STOP   STOP   28
INPUTS 1
*PWLEASE
  74,16
PWLEAS

UNIT 29 TYPE 25   PLOTTING PRINTER
PARAMETERS 5
* DT   T_ON    T_OFF   LU   UNITS
  1    START   STOP    11     1
INPUTS 5
* LOAD  UtilLoad   dmdred   elcdmd    soldmd
  11,2    12,1     71,1    elecdmnd   soldmnd
 RgLoad   UtLoad   dmdred   elcdmd    soldmd
   MW      MW        kW       kW        kW

UNIT 65 TYPE 65  ON-LINE PRINTER
PARAMETERS 15
* #_TOP #_BOT YMN1 YMX1 YMN2 YMX2 IREF IUP UNITS NPIC GRID STOP SYM OUT ON/OFF
    2     2    0    5    0   LIMIT  1    1    3     1    7   1    2   0  1
INPUTS 4
* ELECDMND   SOLDMND    REGION LOAD  PLANT LAOD
    9,2       10,2         11,2        12,1
  Elc_dmnd   Sol_dmnd    RgnLoad      UtlLoad
```

```
LABELS 4
kW MW
System Demands
Loads

END
```

Quick Economic Analysis

```
*TRNSED

* THIS INPUT FILE IS TO PROVIDE A QUICK ECONOMIC CALCULATION
* FOR CHANGES IN ECONOMIC PARAMETERS


ASSIGN C:\ EUSESIA\ ECON.LST       6
ASSIGN C:\ EUSESIA\ ECON.PLT      11
ASSIGN C:\ EUSESIA\ ECON.OUT      12
ASSIGN C:\ EUSESIA\ UTIL5.DAT     15


******************************
******     FRONT END     ******
******************************
*|*         Electric Utility Solar Energy System Impact Analysis:
*|*
*|*    Quick Economic Analysis of a Solar Energy System Implementation
*|*
*|*
*|*             Date:              |9/95
*|*             Organization:      |SEL
*|*             Input prepared by: |Trzesniewski
*|*
*|*

*|* Solar Energy System
CONSTANTS 3
SYSCOST =  2.0000E+0003
*| Installed cost of solar system     |$/unit|$/unit|0|1|0|100000|0
DOWNPAY =  1.4000E+0002
*| Customer down payment on system    |$|$|0|1|0|001000|0
LEAS =  0.0000E+0000
*| Customer monthly lease payment     |$/mo|$/mo|0|1|0|001000|0
EQUATIONS 3
LEASE = LEAS*12
OANDM =  1.0000E+0001
*| Operation and maintenance          |$/yr-system|$/yr-system|0|1|0|001000|0
DEPYRS =  5.0000E+0000
*| Equipment depreciation period      |yrs|yrs|0|1|0|000100|0
*|*


*|* Electric Customer Retention
CONSTANTS 3
NOPROGLOSS=  1.0000E+0001
*| % customers lost to other fuel w/o program  |%|%|0|1|0|00100|0
PROGLOSS =  8.0000E+0000
*| % customers lost to other fuel with program |%|%|0|1|0|00100|0
RETAINWRTH=  2.0000E+0002
*| Value of retained customer                  |$/yr|$/yr|0|1|0|10000|0
*|*
```

```
*|* Delayed Power Plant Construction
CONSTANTS 1
DELAYWORTH=  0.0000E+0000
*| Value of delaying power plant construction  |$/peak kW|$/peak
kW|0|1|0|100000|0
*|*

*|* Government Incentives for Investment
EQUATIONS 3
TAXCRD =  1.0000E+0001
*| Tax credit given for investment             |%|%|0|1|0|0100.00|0
TAXCREDIT = TAXCRD/100
SUBSIDY =  1.5000E-0002
*| Energy subsidy                              |$/kWh|$/kWh|0|1|0|100.000|0
*|*

*|* Economic Parameters
CONSTANTS 4
NUMYRS =  1.5000E+0001
*| Years of economic analysis                  |yrs|yrs|0|1|1|000100|0
IRATE =  5.0000E+0000
*| Inflation rate                              |%|%|0|1|0|100.00|0
DRATE =  8.0000E+0000
*| Discount rate                               |%|%|0|1|0|100.00|0
TAXBR =  3.4000E+0001
*| Utility tax bracket                         |%|%|0|1|0|100.00|0
*|*

*|* Customer Rate Information
EQUATIONS 2
WINRATE =  6.4000E-0002
*| Winter rate                                 |$/kWh|$/kWh|0|1|0|1.0000|0
SUMRATE =  7.4500E-0002
*| Summer rate                                 |$/kWh|$/kWh|0|1|0|1.0000|0


EQUATIONS 3
INFRATE = IRATE/100
DISRATE = DRATE/100
TAXBRACK = TAXBR/100

EQUATIONS 3
START = 1
STOP = 1
STEP =  1

SIMULATION  START STOP STEP
TOLERANCES  .001 .001


******************
** DATA READERS **
******************
UNIT 9 TYPE 99   PRE-ECON DATA READER
```

```
PARAMETERS 29
* MODE   NUMVALS   DT   HR * +   ENRED * +   $ENERGY * +
   -2       8      1    -1 1 0      -2 1 0        -3 1 0
* POLLSAV * +  NUMSYS * +  DMNDSAV * +  PEAKRED * +
       -4 1 0      -5 1 0       -6 1 0       -7 1 0
* CUSTOMERS * +    LU   FRMT
         -8 1 0    15    0
*OUTPUTS:  2)ENRED 3)ENSAV 4)POLLSAV 5)NUMSYS 6)DMNDSAV 7)PEAKLOAD 8)CUSTOMERS




***************
** ECONOMICS **
***************
***  PRE-ECONOMIC SUMMARY EQUATIONS  ***
EQUATIONS 3
DELAYVAL = DELAYWORTH * [9,7]
RETAINVAL = RETAINWRTH*[9,8]*(NOPROGLOSS-PROGLOSS)/100.0
SUBSDYCRDT = SUBSIDY * [9,2]


UNIT 71 TYPE 88   QUICK ECONOMIC SUMMARY
PARAMETERS 10
* LIFE YRS   INFLATION   DISCOUNT   $/SYSTEM   DOWN PAYMENT
   NUMYRS     INFRATE    DISRATE    SYSCOST      DOWNPAY
* LEASE   OANDM   TAX BRACKET   DEPYRS  TAX CREDIT
  LEASE   OANDM    TAXBRACK     DEPYRS  TAXCREDIT
INPUTS 7
*  $ENERGY   $DEMAND   $POLLUTION  DELAY VALUE   SUBSIDY CREDIT
     9,3       9,6         9,4     DELAYVAL      SUBSDYCRDT
* NUMSYS  RETAINVAL
   9,5    RETAINVAL
 5.0  1.0  3.0  1.0  1.0  1.0  1.0
*OUTPUTS:  1)PRESENT WORTH OF INVESTMENT 2)LEVELIZED COST 3)RATE OF RETURN
*          4) LEVELIZED DEMAND
************
** OUTPUT **
************
UNIT 25 TYPE 25   PLOTTING PRINTER
PARAMETERS 4
* DT   T_ON    T_OFF   LU   UNITS
  1    START   STOP    11     1
INPUTS 9
* PRESENT WORTH  LEVELSAV ROR   NUMYRS  INFRATE  DISRATE
      71,1         71,2   71,3  NUMYRS  INFRATE  DISRATE
*SYSCOST  DOWNPAY  LEASE
 SYSCOST  DOWNPAY  LEAS
 PRESWRTH LEVSAV ROR NUMYRS INFRATE DISRATE SYSCOST DWNPAY LEASE
*   $        $    %   YRS     NONE   NONE      $       $   $/mo

UNIT 26 TYPE 25   OUTPUT PRINTER
PARAMETERS 5
* DT   T_ON    T_OFF   LU   UNITS
  1    STOP    STOP    12     1
```

```
INPUTS 3
* PRESENT WORTH  LEVELIZED COST   RATE OF RETURN
      71,1           71,2             71,3
    PRESWRTH       LEVELCOST          ROR
       $               $               %


END
```

APPENDIX C

FORTRAN Programs

TYPE 71: Energy, Emission and Demand Analysis

TYPE 72: Marginal Plant Predictor

TYPE 88: Quick Economic Summary

TYPE 89: Economic Summary

TRNOUT: Formatted Output Program

TYPE 71: Energy, Emission and Demand Analysis

```
      subroutine type71 (time,xin,out,t,dtdt,par,info,icntrl,*)

      implicit none

*  Standard TRNSYS declarations
      COMMON /SIM/ TIME0,TFINAL,DELT,IWARN
      double precision xin,out
      real time,t,dtdt,par,tfinal,time0,delt,iwarn
      integer info,icntrl
      dimension xin(5),out(23),t(1),dtdt(1),par(20),info(15)

*  Type input and parameter variables
      double precision elecdmnd,soldmnd,load,systems,plnt
      integer solmode,lu
      double precision CO2worth,SO2worth,NOXworth,N2Oworth,
     .     PARTSworth,CH4worth,HGworth,NUKEworth,dmndworth,
     .     trnsloss,distloss,reservemar,trnsworth,distworth

*  Loop and external file variables
      double precision dum1,opcost,CO2mass,SO2mass,NOXmass,N2Omass,
     .     PARTSmass,CH4mass,HGmass,NUKEmass
      integer i,j,numplants,order,dum,hrtime,runtime
      character*4 marplant(1000)
      dimension opcost(1000),CO2mass(1000),SO2mass(1000),NOXmass(1000),
     .     N2Omass(1000),PARTSmass(1000),CH4mass(1000),HGmass(1000),
     .     NUKEmass(1000)

*  Energy calculation variables
      double precision enred_g,enred_c,ensavings,TDloss


*  Emission calculation variables
      double precision pollsavings,
     .     CO2red,SO2red,NOXred,N2Ored,PARTSred,CH4red,HGred,NUKEred,
     .     CO2val,SO2val,NOXval,N2Oval,PARTSval,CH4val,HGval,NUKEval

*  Demand/Reliabilty calculation variables
      integer numpeaks,dmndmode,peakhour
      double precision marEUE,peakload,CCIref,CCIoption,dmndred,
     .     dmndsavings,deldmnd,wgtdenred,annwgtdenred,nominalcap,
     .     currentcap,trnsred,distred,deltrns,deldist,CRR
      dimension peakload(8760),peakhour(8760),deldmnd(8760),
     .      deltrns(8760),deldist(8760)


************************************************************************
************************************************************************
      call typeck(1,info,5,20,0)

      hrtime = int(time+.001)
```

```
      runtime = int(tfinal+.001)

      elecdmnd = xin(1)
      soldmnd = xin(2)
      load = xin(3)
      plnt = int(xin(4)+.001)      !***** identify marginal plant
      marEUE = xin(5)

      systems =  par(1)
      CO2worth = par(2)
      SO2worth = par(3)
      NOXworth = par(4)
      N2Oworth = par(5)
      PARTSworth = par(6)
      CH4worth = par(7)
      HGworth = par(8)
      NUKEworth = par(9)
      reservemar = par(10)
      dmndworth = par(11)
      trnsworth = par(12)
      distworth = par(13)
      dmndmode = int(par(14)+.001)
      numpeaks = int(par(15)+.001)
      CCIref = par(16)
      trnsloss = par(17)
      distloss = par(18)
      solmode = int(par(19)+.001)
      lu = int(par(20)+.001)

      info(6) = 23   !number of outputs
      info(9) = 3    !call routine at the end of each timestep
************************************************************************


************************************************************************
*  Read in the plant data
      if (info(7) .eq. -1) then
        read(lu,*) numplants
        do i=1,numplants
           read(lu,*) dum,marplant(i),dum1,dum,dum,dum,dum,
     .           dum,dum,dum,dum,dum,dum1,dum1,dum1,dum1,dum1,
     .           dum1,dum1,dum1,dum1,opcost(i),CO2mass(i),SO2mass(i),
     .           NOXmass(i),N2Omass(i),PARTSmass(i),CH4mass(i),
     .           HGmass(i),NUKEmass(i)
        enddo
         nominalcap = 0.0     !nominal capacity of the option
      endif
************************************************************************


************************************************************************
*  Energy reduction
*   ** Note: g -> at generation level
*            c -> at customer level
```

```
      TDloss = (1-trnsloss)*(1-distloss)

      if (solmode .eq. 1) then         !***  option reduces electric demand
        enred_g =(elecdmnd-soldmnd)*systems/TDloss
        enred_c = (elecdmnd-soldmnd)*systems
        ensavings = enred_g*opcost(plnt)
         currentcap = elecdmnd*systems
      elseif (solmode .eq. 2) then     !***  option generates electricity
        enred_g = soldmnd*systems/TDloss
         enred_c = soldmnd*systems
        ensavings = enred_g*opcost(plnt)
         currentcap = soldmnd*systems
      else
        print*, 'ERROR, SOLAR MODE NOT SPECIFIED CORRECTLY'
      endif
      if (currentcap .gt. nominalcap) then
            nominalcap = currentcap
      endif
************************************************************************


************************************************************************
*  Pollution reduction
*  Convert pollution savings from kWh to MWh
      CO2red = enred_g/1000 * CO2mass(plnt)
      CO2val = CO2red * CO2worth
      SO2red = enred_g/1000 * SO2mass(plnt)
      SO2val = SO2red * SO2worth
      NOXred = enred_g/1000 * NOXmass(plnt)
      NOXval = NOXred * NOXworth
      N2Ored = enred_g/1000 * N2Omass(plnt)
      N2Oval = N2Ored * N2Oworth
      PARTSred = enred_g/1000 * PARTSmass(plnt)
      PARTSval = PARTSred * PARTSworth
      CH4red = enred_g/1000 * CH4mass(plnt)
      CH4val = CH4red * CH4worth
      HGred = enred_g/1000 * HGmass(plnt)
      HGval = HGred * HGworth
      NUKEred = enred_g/1000 * NUKEmass(plnt)
      NUKEval = NUKEred * NUKEworth
      pollsavings = CO2val+SO2val+N2Oval+NOXval+PARTSval+CH4val+HGval
     .              + NUKEval
************************************************************************

************************************************************************
*  Demand/Reliablility calculations:
*     - Mode 1: Demand based on a given number of peak hours
*     - Mode 2: System reliability based on the whole year

*** Mode 1 - Demand calculations ***
      if (dmndmode .eq. 1) then
        if (info(7) .eq. -1) then
           call intzero(peakhour,numpeaks)
           call realzero(peakload,numpeaks)
           call realzero(deldmnd,numpeaks)
```

```
          dmndred = 0.0
           trnsred = 0.0
           distred = 0.0
          dmndsavings = 0.0
           CCIoption = 0.0
       endif
       if (load .gt. peakload(numpeaks)) then
          peakload(numpeaks) = load
          peakhour(numpeaks) = hrtime
          deldmnd(numpeaks) = enred_g*(1+reservemar)
           deltrns(numpeaks) = enred_c/(1-distloss)
           deldist(numpeaks) = enred_c
          call sort(peakload,peakhour,deldmnd,deltrns,deldist,numpeaks
     .               )
       endif
       if (hrtime .eq. runtime) then
          do i=1,numpeaks
             dmndred = dmndred+deldmnd(i)/numpeaks
              trnsred = trnsred+deltrns(i)/numpeaks
              distred = distred+deldist(i)/numpeaks
          enddo
           dmndsavings = dmndred*dmndworth + trnsred*trnsworth
     .                   + distred*distworth
           !** average impact at customer level, not really a CCI
           !** define as energy reduction ratio (CRR)
           CRR = dmndred*TDloss/(1+reservemar)/nominalcap
           CCIoption = CRR
       endif
****  end mode1  ******

*** Mode 2 - Reliability calculations
      elseif (dmndmode .eq. 2) then
       if (info(7) .eq. -1) then
          peakload(1) = 0.0
          dmndsavings = 0.0
           dmndred = 0.0
           trnsred = 0.0
           distred = 0.0
          annwgtdenred = 0.0   !annual weighted energy reduction
       endif
        if (load .gt. peakload(1)) then
          peakload(1) = load
          peakhour(1) = hrtime
          deldmnd(1) = enred_g*(1+reservemar)
           deltrns(1) = enred_c/(1-distloss)
           deldist(1) = enred_c
       endif
        wgtdenred = enred_c*marEUE      !hourly weighted energy reduction
       annwgtdenred = annwgtdenred+wgtdenred
        if (hrtime .eq. runtime) then
           CCIoption = annwgtdenred/nominalcap
          dmndred = CCIoption/CCIref*nominalcap*(1+reservemar)
     .                   /TDloss
           trnsred = CCIoption/CCIref*nominalcap/(1-distloss)
           distred = CCIoption/CCIref*nominalcap
```

```
            dmndsavings = dmndred*dmndworth + trnsred*trnsworth +
     .                      distred*distworth
        endif
****  end mode2  ******

*** Error message if not mode 1 or 2
      else
        print*, 'ERROR, DEMAND MODE NOT SPECIFIED CORRECTLY IN TYPE 71'
      endif
************************************************************************


************************************************************************
      out(1) = enred_g
      out(2) = ensavings

      out(3) = CO2red
      out(4) = CO2val
      out(5) = SO2red
      out(6) = SO2val
      out(7) = NOXred
      out(8) = NOXval
      out(9) = N2Ored
      out(10) = N2Oval
      out(11) = PARTSred
      out(12) = PARTSval
      out(13) = CH4red
      out(14) = CH4val
      out(15) = HGred
      out(16) = HGval
      out(17) = NUKEred
      out(18) = NUKEval
      out(19) = pollsavings

      out(20) = dmndred
      out(21) = dmndsavings
      out(22) = deldmnd(1)
      out(23) = CCIoption
************************************************************************

************************************************************************
      return 1
      end
************************************************************************

************************************************************************
      subroutine realzero(peak,numpeaks)
      integer numpeaks,i
      double precision peak
      dimension peak(8760)

      do i = 1,numpeaks
        peak(i) = 0.0
      enddo
```

```
      return
      end
************************************************************************


************************************************************************
      subroutine intzero(peak,numpeaks)
      integer numpeaks,peak,i
      dimension peak(8760)

      do i = 1,numpeaks
        peak(i) = 0
      enddo

      return
      end
************************************************************************


************************************************************************
      subroutine sort(peakload,peakhour,deldmnd,deltrns,deldist,numpeaks
     .               )
      integer peakhour,numpeaks,i
      double precision peakload,deldmnd,deltrns,deldist
      dimension peakhour(8760),peakload(8760),deldmnd(8760),
     .          deltrns(8760),deldist(8760)

      do i=1,numpeaks-1
        ptr = i
        first = i+1
        do j=first,numpeaks
           if (peakload(j) .gt. peakload(ptr)) then
              ptr = j
           endif
        enddo
        call realswap(peakload(i),peakload(ptr))
        call intswap(peakhour(i),peakhour(ptr))
        call realswap(deldmnd(i),deldmnd(ptr))
         call realswap(deltrns(i),deltrns(ptr))
         call realswap(deldist(i),deldist(ptr))
      enddo

      return
      end
************************************************************************

************************************************************************
      subroutine realswap(original,new)
      double precision original,new,hold

      hold = original
      original = new
      new = hold

      return
```

```
      end
************************************************************************

************************************************************************
      subroutine intswap(original,new)
      integer original,new,hold

      hold = original
      original = new
      new = hold

      return
      end
************************************************************************
```

TYPE 72: Marginal Plant Predictor

```
      subroutine type72 (time,xin,out,t,dtdt,par,info,icntrl,*)

      implicit none

******************************
**  MARGINAL PLANT PREDICTOR **
******************************

*  Standard TRNSYS declarations
      double precision xin,out
      real time,t,dtdt,par
      integer info,icntrl
      dimension xin(2),out(5),t(1),dtdt(1),par(1),info(15)

*  TYPE specific variable declarations
      integer i,numplants,dmonth1,dday1,umonth1,uday1,dmonth2,dday2,
     .     umonth2,uday2,dwnhrs,outhrs,outtime,simtime,LU,plnt,j,
     .     down1,up1,down2,up2
      double precision cap,fullout,partout1,partcap1,partout2,partcap2,
     .     partout3,partcap3,partout4,partcap4,dum,foacap,fsoacap,
     .     foafact,fsoafact,load,totcap,marEUE,marcost,opcost
      logical plantfind
      character plant*10
      dimension plant(5000),cap(5000),dmonth1(5000),dday1(5000),
     .     umonth1(5000),uday1(5000),dmonth2(5000),dday2(5000),
     .     umonth2(5000),uday2(5000),fullout(5000),partout1(5000),
     .     partcap1(5000),partout2(5000),partcap2(5000),partout3(5000),
     .     partcap3(5000),partout4(5000),partcap4(5000),dwnhrs(5000),
     .     foacap(5000),fsoacap(5000),outhrs(5000),down1(5000),
     .     up1(5000),down2(5000),up2(5000),opcost(5000)
************************************************************************

************************************************************************
      call typeck(1,info,2,1,0)

      simtime = int(time+.001)

      load = xin(1)
      marEUE = xin(2)

      LU = int(par(1)+.001)

      info(6) = 3   !number of outputs
      info(9) = 3   !call routine at end of each timestep
************************************************************************

************************************************************************
      if (info(7) .eq. -1) then
         read(LU,*) numplants
         do i = 1,numplants
            read(LU,*) dum,plant(i),cap(i),dmonth1(i),dday1(i),
     .           umonth1(i),uday1(i),dmonth2(i),dday2(i),umonth2(i),
```

```
     .           uday2(i),dwnhrs(i),fullout(i),partout1(i),partcap1(i),
     .           partout2(i),partcap2(i),partout3(i),partcap3(i),
     .           partout4(i),partcap4(i),opcost(i),dum,dum,dum,dum,dum,
     .           dum,dum,dum

            fullout(i) = fullout(i)/100
            partout1(i) = partout1(i)/100
            partout2(i) = partout2(i)/100
            partout3(i) = partout3(i)/100
            partout4(i) = partout4(i)/100

            down1(i) = outtime(dmonth1(i),dday1(i))
            up1(i) = outtime(umonth1(i),uday1(i))
            down2(i) = outtime(dmonth2(i),dday2(i))
            up2(i) = outtime(umonth2(i),uday2(i))
            dwnhrs(i) = dwnhrs(i)*168                !scheduled outage hours
            outhrs(i) = up1(i)-down1(i)+up2(i)-down2(i)  !est. outage period

            foafact = (1-fullout(i) - (partcap1(i)*partout1(i)+
     .           partcap2(i)*partout2(i)+partcap3(i)*partout3(i)+
     .           partcap4(i)*partout4(i))/cap(i))
            foacap(i) = cap(i)*foafact

            if (dwnhrs(i) .le. outhrs(i)) then
               if (outhrs(i) .eq. 0) then
                  fsoafact = 1.0
               else
                  fsoafact = 1.0 - real(dwnhrs(i))/real(outhrs(i))
               endif
            else
               fsoafact = 1.0
               print*, 'ERROR, ACTUAL OUTAGE PERIOD EXCEEDS SCHEDULED OU
     .TAGE PERIOD FOR PLANT ',i,', ',plant(i)
               print*
            endif
            fsoacap(i) = fsoafact*foacap(i)
         enddo
      endif
************************************************************************

************************************************************************
      plantfind = .false.
      totcap = 0
      do j = 1,numplants
         if (((simtime.ge.down1(j)).and.(simtime.lt.up1(j))) .or.
     .        ((simtime.ge.down2(j)).and.(simtime.lt.up2(j)))) then
            totcap = totcap + fsoacap(j)
         else
            totcap = totcap + foacap(j)
         endif
         if ((totcap .gt. load) .and. (.not. plantfind)) then   !find marginal
plant
            plantfind = .true.
            plnt = j
            marcost = opcost(j)
```

```
         endif
         if ((.not.plantfind).and.(j.eq.numplants)) then
            print*, 'ERROR.  MARGINAL PLANT NOT FOUND OR LOAD EXCEEDS TO
     .TAL CAPACITY AT HOUR ',simtime,'.  THE LAST PLANT WILL BE ASSUMED
     .THE MARGIN.'
            plnt = j
            goto 20
         endif
      enddo

 20   continue


***********************************************************************

***********************************************************************

      out(1) = load
      out(2) = plnt
      out(3) = marEUE
      out(4) = marcost
      out(5) = totcap

      return 1
      end
***********************************************************************

***********************************************************************
      function outtime(month,day)
      implicit none
      integer outtime,month,day

      if (month .eq. 0) then
         outtime = 0
      elseif (month .eq. 1) then
         outtime = (day-1)*24 + 1
      elseif (month .eq. 2) then
         outtime = (31+day-1)*24 + 1
      elseif (month .eq. 3) then
         outtime = (59+day-1)*24 + 1
      elseif (month .eq. 4) then
         outtime = (90+day-1)*24 + 1
      elseif (month .eq. 5) then
         outtime = (120+day-1)*24 + 1
      elseif (month .eq. 6) then
         outtime = (151+day-1)*24 + 1
      elseif (month .eq. 7) then
         outtime = (181+day-1)*24 + 1
      elseif (month .eq. 8) then
         outtime = (212+day-1)*24 + 1
      elseif (month .eq. 9) then
         outtime = (243+day-1)*24 + 1
      elseif (month .eq. 10) then
         outtime = (273+day-1)*24  + 1
      elseif (month .eq. 11) then
```

```
      outtime = (304+day-1)*24 + 1
   elseif (month .eq. 12) then
      outtime = (334+day-1)*24 + 1
   endif

   end
```

TYPE 88: Quick Econonomic Summary

```
      subroutine type88 (time,xin,out,t,dtdt,par,info,icntrl,*)

****************************
** QUICK ECONOMIC ANALYSIS **
****************************

      implicit none

*  Standard TRNSYS declarations
      COMMON /SIM/ TIME0,TFINAL,DELT,IWARN
      double precision xin,out
      real time,t,dtdt,par,tfinal,time0,delt,iwarn
      integer info,icntrl
      dimension xin(7),out(3),t(1),dtdt(1),par(10),info(15)

*  Economic variable declarations
      double precision PresWorth,investment,delay,retention,inf,dis,
     .         energy,demand,pollution,oandm,syscost,PWF,levelcost,
     .         taxbracket,depreciation,maxdif,ror,PW,A,B,C,D,dPW,
     .         dPWF_d,downpay,lease,taxcredit,subsidy,numsys,numyrs,
     .         depyrs
      integer lc,found,runtime,simtime
************************************************************************

************************************************************************
      call typeck(1,info,7,10,0)

      simtime = int(time+.001)
      runtime = int(tfinal+.001)

      energy = xin(1)
      demand = xin(2)
      pollution = xin(3)
      delay = xin(4)
      subsidy = xin(5)
      numsys = xin(6)
      retention = xin(7)


      numyrs = par(1)
      inf = par(2)
      dis = par(3)
      syscost = par(4)
      downpay = par(5)
      lease = par(6)
      oandm = par(7)
      taxbracket = par(8)
      depyrs = par(9)
      taxcredit = par(10)

      info(6) = 3    !number of outputs
      info(9) = 3    !call routine at the end of each timestep
```

```
************************************************************************

************************************************************************
      if (simtime .eq. runtime) then
        investment = numsys*syscost
        downpay = downpay*numsys
        lease = lease*numsys
        oandm = oandm*numsys
        taxcredit = taxcredit*investment
        if (depyrs .eq. 0) then
           depreciation = 0
        else
           depreciation = investment/depyrs*taxbracket
        endif
        A = -investment+delay+retention+downpay+taxcredit+demand
        B = energy+pollution+subsidy-oandm
        C = depreciation
         D = lease
        PresWorth = A + B*PWF(numyrs,inf,dis) + C*PWF(depyrs,0.d0,dis)
     .               + D*PWF(numyrs,0.d0,dis)
        levelcost = PresWorth/PWF(numyrs,0.d0,dis)

C  Calculate the Rate of Return (Return on Investment)
           maxdif = .0001
           lc = 0         !intitialize loop conter
           found =0       !if found = 1 -> the solution has converged
           ror = dis      !initial guess value for rate of return

 10         lc = lc+1
           PW = A + B*PWF(numyrs,inf,ror) + C*PWF(depyrs,0.d0,ror)
     .           + D*PWF(numyrs,0.d0,ror)
           if (abs(PW) .lt. maxdif) then
              found = 1
           else
              dPW =B*dPWF_d(numyrs,inf,ror) + C*dPWF_d(depyrs,0.d0,ror)
     .               + D*dPWF_d(numyrs,0.d0,ror)
              ror = -PW/(dPW+.00001) + ror
              if (lc .eq. 10000) then
           print*, 'ror has not converged'
           goto 20
              endif
           endif
           if (found .eq. 0) goto 10
************************************************************************
 20      continue
        out(1) = PresWorth
        out(2) = levelcost
        out(3) = ror*100
      endif

      return 1
      end
************************************************************************
```

TYPE 89: Economic Summary

```
      subroutine type89 (time,xin,out,t,dtdt,par,info,icntrl,*)

***********************
** ECONOMIC ANALYSIS **
***********************

      implicit none

*  Standard TRNSYS declarations
      COMMON /SIM/ TIME0,TFINAL,DELT,IWARN
      double precision xin,out
      real time,t,dtdt,par,tfinal,time0,delt,iwarn
      integer info,icntrl
      dimension xin(4),out(16),t(1),dtdt(1),par(13),info(15)

*  Economic variable declarations
      double precision PresWorth,investment,delay,retention,inf,dis,
     .         energy,demand,pollution,oandm,syscost,PWF,levelcost,
     .         taxbracket,depreciation,maxdif,ror,PW,A,B,C,D,dPW,
     .         dPWF_d,downpay,lease,taxcredit,subsidy,DmndWorth,numsys,
     .         numyrs,depyrs,energyPW,pollutionPW,oandmPW,leasePW,
     .         subsidyPW,depreciationPW
      integer lc,found,runtime,simtime
************************************************************************

************************************************************************
      call typeck(1,info,5,12,0)

      simtime = int(time+.001)
      runtime = int(tfinal+.001)

      energy = xin(1)
      demand = xin(2)
      pollution = xin(3)
      delay = xin(4)
      subsidy = xin(5)

      numyrs = par(1)
      inf = par(2)
      dis = par(3)
      numsys = par(4)
      syscost = par(5)
      downpay = par(6)
      lease = par(7)
      oandm = par(8)
      retention = par(9)
      taxbracket = par(10)
      depyrs = par(11)
      taxcredit = par(12)

      info(6) = 3    !number of outputs
```

```
      info(9) = 3    !call routine at the end of each timestep
************************************************************************

************************************************************************
      if (simtime .eq. runtime) then
        investment = numsys*syscost
        downpay = downpay*numsys
        lease = lease*numsys
        oandm = oandm*numsys
        taxcredit = taxcredit*investment
        if (depyrs .eq. 0) then
           depreciation = 0
        else
           depreciation = investment/depyrs*taxbracket
        endif
        A = -investment+delay+retention+downpay+taxcredit+demand
        B = energy+pollution+subsidy-oandm
           energyPW = energy*PWF(numyrs,inf,dis)
             pollutionPW = pollution*PWF(numyrs,inf,dis)
             subsidyPW = subsidy*PWF(numyrs,inf,dis)
             oandmPW = oandm*PWF(numyrs,inf,dis)
        C = depreciation
             depreciationPW = C*PWF(depyrs,0.d0,dis)
         D = lease
             leasePW = D*PWF(numyrs,0.d0,dis)
        PresWorth = A + B*PWF(numyrs,inf,dis) + C*PWF(depyrs,0.d0,dis)
     .               + D*PWF(numyrs,0.d0,dis)
        levelcost = PresWorth/PWF(numyrs,0.d0,dis)
        DmndWorth = demand/PWF(numyrs,inf,dis)


C  Calculate the Rate of Return (Return on Investment)
           maxdif = .0001
           lc = 0         !intitialize loop conter
           found = 0      !if found = 1 -> the solution has converged
           ror = dis      !initial guess value for rate of return
 10          lc = lc+1
           PW = A + B*PWF(numyrs,inf,ror) + C*PWF(depyrs,0.d0,ror)
     .           + D*PWF(numyrs,0.d0,ror)
           if (abs(PW) .lt. maxdif) then
              found = 1
           else
              dPW = B*dPWF_d(numyrs,inf,ror) + C*dPWF_d(depyrs,0.d0,ror)
     .                + D*dPWF_d(numyrs,0.d0,ror)
              ror = -PW/dPW + ror
              if (lc .eq. 10000) then
           print*, 'ror has not converged'
           goto 20
              endif
           endif
           if (found .eq. 0) goto 10
************************************************************************

 20      continue
```

```
        out(1) = PresWorth
        out(2) = levelcost
        out(3) = ror*100
        out(4) = DmndWorth
        out(5) = investment
        out(6) = delay
        out(7) = retention
        out(8) = downpay
        out(9) = taxcredit
        out(10) = demand
        out(11) = energyPW
        out(12) = pollutionPw
         out(13) = subsidyPW
        out(14) = oandmPW
         out(15) = depreciationPW
         out(16) = leasePW

      endif

      return 1
      end
************************************************************************

************************************************************************
      function PWF(N,i,d)
      double precision i,d,N,PWF

      if (i.eq.d) then
        PWF = N/(1+i)
      else
        PWF = (1-((1+i)/(1+d))**N)/(d-i)
      endif

      return
      end
************************************************************************

************************************************************************
      function dPWF_d(N,i,d)
      double precision i,d,N,dPWF_d,PWF

      if (i.eq.d) then
        dPWF_d = -N/(d+1)**2
      else
        dPWF_d = (N/(1+d)*((1+i)/(1+d))**N-PWF(N,i,d))/(d-i)
      endif

      return
      end
************************************************************************
```

TRNOUT: Formatted Output Program

```
      program trnout

      implicit none

      real enred,ensav,CO2red,CO2val,SO2red,SO2val,N2Ored,N2Oval,
     .     NOXred,NOXval,PARTSred,PARTSval,CH4red,CH4val,HGred,HGval,
     .     NUKEred,NUKEval,pollsav,dmndred,dmndsav,PresWorth,LevelCost,
     .     ROR,time,systems,CCI,sumrate,winrate,enredmo,sfmo,totsav,
     .     dmode,soldmdmo,elcdmdmo,custsav,SysCost,delay,retention,
     .     down,taxcr,PWdmndsav,PWensav,PWemissav,PWsubsidy,PWoandm,
     .     PWdepr,PWleas
      integer sys,dmndmode,i
      dimension enredmo(13),sfmo(13),soldmdmo(13),elcdmdmo(13),
     .          custsav(13)

      open(unit=10,file='c:\ EUSESIA\ utility.out',status='unknown')
      open(unit=11,file='c:\ EUSESIA\ util1.dat',status='unknown')
      open(unit=12,file='c:\ EUSESIA\ util2.dat',status='unknown')
      open(unit=13,file='c:\ EUSESIA\ util3.dat',status='unknown')
      open(unit=14,file='c:\ EUSESIA\ util4.dat',status='unknown')
      open(unit=15,file='c:\ EUSESIA\ util6.dat',status='unknown')
      open(unit=16,file='c:\ EUSESIA\ util7.dat',status='unknown')

C Read past line containg lable from TYPE 25 printer
      read(11,*)
      read(12,*)
      read(13,*)
      read(14,*)
      read(15,*)
      read(16,*)

      read(11,*) time,enred,ensav,CO2red,CO2val,SO2red,SO2val,NOXred,
     .           NOXval,N2Ored,N2Oval
      read(12,*) time,partsred,partsval,CH4red,CH4val,HGred,HGval,
     .           NUKEred,NUKEval,pollsav,systems
      read(13,*) time,dmndred,dmndsav,CCI,PresWorth,LevelCost,ROR,
     .           sumrate,winrate,dmode,SysCost

C read first line of data in this file
      read(14,*)
      elcdmdmo(13) = 0
      soldmdmo(13) = 0
      enredmo(13) = 0
      custsav(13) = 0

      do i = 1,12
        read(14,*) time,soldmdmo(i),elcdmdmo(i)
        enredmo(i) = elcdmdmo(i) - soldmdmo(i)
        soldmdmo(13) = soldmdmo(13) + soldmdmo(i)
        elcdmdmo(13) = elcdmdmo(13) + elcdmdmo(i)
        enredmo(13) = enredmo(13) + enredmo(i)
```

```
      enddo

      read(15,*) time,delay,retention,down,taxcr,PWdmndsav,PWensav,
     .           PWemissav,PWsubsidy,PWoandm,PWdepr

      read(16,*) time,PWleas

      if (elcdmdmo(13) .ne. 0) then
        do i=1,5
           custsav(i) = enredmo(i)*winrate
        enddo
        do i=6,9
           custsav(i) = enredmo(i)*sumrate
        enddo
        do i=10,12
           custsav(i) = enredmo(i)*winrate
        enddo
        do i=1,13
           sfmo(i) = enredmo(i)/elcdmdmo(i)
        enddo
        do i=1,12
           custsav(13) = custsav(13) + custsav(i)
        enddo
      else
        do i=1,5
           custsav(i) = soldmdmo(i)*winrate
        enddo
        do i=6,9
           custsav(i) = soldmdmo(i)*sumrate
        enddo
        do i=10,12
           custsav(i) = soldmdmo(i)*winrate
        enddo
        do i=1,12
           custsav(13) = custsav(13) + custsav(i)
        enddo
      endif

      totsav = ensav+pollsav+dmndsav
      sys = int(systems+.001)
      dmndmode = int(dmode+.001)
      SysCost = SysCost*real(sys)


      write(10,*)
      write(10,*) '              Electric Utility Solar Energy System Im
     .pact Analysis:'
      write(10,*)
      write(10,*) '          Impact of a Large Scale Implemention of a S
     .olar Energy System'
      write(10,*) '                            on an Electric Utility'
      write(10,*)
      write(10,*) '******  Energy and Environmental Impact Summary for t
     .he First Year  ******'
      write(10,200) sys
```

```
      write(10,*)
      write(10,*) '            Energy Reduction (kWh)     Energy Savings
     . ($)'
      write(10,100) enred,ensav
      write(10,*)
      write(10,*) '            Emission Reduction (lbm)   Emission Savin
     .gs ($)     '
      write(10,101) CO2red,CO2val
      write(10,102) SO2red,SO2val
      write(10,103) NOXred,NOXval
      write(10,104) N2Ored,N2Oval
      write(10,105) partsred,partsval
      write(10,106) CH4red,CH4val
      write(10,107) HGred,HGval
      write(10,108) NUKEred,NUKEval
      write(10,109) pollsav
      write(10,*)
      write(10,*) '            Demand Reduction (kW)      Demand Savings
     . ($)       '
      write(10,110) dmndred,dmndsav
      write(10,*)
      write(10,*) '                                       Total Savings
     .($) '
      write(10,111) totsav
      write(10,*)
      write(10,*) '******  Economic Analysis Summary  *****************
     .************************'
      write(10,*)
      write(10,300) SysCost
      write(10,301) PWoandm
      write(10,302) PWensav
      write(10,303) PWemissav
      write(10,304) PWdmndsav
      write(10,305) PWdepr
      write(10,306) down
      write(10,307) PWleas
      write(10,308) taxcr
      write(10,309) PWsubsidy
      write(10,310) retention
      write(10,311) delay
      write(10,*)
      write(10,312) PresWorth
      write(10,313) LevelCost
      write(10,314) ROR
      write(10,*)
      write(10,*) '******  System Performance Summary and Customer Savin
     .gs  *******************'
      write(10,*) ' Results based on average system performance'
      write(10,*)

      IF (INT(elcdmdmo(13)-.001) .ne. 0) THEN
      write(10,*) '          Elc (kWh)   Sol (kWh)   Del (kWh)    SF
     .    Savings ($)  '
      write(10,401) elcdmdmo(1),soldmdmo(1),enredmo(1),sfmo(1),
     .              custsav(1)
```

```
      write(10,402) elcdmdmo(2),soldmdmo(2),enredmo(2),sfmo(2),
     .              custsav(2)
      write(10,403) elcdmdmo(3),soldmdmo(3),enredmo(3),sfmo(3),
     .              custsav(3)
      write(10,404) elcdmdmo(4),soldmdmo(4),enredmo(4),sfmo(4),
     .              custsav(4)
      write(10,405) elcdmdmo(5),soldmdmo(5),enredmo(5),sfmo(5),
     .              custsav(5)
      write(10,406) elcdmdmo(6),soldmdmo(6),enredmo(6),sfmo(6),
     .              custsav(6)
      write(10,407) elcdmdmo(7),soldmdmo(7),enredmo(7),sfmo(7),
     .              custsav(7)
      write(10,408) elcdmdmo(8),soldmdmo(8),enredmo(8),sfmo(8),
     .              custsav(8)
      write(10,409) elcdmdmo(9),soldmdmo(9),enredmo(9),sfmo(9),
     .              custsav(9)
      write(10,410) elcdmdmo(10),soldmdmo(10),enredmo(10),sfmo(10),
     .              custsav(10)
      write(10,411) elcdmdmo(11),soldmdmo(11),enredmo(11),sfmo(11),
     .              custsav(11)
      write(10,412) elcdmdmo(12),soldmdmo(12),enredmo(12),sfmo(12),
     .              custsav(12)
      write(10,*)
      write(10,413) elcdmdmo(13),soldmdmo(13),enredmo(13),sfmo(13),
     .              custsav(13)
      write(10,*)

      ELSE
      write(10,*) '          ElcGen (kWh)   Savings ($)  '
      write(10,501) soldmdmo(1),custsav(1)
      write(10,502) soldmdmo(2),custsav(2)
      write(10,503) soldmdmo(3),custsav(3)
      write(10,504) soldmdmo(4),custsav(4)
      write(10,505) soldmdmo(4),custsav(5)
      write(10,506) soldmdmo(6),custsav(6)
      write(10,507) soldmdmo(7),custsav(7)
      write(10,508) soldmdmo(8),custsav(8)
      write(10,509) soldmdmo(9),custsav(9)
      write(10,510) soldmdmo(10),custsav(10)
      write(10,511) soldmdmo(11),custsav(11)
      write(10,512) soldmdmo(12),custsav(12)
      write(10,*)
      write(10,513) soldmdmo(13),custsav(13)
      ENDIF

      write(10,*)
      IF (dmndmode .eq. 1) THEN
        write(10,*) ' Option Capacity Reduction Ratio'
        write(10,112)  CCI
      ELSE
        write(10,*) ' Option Capacity Contribution Index '
        write(10,112)  CCI
      ENDIF
```

```
100  FORMAT('             ',F12.0,'              ',F12.0,'
    .')
101  FORMAT('     CO2     ',F12.0,'              ',F12.0,'
    .')
102  FORMAT('     SO2     ',F12.0,'              ',F12.0,'
    .')
103  FORMAT('     NOX     ',F12.0,'              ',F12.0,'
    .')
104  FORMAT('     N2O     ',F12.0,'              ',F12.0,'
    .')
105  FORMAT('    Parts    ',F12.0,'              ',F12.0,'
    .')
106  FORMAT('     CH4     ',F12.0,'              ',F12.0,'
    .')
107  FORMAT('      HG     ',F12.0,'              ',F12.0,'
    .')
108  FORMAT('    NUKES    ',F12.0,'              ',F12.0,'
    .')
109  FORMAT('                                       ',F12.0,'
    .  ')
110  FORMAT('             ',F12.0,'              ',F12.0,'
    . ')
111  FORMAT('                                       ',F12.0,'
    .   ')
112  FORMAT('     ',F12.3)

200  FORMAT(' Results based on:',I5,' solar systems')

300  FORMAT('   Present Worth of Investment        - $',F14.0,'  ')
301  FORMAT('   Present Worth of O&M               - $',F14.0,'  ')
302  FORMAT('   Present Worth of Energy Savings      $',F14.0,'  ')
303  FORMAT('   Present Worth of Emission Savings    $',F14.0,'  ')
304  FORMAT('   Present Worth of Demand Savings      $',F14.0,'  ')
305  FORMAT('   Present Worth of Depreciation        $',F14.0,'  ')
306  FORMAT('   Present Worth of Downpayments        $',F14.0,'  ')
307  FORMAT('   Present Worth of Lease Payments      $',F14.0,'  ')
308  FORMAT('   Present Worth of Tax Credit          $',F14.0,'  ')
309  FORMAT('   Present Worth of Energy Subsidy      $',F14.0,'  ')
310  FORMAT('   Present Worth of Customer Retention  $',F14.0,'  ')
311  FORMAT('   Present Worth of Delay Value         $',F14.0,'  ')



312  FORMAT('   Present Worth of Life Cycle Savings  $',F14.0,'  ')
313  FORMAT('   Levelized Savings of Option          $',F14.0,'  ')
314  FORMAT('   Rate of Invstment of Option                ',F6.1,' %
    . ')


401  FORMAT('    JAN    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
    .3,'         ',F6.2,'     ')
402  FORMAT('    FEB    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
    .3,'         ',F6.2,'     ')
403  FORMAT('    MAR    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
    .3,'         ',F6.2,'     ')
```

```
 404  FORMAT('    APR    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 405  FORMAT('    MAY    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 406  FORMAT('    JUN    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 407  FORMAT('    JUL    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 408  FORMAT('    AUG    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 409  FORMAT('    SEP    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 410  FORMAT('    OCT    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 411  FORMAT('    NOV    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 412  FORMAT('    DEC    ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')
 413  FORMAT('    YEAR   ',F6.0,'      ',F6.0,'      ',F6.0,'      ',F4.
     .3,'         ',F6.2,'     ')

 501  FORMAT('    JAN    ',F6.0,'      ',F6.2,'     ')
 502  FORMAT('    FEB    ',F6.0,'      ',F6.2,'     ')
 503  FORMAT('    MAR    ',F6.0,'      ',F6.2,'     ')
 504  FORMAT('    APR    ',F6.0,'      ',F6.2,'     ')
 505  FORMAT('    MAY    ',F6.0,'      ',F6.2,'     ')
 506  FORMAT('    JUN    ',F6.0,'      ',F6.2,'     ')
 507  FORMAT('    JUL    ',F6.0,'      ',F6.2,'     ')
 508  FORMAT('    AUG    ',F6.0,'      ',F6.2,'     ')
 509  FORMAT('    SEP    ',F6.0,'      ',F6.2,'     ')
 510  FORMAT('    OCT    ',F6.0,'      ',F6.2,'     ')
 511  FORMAT('    NOV    ',F6.0,'      ',F6.2,'     ')
 512  FORMAT('    DEC    ',F6.0,'      ',F6.2,'     ')
 513  FORMAT('    YEAR   ',F6.0,'      ',F6.2,'     ')


      close(10)
      close(11)
      close(12)
      close(13)
      close(14)
      close(15)
      close(16)

      return
      end
```