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Research Article

Modeling the Feasibility of Using Solar Thermal Systems for Meeting the Heating Requirements at Corn Ethanol Production Facilities

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While ethanol use as a vehicle fuel has been promoted as a renewable alternative to fossil fuels, current production methods of ethanol from corn feedstock rely heavily on the combustion of nonrenewable fuels such as natural gas. Solar thermal systems can provide a renewable energy source for supplying some of the heat required ethanol production. In this paper, a model to analyze the feasibility of using solar thermal energy to reduce natural gas consumption in ethanol production is described and applied. Sites of current ethanol production facilities are used to provide a realistic analysis of the economic feasibility of using solar thermal energy in the ethanol production process. The results show that it is not reasonable to expect to replace all of the natural gas consumption in the heating processes in ethanol production but that application of solar thermal energy can be applied to a specific subsystem such as the preheating of boiler makeup water. Profitability of systems for replacing a fraction of the natural gas is analyzed. It is found that both location and local natural gas prices are important in determining whether to pursue such a project and that solar thermal systems should have long-term profitability.

1. Introduction

Energy is a global concern. There are limited resources of fossil fuels, and the alternatives are generally expensive, are limited in capacity, or represent technology still in need of development. Growing concerns over global climate change and energy security have led to expanded use of renewable energy sources like fuel ethanol and solar energy. These technologies are expected to grow in capacity to meet rising global energy requirements and to help offset fossil fuel use.

Currently, much of the fuel ethanol in use is derived from corn, and one of the main drawbacks of ethanol derived from corn is the energy required to produce the fuel. While ethanol is considered a renewable fuel, the typical current ethanol production methods represent a nonrenewable process as large amounts of fossil fuels are used in the production process. Increasing the amount of renewable energy used in ethanol production will reduce fossil fuel use, will decrease greenhouse gas emissions, and may ultimately reduce the ethanol plant's energy costs. Solar energy is one form of renewable energy that might be used to reduce the nonrenewable fuel use in the ethanol production.

There are many factors that determine the economic feasibility of a solar energy project. Solar resources vary significantly with location and not every location is an ideal candidate for solar use. The type and size of the equipment influence costs and potential energy savings. The current costs of traditional energy sources play a major role in the financial viability of a solar energy project as well. In this paper we describe and use a model that can be used to evaluate the feasibility of installing a solar thermal array at a corn ethanol plant. The model can be used with plant-specific information to accurately estimate the useful energy produced by a solar array at that location. Cost estimates for the solar energy installation along with recent prices of natural gas are used to find the payback period and cost savings for each project. A wide range of projects can be considered by the same model through the modification of many variables to simulate different conditions for the solar energy, energy prices, and government incentives.

The estimated energy output from the model was verified by comparing results to the experimental data for solar thermal arrays from the Institute for Solar Technology [1]. The model is then used to assess the solar resources and economic feasibility of a solar thermal array at a variety of actual ethanol plant locations in the United States. The locations are chosen to represent a wide range of solar conditions to find the best areas for solar energy systems, while still representing logical locations for the ethanol production facilities. Various inputs are changed to determine their effects on payback period and cost savings. Recent United States federal tax incentives are also considered to determine their financial influence on solar projects.

2. Background

2.1. Ethanol. Ethanol has been used for years as an automotive fuel additive to reduce gasoline consumption, raise the octane level of vehicle fuel, and reduce pollution [2–12] (Reisel et al., 2001). Currently, most of the ethanol produced in the United States comes from corn. While the corn feedstock is renewable, one of the main reasons corn ethanol is not completely renewable is the large amount of energy required to cook and distill the corn feedstock. Over 90% of US facilities use natural gas for process heat [13] and use electricity generated mainly from coal and natural gas. Reducing fossil fuel use in the production of ethanol will make the process more sustainable.

The majority of ethanol plants in the United States are located throughout the Midwest region where corn is most plentiful. This ensures adequate supply and reduces transportation costs between the farm and the ethanol production facility. About 90% of the ethanol plants in the US use the dry mill process to produce ethanol from corn [13]. Therefore, this study focuses on corn ethanol produced from dry mill plants using natural gas for process heat. Another advantage to placing ethanol plants near farmland is the proximity to livestock. The main coproduct of ethanol plants, distillers grains, is sold as an additive to livestock feed. The sale of coproducts for animal feed greatly improves the economics and energy balance of ethanol production.

The ethanol industry has seen rapid growth due to energy, fuel, and pollution regulations. The industry grew to 52.6 billion liters of ethanol produced in 2011 from just 6.1 billion liters in 2000 [14]. This growth was a result of rising gas prices and government subsidies. Some of these incentives for corn ethanol are expiring naturally as the industry matures, but the ethanol market as a whole is expected to expand with tax incentives and energy mandates to accelerate the growth of cellulosic and advanced biofuels [13].

The amount of energy to produce corn ethanol has decreased through numerous efficiency improvements and the use of waste heat. A survey of dry mill corn ethanol plants shows that the average energy and corn requirements to produce ethanol decreased significantly from 2001 to 2008 [15]. In 2001, the average plant used 10,000 kJ of heating, 0.288 kWh of electricity, and 13.4 liters of corn to produce one liter of ethanol. The average plant in 2008 only used 8,040 kJ of heating, 0.195 kWh of electricity, and 12.7 liters of corn to produce that same liter of ethanol. The study included 90 of the 150 operating dry mill plants in 2008 and was a good representation of the industry because it included plants of all ages.

Many ethanol opponents claim ethanol has a negative energy balance [16, 17], but others specifically disprove these claims [18, 19]. Much of the disagreement centers on how energy for by-products is accounted for. Here, however, we are not concerned with whether or not corn ethanol has a positive energy balance. Rather, we are concerned with the large amount of nonrenewable energy that is used in the production of corn ethanol and are investigating the feasibility of using more solar energy to reduce the current nonrenewable energy use. If a renewable energy source such as solar energy is used to produce ethanol, the positive/negative energy balance issue becomes less important.

2.2. Solar Thermal Energy. The use of solar energy for heating is not a new idea, but advancing technologies are making it possible to use solar thermal energy for large-scale applications for numerous end uses [20–31]. Solar thermal collectors work on the general premise of using solar energy to heat a fluid, which can then be used to provide thermal energy. Low-temperature applications (below 120°C) can use nonconcentrating collectors. Higher temperatures can be achieved with concentrating collectors that use reflectors to greatly increase the temperature of the working fluid. Concentrating collectors are generally more expensive and require more space to process the same amount of fluid as nonconcentrating collectors. Since none of the processes in an ethanol plant require fluids above 120°C and most of the ethanol plants are not located in prime concentrating solar regions, only nonconcentrating collectors will be considered for thermal energy production at ethanol plants in this study.

Solar thermal energy is available year round across the United States; however, the overall efficiency of the solar collectors is greatly affected by location. Collector efficiency decreases as the temperature difference between the working fluid and ambient air increases. Efficiency is also negatively affected by decreasing solar insulation, which occurs during the winter months. This means that areas of the United States that have large temperature swings between summer and winter will see enormous differences in energy obtained from a solar thermal system throughout the year. The solar installation will also produce no energy overnight and may not produce energy on particularly overcast or cold days. All of these factors make solar thermal systems better suited for supplemental heat as opposed to the main source of process heat.

The solar thermal resources in the United States are concentrated in the Southwest region of the country, but solar thermal installations have been successful across the country [32]. It is clear that some of the Midwest states may not be ideal locations for solar thermal installations, but that just indicates that each collector will produce less energy as compared to a state in the Southwest. The payback period for a solar thermal installation will likely be longer in the Midwest compared to the Southwest, but both systems will

supply thermal energy with nearly no GHG emissions or fuel consumption.

The two most common types of nonconcentrating solar collectors are flat plate and evacuated tube. They have some notable differences that may make one or the other more suitable for different areas of the country. Flat plate collectors use an absorber plate to transfer solar energy to tubes of fluid that pass through the plate. The only protection from ambient conditions is the air gap between the absorber plate and the protective glass cover and the insulation on the back of the panel. This makes flat plate collectors susceptible to substantial heat loss in cold climates and may freeze if the temperature drops low enough. Evacuated tube collectors are generally less vulnerable to freezing and heat loss because the tubes around the working fluid are evacuated to reduce heat transfer to the ambient air. The advantages of flat plate collectors are that they are less expensive in the United States and have lower maintenance costs. Some of the tubes in an evacuated tube system will eventually lose their vacuum, which will require time and materials to repair.

A study completed by Ayompe et al. [33] compared the performance of a flat plate collector and an evacuated tube collector with a closed glycol system over an entire year in Dublin, Ireland. The overall system performance averaged over the entire year for the flat plate was 37.9%, which was significantly less than the 50.3% efficiency for the evacuated tube system. The collectors themselves had efficiencies of 46.1% and 60.7% for the flat plate and evacuated tube panels, respectively. The total system efficiency was decreased by pipe heat losses, which amounted to about 17% of the total energy collected. It is clear that, even with pipe insulation, there will be significant heat losses in solar thermal arrays. Ireland has low solar resources, but the solar thermal arrays were able to provide hot water for the experiments. The solar resource in Ireland is about 2.7 kWh/m^2/day [34], which is over 30% lower than any of the locations considered for this study.

Solar thermal systems are an effective alternative to burning fossil fuels when heating water. They use very little energy to operate compared to a traditional natural gas or electric heater with nearly 100% reduction in GHG emissions and fossil fuel use. Large-scale water heating systems will be limited by the space available and capital required for the equipment. The long lifespan of the equipment and low maintenance costs should result in low cost energy production for decades.

3. Model Description

A model was created to investigate the viability of installing a solar thermal array to reduce fossil fuel use at various locations of ethanol production facilities in the United States [35]. This model can be used to (a) determine if a reasonable payback period can be achieved at the considered current locations and (b) investigate the feasibility of developing new facilities utilizing solar thermal arrays through using user-entered meteorological and resource data. Focus in this work is on the investigation of current facility locations to determine if retrofitting such facilities is economically feasible. Recent and projected energy prices are used to estimate yearly cost savings and payback periods for modeled solar energy installations.

The basic function of the model is to use input data to estimate realistic energy production of an installed solar array. This spreadsheet-based model uses operator-entered data to estimate yearly energy production, cost savings, and lifetime savings of a given system. The user enters resource data for the location and solar array specifications. These values are used to find the yearly energy production of the solar array. Average gas rates are used to find payback periods and lifetime net savings of the solar installation, which allows for analysis of the location for solar energy suitability.

This model was designed to work with and expand upon the work of Kumar and Reisel [36] in which they developed a model to estimate the energy required to produce corn ethanol at dry mill plants using only natural gas for thermal energy. Their model uses detailed inputs for the various processes required to cook and distill ethanol to determine the required thermal energy inputs. The model used here uses the model developed by Kumar and Reisel [36] to provide the thermal energy requirement for an ethanol facility.

Nameplate ethanol production capacity of a given ethanol plant is the main factor in determining energy use for the facility. This is entered into the model as the production capacity in million liters per year (MLY) of anhydrous ethanol. All values for ethanol will be assumed to be anhydrous ethanol unless otherwise noted. Capacity values are published for all currently operating plants online and in many ethanol publications [37]. Most plants produce between 150 and 400 MLY. Equation (1) estimates the total thermal energy, Q_{Total}, needed for an ethanol plant:

$$Q_{Total} = PC \times Q_{AE}, \tag{1}$$

where PC is the plant capacity in MLY, and Q_{AE} is the heating rate required to produce anhydrous ethanol. The model of Kumar and Reisel calculates Q_{AE} for various plant conditions by adding the total energy to cook (Q_{AE}^{Cook}) and the total energy to distill (Q_{AE}^{D}), per unit anhydrous ethanol:

$$Q_{AE} = Q_{AE}^{Cook} + Q_{AE}^{D}. \tag{2}$$

The value for Q_{AE} can also be found by using averages found from actual operational ethanol plants. A survey of 90 ethanol plants showed that the average dry mill corn ethanol plant used 8,040 kJ/liter-ethanol for plants using natural gas in 2008 [15]. It is not essential that this number exactly matches a particular facility's energy consumption as it is mainly used to determine the percent of the total energy used that the solar installations replace.

The percent shift for the total natural gas heating requirement to solar thermal energy of the ethanol plant is most likely going to be small. Ethanol requires substantial amounts of energy to cook and distill, primarily due to the sheer volume of water and mash that must be heated. Most plants reuse most or all of the process water to take advantage of the residual heat remaining after the ethanol has been distilled out. This means there will be relatively small amounts

of makeup water necessary to replace lost boiler water in the ethanol production process. The average fresh water requirement of a survey of 73 dry mill natural gas plants was 2.72 liters of water per liter of ethanol produced [15]. Aden [38] reports that most of the fresh water used in ethanol plants is makeup water for the boiler and cooling tower due to nearly complete reuse of process water. Approximately 68% of the makeup water goes to the cooling tower and 32% goes to the boiler. The boiler makeup water requirement in liters of water per liter of ethanol (MW_B) is given by

$$MW_B = (MW_{total})(\%W_B), \tag{3}$$

where MW_{total} is the total makeup water requirement (MW_{total}) for the plant and $\%W_B$ is the percentage of makeup water going to the boiler. If an average value of 3-liter-water/liter-ethanol is used for MW_{total}, then the necessary boiler makeup water would be about 0.96 liter/liter-ethanol.

Although less than the total heating requirement of the plant, heating requirements for the boiler makeup water alone are still substantial. Therefore, this work will focus on studying the feasibility of using solar thermal energy to reduce the natural gas use in heating the boiler makeup water. The heating requirement for the boiler makeup water will be found by determining the amount of heat needed to heat the boiler makeup water from the ground water temperature (T_{gw}) to the boiler input water temperature (T_B). The makeup water heating requirement (Q_{MW}) in kJ/l-ethanol is determined by

$$Q_{MW} = MW_B \times c_{p,w} \times (T_B - T_{gw}) \times \rho, \tag{4}$$

where $c_{p,w}$ is the constant-pressure specific heat of water and ρ is the density of water. Using a boiler temperature of 100°C, a ground water temperature of 15°C, and a MW_B of 0.96, the heating requirement for the makeup water is 342 kJ/liter-ethanol. This is significantly less than the total thermal energy of 8,040 kJ/liter-ethanol reported by the average dry mill plant in Mueller's survey [15], representing approximately 4.2% of the total heating requirement of the plant. However, this system can be isolated and designed to be replaced by a solar thermal array, making it a system worthy of consideration for use of the solar energy resource.

Focusing on using solar thermal arrays for heating the boiler makeup water has further advantages. Preheating boiler makeup water introduces a lower inlet fluid temperature than would be seen in the recycled process water. In turn, this allows a lower temperature of the solar array working fluid, which decreases the heat loss from the collectors. Using low-temperature ground water increases the efficiency of the solar array by reducing heat loss, which increases the total energy the solar array can provide.

The solar energy collected by a proposed solar thermal array can be calculated from monthly or yearly solar resource data, and the model can estimate the thermal energy collected by both evacuated tube and flat plate collectors. Typically, the average monthly solar insolation values in kWh/m^2/day are entered into the model. Monthly resource data will more accurately show the available thermal energy available throughout the year. Other input data to the model include the total area of each collector (A_c), which is the gross area of each of the collectors in the solar array, and the aperture area of each collector (A_a), which is the area of the collector that can absorb sunlight to transfer thermal energy to the working fluid. For flat plate collectors, the aperture area will be between approximately 85 and 95% of the gross area of the collector. Evacuated tube collectors have slightly more variation, so the aperture area can be anywhere between 60 and 85% of the gross collector area.

The installed cost per square meter (IC_{sc}) of the solar collectors will mainly depend on the type of collector and the size of installation. Installed costs can be hard to estimate, because they include costs for the design, permits, piping, panels, pumps, insulation, a heat exchanger, storage tank, and installation. Larger systems will have a smaller cost per square meter due to economies of scale. The installation costs of large projects make up a smaller percentage of the total installed cost. Average prices reported in a 2009 survey of United States solar thermal collector manufacturers were for flat plate collectors at a rate of \$209/m^2 for flat plate collectors and \$279/m^2 for evacuated tube collectors at a rate of [14]. Installed costs are more difficult to estimate due to the large range of project specifications and locations. The IEA [39] reports that installation costs for small-scale solar hot water systems can be up to 50% of the total cost and that large-scale systems generally have lower installation costs compared to the equipment costs. Model inputs for total installed costs for flat plate and evacuated tube arrays are estimated to be in the range of \$314-\$418/m^2 and \$419-\$558/m^2 for each type of panel, respectively. These values are between 1.5 and 2 times the 2009 panel prices reported by US manufacturers.

There are two collector performance variables that determine the amount of solar insolation the collector absorbs and the heat lost to the environment. The variable $F_R(\tau\alpha)$ (where F_R is the collector heat removal factor, τ is the transmissivity, and α is the absorptivity) determines the percentage of solar energy absorbed, and the variable $F_R U_L$ (where U_L is the heat loss coefficient) determines the heat lost to the environment due to the temperature difference between the ambient air (T_a) and the input fluid temperature (T_i). The total useful solar energy (Q_u) in MJ/yr transferred to the working fluid is calculated using

$$\begin{aligned} Q_u &= L_f A_c N_p \left[F_R(\tau\alpha) G_t - F_R U_L (T_i - T_a)(H_{day} - 2)\right] \\ &\quad \times \frac{3600s}{hour} \times N_d, \end{aligned} \tag{5}$$

where L_f is the load factor of the solar array, N_p is the number of solar panels, G_t is the solar insolation on a tilted surface, H_{day} is the number of hours of sunlight in one day, and N_d is the number of days. Flat plate collectors have $F_R(\tau\alpha)$ values between 0.6 and 0.8, while evacuated tube collectors have values typically between 0.5 and 0.6 based on gross collector area [40]. This means that flat plate collectors will capture more solar energy than evacuated tube collectors due to a less reflective surface. Values of $F_R U_L$ for flat plate collectors

range from 3.5 to 6 W/m^2-°C and range from 0.7 to 3 W/m^2-°C for evacuated tube collectors based on gross collector area [40]. Flat plate collectors will lose significantly more energy due to temperature differences between fluid temperature and ambient air temperature. Specific values of $F_R(\tau\alpha)$ and F_RU_L may be available from collector manufacturers but can also be found through the RETScreen database [40] of collector efficiency values. Average values for these performance variables are used to compare the performance of flat plate and evacuated tube collectors at various ethanol plant locations. The variables used to model flat plate collectors were 0.72 and 4.5 W/m^2-°C, and the variables used for evacuated tube collectors were 0.59 and 1.5 W/m^2-°C. Panels with higher values for $F_R(\tau\alpha)$ and lower values for F_RU_L are usually more expensive because they have a higher efficiency. The model can simulate adjustments in price and performance variables to weigh the benefits and disadvantages of increased performance with increased cost.

The total useful energy available for water heating is reduced by a user-defined load factor (L_f). The load factor can be less than or equal to 1.0 depending on anticipated heat losses and reduced capacity. This value accounts for additional heat loss from piping or storage tanks as well as reduced operation time due to excessively cold temperatures or low solar energy days. Solar collector arrays will only operate when the collectors are receiving sufficient energy from the sun. This means that there will always be some solar energy that is wasted, because at times the energy received is too low to warrant operating the system. Flat plate collectors will have a lower load factor than evacuated tube collectors because they cannot utilize as much solar energy during the morning and evening hours when the incidence angle is not optimal. Flat plate collectors lose more heat due to extreme temperatures as well, which may not be accounted for if the user enters yearly averages for the solar insulation and ambient temperature. The load factor can also be adjusted to simulate nonideal solar conditions or reach the desired solar collector efficiency.

The solar insolation incident on the tilted surface of the collector (G_t) in kWh/m^2/day is the total solar energy that hits the collector. The heat loss coefficient (U_L) in W/m^2-°C is converted to J/m^2-°C-day by multiplying by the approximate number of seconds the collector is in operation per day. For monthly solar data this value is 3600 s/hr multiplied by the number of sunlight hours per day (H_{day}) minus two. Subtracting two from the sunlight hours accounts for the fact that early morning and evening solar energy is too weak to effectively operate solar arrays. By multiplying the total useful solar energy per day by the number of days, N_d, as shown in (5), one obtains the useful solar energy per year.

The model allows for the input data to be based on yearly or monthly averages. For monthly input data a separate value for useful solar energy is calculated for each month by using the average number of days in a month: 30.417 days/month. Then the monthly values are added to give the yearly useful energy. Yearly input data uses 365 days per year to calculate the total useful energy. Use of monthly data is advantageous for it allows for the relative differences in solar energy throughout the year, which can help the user predict changes in solar thermal energy input and also help size the array to ensure that peak summer output will not be too large.

The performances of solar thermal collectors are often compared on the basis of efficiency. There is some debate on the best way to measure efficiency, so this model calculates the efficiency of the total solar array and modeled panel based on both gross collector area and aperture area. The efficiency measured by aperture area will always be larger than the efficiency measured by gross collector area, but evacuated tubes usually benefit more from aperture efficiencies. This is because a lower percentage of their total area can collect solar energy. Equation (6) determines the total solar energy incident on the tilted surface of a collector array. Equation (7) gives the total energy incident on the aperture area of the solar array.

$$Q_c = A_c N_p G_{ta} \times \frac{3600s}{hour} \times \frac{365days}{year}, \tag{6}$$

$$Q_c = A_a N_p G_{ta} \times \frac{3600s}{hour} \times \frac{365days}{year}. \tag{7}$$

Both of these calculations use the yearly averages for solar insulation on a tilted surface (G_{ta}) in kWh/m^2/day. These values are then used to find the total efficiency of the solar array for gross area (η_c) and aperture area (η_a):

$$\eta_c = \frac{Q_u}{Q_c}, \tag{8}$$

$$\eta_a = \frac{Q_u}{Q_a}. \tag{9}$$

These efficiencies are then divided by the load factor to find the average efficiency of the panels in the array based on gross area (η_{cp}) and aperture area (η_{ap}):

$$\eta_{cp} = \frac{\eta_c}{L_f}, \tag{10}$$

$$\eta_{ap} = \frac{\eta_a}{L_f}. \tag{11}$$

Values for panel efficiency are more readily available than the performance variables $F_R(\tau\alpha)$ and F_RU_L, so these calculated efficiencies can be compared to published, calculated, or measured efficiencies to verify and adjust the performance variables used in the model.

4. Model Verification

The model for a solar thermal collector was calibrated and verified by comparing the calculated efficiency of the model to the experimental efficiency coefficients reported by SPF [1]. First the model outputs for various values for $F_R(\tau\alpha)$ and F_RU_L were evaluated to determine the most realistic combination for a flat plate and an evacuated tube collector. RETScreen [40] estimates for $F_R(\tau\alpha)$ and F_RU_L were used along with SPF test data [1] to determine the optimal values for each collector. The average values from SPF were used

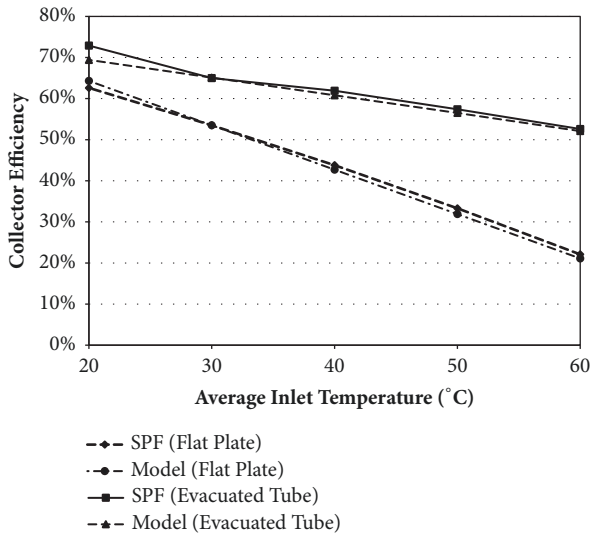


Figure 1: Comparison between the calculated efficiency values from the model and the SPF [1] efficiency coefficients for a flat plate and evacuated tube array based on aperture area.

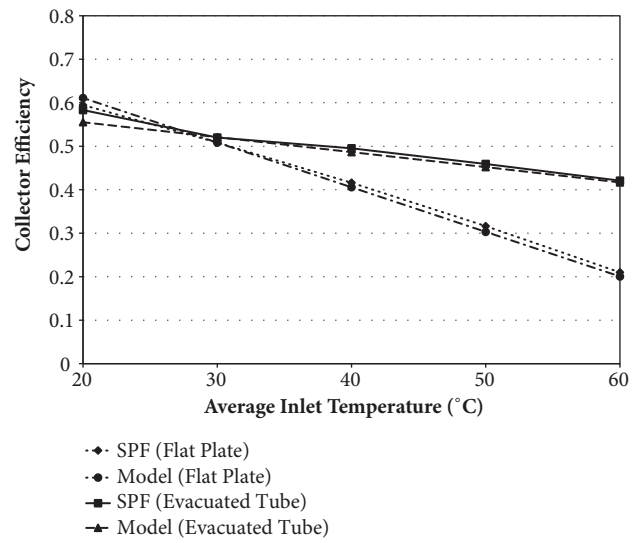


Figure 2: Comparison between the calculated efficiency values from the model and the SPF [1] efficiency coefficients for a flat plate and evacuated tube array based on gross area.

with the solar insolation and average ambient temperature data to calculate the useful solar energy produced each month for a flat plate and evacuated tube collector. These values were used to find the average yearly efficiencies of both collectors.

The model uses the temperature of the fluid at the inlet of the panel, while the SPF efficiency calculations use the mean temperature of the fluid in the panel. It was assumed the mean temperature of the working fluid would be 10°C above the inlet temperature. The aperture area of the flat plate and evacuated tube collectors was assumed to be 95% and 80% of the gross area, respectively. The values for $F_R(\tau\alpha)$ and $F_R U_L$ that best followed the SPF efficiencies were 0.72 and 4.5 W/m^2-°C, respectively, for a flat plate collector and 0.59 and 1.5 W/m^2-°C, respectively, for an evacuated tube collector. The solar insolation and average ambient temperature data for Arthur, Iowa, United States, was used to find the yearly efficiency of the solar array at different inlet fluid temperatures using the model and the SPF values. The yearly efficiency found from the model and the efficiency found from the SPF data are both shown in Figure 1 for flat plate and evacuated tube collectors at various inlet fluid temperatures. The model and SPF values show the same behavior for the respective panels. The model accurately estimates the energy production of a flat plate and evacuated tube collector. These values are for the panels only and not the entire system. There will be additional losses from the system that can be accounted for by adjusting the load factor (L_f) of the solar array.

Many solar collector efficiencies are reported according to gross area instead of aperture area. The same data were converted to efficiency values based on gross area and are shown in Figure 2. Due to a smaller aperture area, evacuated tubes suffer slightly from gross area efficiency calculations, but they also have significantly high costs per square meter. Regardless of the method of calculation, evacuated tubes would provide more energy for an ethanol plant in Arthur, IA, but the additional cost may not warrant the efficiency increases.

5. Results and Discussion

The energy production and payback periods for both flat plate and evacuated tube collectors were evaluated for 18 ethanol plant locations. Figure 3 shows the annual useful energy production for a 5,000 m^2 solar array of both flat plate collectors and evacuated tube collectors with an average input temperature of 30°C. The load factor was set at 90% for both collectors. The performance of the flat plate and evacuated tube collectors is very similar for the Midwestern states (Illinois, Indiana, Iowa, Kansas, Minnesota, North Dakota, South Dakota, and Wisconsin) due to the low inlet temperature. The flat plate collectors do demonstrate better performance over the evacuated tube collectors in Texas, California, and Arizona, which have higher ambient temperatures.

Figure 4 shows the annual useful energy production of the same solar array with an increased inlet temperature of 60°C. The larger inlet temperature significantly reduces the total energy production of the system for all plant locations. Evacuated tubes show much better performance than flat plate collectors with the larger inlet temperature. In most of the Midwestern states, the flat plate panels produce less than half the energy produced in the evacuated tubes with this inlet temperature. It is clear that evacuated tube collectors in cold climates will greatly benefit from increased working fluid temperature. Solar resources are very consistent in similar areas of the country, which means conclusions drawn for these particular ethanol plant locations can be applied to nearby locations.

These results also indicate that the model agrees with concepts already noted in industry. Cold climates and large

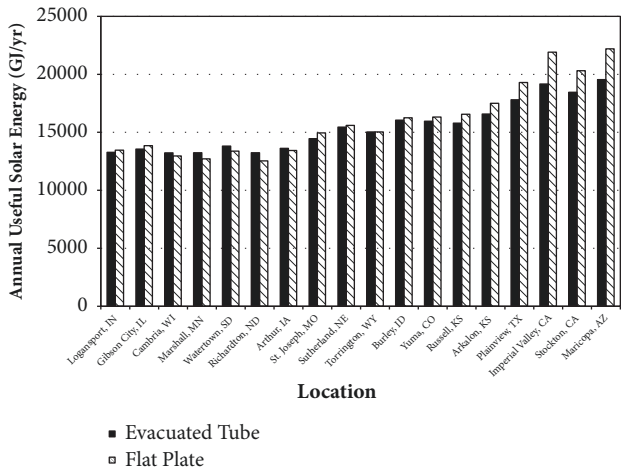
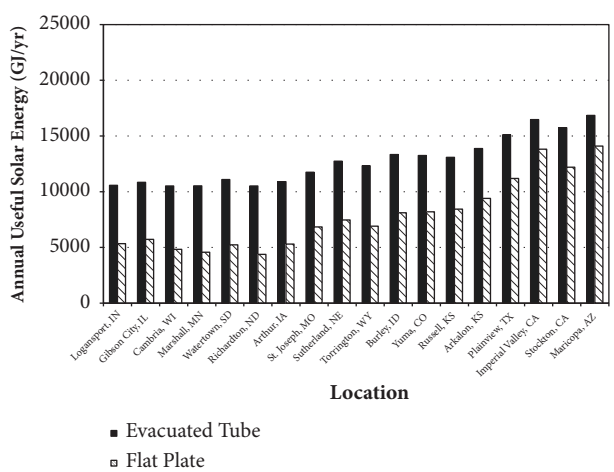


Figure 3: Model of a 5,000m^2 gross area flat plate and evacuated tube collector array for solar resources at 18 ethanol plant locations and an average inlet temperature of 30°C. For the flat plate collector, $F_R(\tau\alpha)$ =0.72 and $F_R U_L$ = 4.5 W/m^2-°C), and for the evacuated tube collector, $F_R(\tau\alpha)$ =0.59 and $F_R U_L$ = 1.5 W/m^2-°C).



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differences between the working fluid temperature and the ambient temperature favor evacuated tube collectors in practice. The fluid temperature in the solar array has a large impact on the annual useful energy produced by the array. Cold ambient temperatures negatively affect the efficiency of both flat plate and evacuated tube collectors, but flat plate panels suffer a much higher penalty. These are all proven concepts in the solar thermal industry [39], and this model confirms these principles and demonstrates the magnitude of these differences.

Despite the large size of the array considered, the total percent shift from natural gas heating to solar heating is low for all four scenarios considered above. The total heating requirement for all of the ethanol plants was assumed to

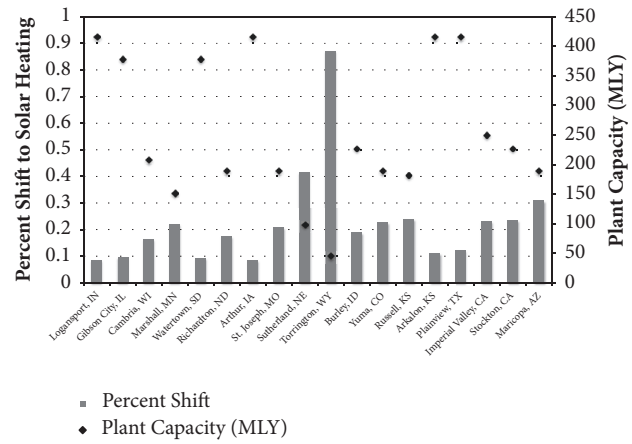

Figure 5: Total plant capacity (in million liters/year) and percent shift to solar heating of the boiler makeup water using a 5,000 m^2 flat plate array at 18 ethanol plants.

be 8,080 kJ/liter-ethanol. The total percent shift to solar thermal energy for the 5,000 m^2 flat plate array with an inlet temperature of 30°C ranged between 0.4% and 4.1%. Most of the locations had less than 1% shift to solar energy from natural gas. These are very small percentages and may deter any further investigation, but total percent shift is not a good measure of the useful heating that could be accomplished by a nonconcentrating solar array.

As discussed above, considering using the solar heating for heating the boiler makeup water portion of the total heat load provides a much more reasonable approach. Using the solar heating for the boiler makeup water allows one to modify a single subsystem rather than modifying an entire ethanol production facility for use of solar heating. The percent shift to solar heating of the boiler makeup water for the flat plate array with an inlet temperature of 30°C (modeled in Figure 3) is shown in Figure 5 along with the total production capacity for each ethanol plant. The largest percent shift is for the Torrington, WY, plant with an 87% shift. This very large percentage would be oversized for the 45 MLY plant, because peak summer solar heating would most likely far exceed the plant's makeup water heating needs. All of the other plants show shifts below 50%. Even with the low percent shift to solar heating, the size of this array is quite substantial. The gross area of the collectors is taken to be 5,000 m^2. While this is a large area, ethanol plants typically are built on many acres of land and have large flat roofs that could be used for installing the solar array; therefore, the array size could often be larger if desired. If one wanted to shift more of the boiler makeup water heating to solar heating, one could increase the size of the installed array. While larger arrays would have larger initial costs, economies of scale could decrease the payback period of a larger array.

The payback periods for a flat plate and an evacuated tube array for all of the ethanol plant locations were compared. Figure 6 shows the cumulative cost savings over a period of 20 years for a flat plate solar thermal array for six of the 18 ethanol plants. Some manufacturers claim lifespans for

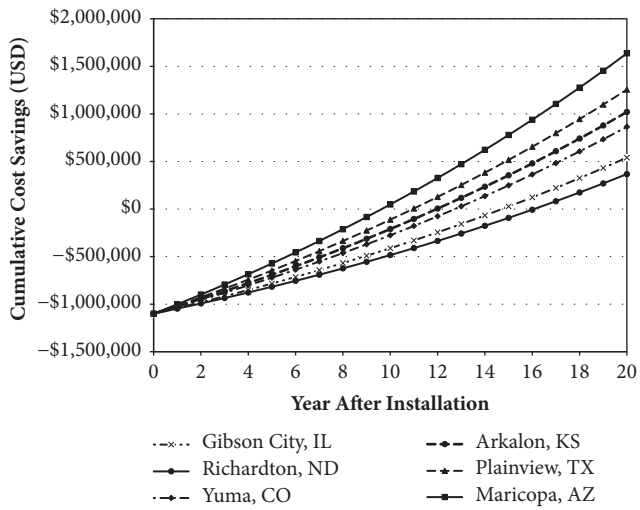

Figure 6: Modeled cumulative cost savings (in United States dollars) of a standard flat plate solar array for selected ethanol plant locations. Model input values: $F_R(\tau\alpha) = 0.72$, $F_R U_L = 4.5$ W/m^2-°C, $T_i = 30$°C, $R_{NG} = \$4.74$/GJ (initial price of natural gas), $n_{NG} = 3.3\%$ (annual increase in price of fuel), $IC_s = \$220/m^2$.

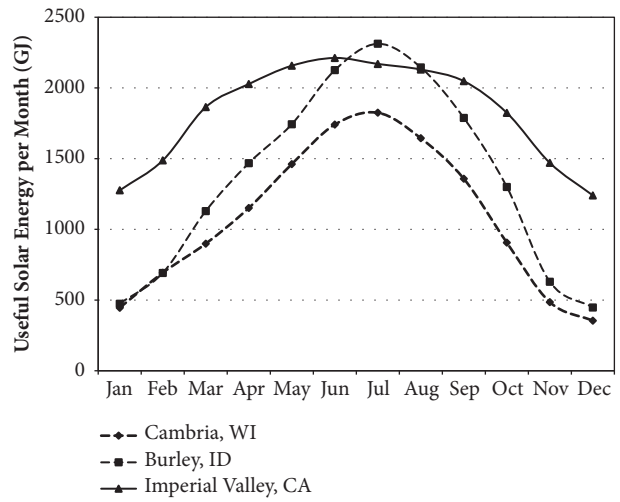

Figure 7: Monthly useful energy from a 5,000 m^2 flat plate array for Cambria, WI, Burley, ID, and Imperial Valley, CA.

solar thermal panels up to 30 years, but 20 years would be the most common [39]. The modeled 5,000 m^2 array had an estimated installed cost of \$314/m^2 with a government rebate of 30%, which brought the installed cost down to \$220/m^2. The average inlet temperature was set to 30°C. The initial natural gas price was set at \$4.74/GJ, and an annual rate increase of 3.3% was chosen. A load factor of 90% was used to account for additional heat losses and inefficiencies in the system. These six locations were chosen to show the range of conditions for the payback analysis. All of the plants not shown had payback periods between the two extremes. Maricopa, AZ, had the shortest payback period at about 9 years, while Richardton, ND, had the longest payback period at about 15 years. The efficiency of the entire array was 58% for Maricopa, AZ, and 44% for Richardton, ND. This seemingly small difference in efficiency had a large impact on the payback period and cumulative savings of the two projects. The payback periods are far above the typical payback period that businesses seek, but all of the solar arrays have paybacks well before an anticipated lifespan of 20 years; after the initial costs have been repaid in savings, further savings result in increased cost savings and continued reduction in natural gas usage. If additional rebates or tax incentives are applied the payback period would decrease and the lifetime savings would increase.

The variation in solar energy throughout the year is another factor to consider when installing a solar thermal array. Figure 7 shows the monthly useful energy output of the 5,000-m^2 flat plate array with an inlet temperature of 30°C modeled for Figure 3. Only three locations are shown because the other locations show behavior similar to one of these three distributions. Burley, ID has the largest range of energy production with over four times as much energy produced in July compared to January. Imperial Valley, CA, had one of the smallest ranges with production in June less than double the production in December. This indicates that, even with the most favorable ethanol plant locations in the United States, useful energy from a solar array will change significantly throughout the year and should be considered when sizing an array.

The price of natural gas varies widely across the United States. This can significantly affect the payback period and cumulative cost savings for a solar project. The same flat plate solar array modeled in Figure 6 was used to model the changes in payback period due to adjustments to the natural gas price. All other variables were kept constant. The average natural gas prices for California, Texas, Arizona, and Missouri for 2011 in Table 1 were used to more accurately model the payback period for solar arrays in these states. The model results for both the US average natural gas price of \$4.74/GJ and the average state natural gas prices for Imperial Valley, CA, and Plainview, TX, are shown in Figure 8. The natural gas price for Texas was \$3.90/GJ, and the average price was \$6.52/GJ for California [41]. The payback periods and cumulative cost savings for the Texas and California plants were very close for the average US gas price but diverge when using the state gas rates. The payback period for California went from just over 9 years to less than 7 years. The cumulative cost savings increased by approximately \$1.1 million after 20 years. The lower natural gas rate in Texas increased the payback period by two years and decreased the cumulative savings by approximately \$450,000. The actual rate an ethanol plant pays for their natural gas use will be one of the main determining factors in the profitability of a solar thermal array.

The rate paid for natural gas can compensate for sizeable differences in solar resources. Even though the modeled flat plate array in Figure 3 in Arizona produced over 30% more energy than the same array in Missouri, use of the average natural gas prices in Missouri and Arizona resulted in the solar installation in Missouri being nearly as economical

Table 1: State natural gas rates (2011 data) and payback period modeled for a realistic flat plate collector [41].

Location	Natural Gas Price (USD/GJ)	Payback Period (years)	First Year Cost Savings (USD/yr)
Logansport, IN	5.23	14.0	$63,331
Gibson City, IL	6.25	11.8	$78,065
Cambria, WI	6.44	12.2	$74,704
Marshall, MN	5.16	14.9	$58,551
Watertown, SD	5.58	13.3	$67,117
Richardton, ND	4.71	16.1	$52,657
Arthur, IA	5.41	13.6	$65,362
St. Joseph, MO	7.81	9.1	$106,214
Sutherland, NE	5.16	12.4	$73,435
Torrington, WY	4.55	14.1	$62,242
Burley, ID	5.92	10.6	$88,250
Yuma, CO	5.41	11.4	$80,895
Russell, KS	5.10	11.8	$77,542
Arkalon, KS	5.10	11.2	$82,357
Plainview, TX	3.90	12.9	$69,911
Imperial Valley, CA	6.52	7.4	$134,057
Stockton, CA	6.52	7.9	$123,613
Maricopa, AZ	6.36	7.5	$132,576

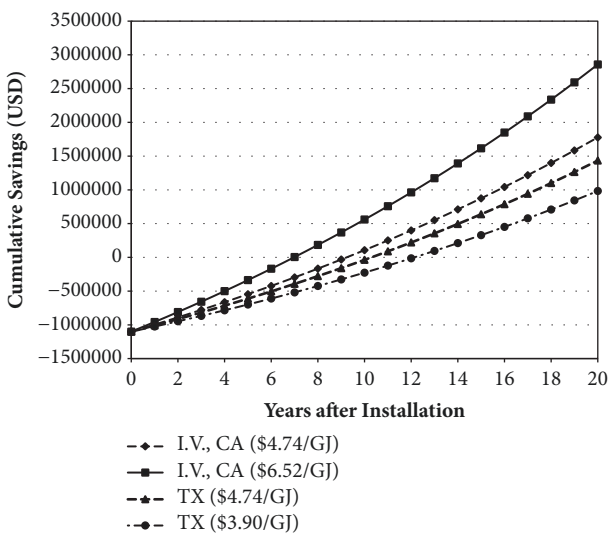

Figure 8: Modeled cumulative cost savings and payback period for Texas (TX) and Imperial Valley, California (IV, CA), ethanol plants using the national and state natural gas prices. Model input values: $F_R(\tau\alpha) = 0.72$, $F_RU_L = 4.5$ W/m^2-°C, $T_i = 30$°C, $n_{NG} = 3.3\%$, $IC_s = \$220/m^2$.

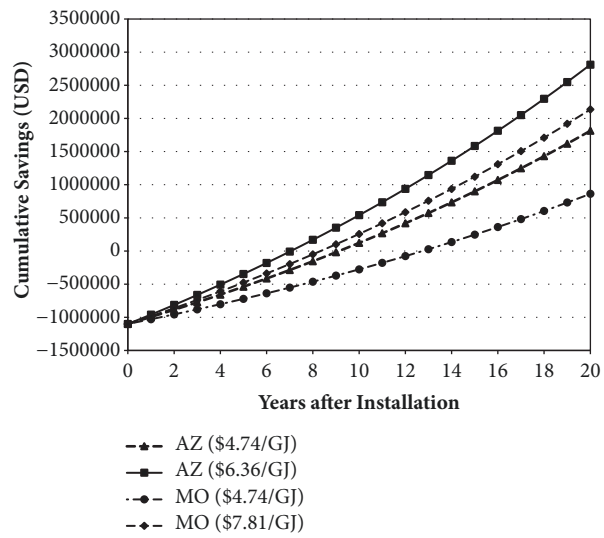

Figure 9: Modeled cumulative cost savings and payback period for Arizona (AZ) and Missouri (MO) ethanol plants using the national and state natural gas prices. Model input values: $F_R(\tau\alpha) = 0.72$, $F_RU_L = 4.5$ W/m^2-°C, $T_i = 30$°C, $n_{NG} = 3.3\%$, $IC_s = \$220/m^2$.

as the installation in Arizona. Figure 9 shows the model results for the payback period and cumulative savings for the national average natural gas rate and the state gas rate for the solar array in Missouri and Arizona. The increased gas price of $7.81/GJ decreased the payback period to less than 9 years, which is 4 years less than the payback period using the national rate of $4.74/GJ. The cumulative savings over 20 years increased by approximately $1.2 million as well. These values are all more favorable than the Arizona solar array using the national gas rate. This shows that the natural gas price can be a more important factor than the available solar resource in determining the economic feasibility of a solar thermal project. The modeled array for Arizona becomes even more promising when the state gas rate of $6.36/GJ is used. The payback period decreased to just over 7 years, which is a reduction of 2 years. The cumulative savings over a 20-year period of the solar array are nearly $3 million. These results clearly show that accurate natural gas rates are

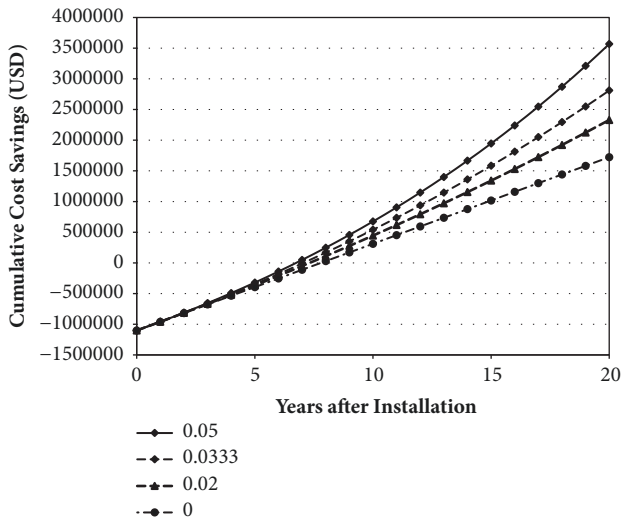

Figure 10: Modeled cumulative cost savings and payback period for a flat plate array in Maricopa, AZ, with four different percent price increases for natural gas. Model input values: $F_R(\tau\alpha) = 0.72$, $F_R U_L = 4.5$ W/m^2-°C, $T_i = 30$°C, $IC_s = \$220/m^2$.

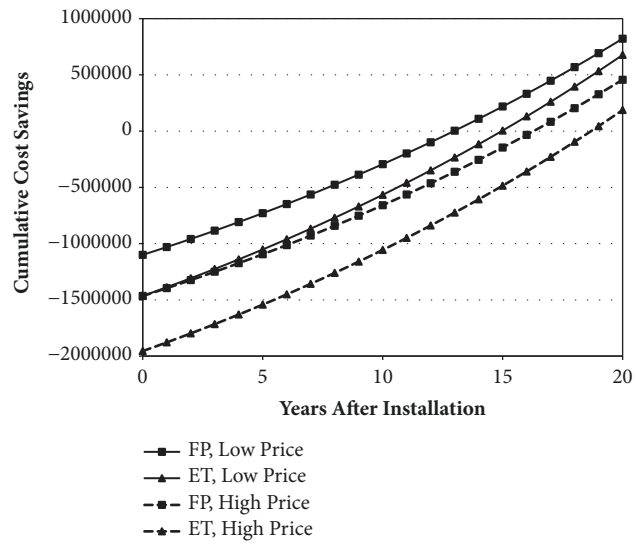

Figure 11: Modeled cumulative savings and payback period for low and high installed costs for a standard flat plate (FP) and evacuated tube (ET) collector array in Sutherland, NE.

extremely important in determining the financial outcomes of a solar thermal project.

The cumulative savings can be slightly misleading because as the system ages it will likely need more maintenance. Some of the cost savings will be used to maintain the system and make upgrades, but these costs should be significantly less than the total savings per year. It is also not guaranteed that the system will still be operating at an acceptable level after 20 or more years. It is likely that the efficiency of the system will decrease slightly as the materials age. This will reduce the cost savings predicted by the model. These are all factors to consider when planning for the potential savings of a solar array.

While natural gas is not currently anticipated to significantly increase in price in the near future, an increasing price of natural gas can influence the cumulative savings from a solar project but will not have a large reduction in the payback period. Figure 10 shows the same flat plate array described for Figure 6 for Maricopa, AZ, with four different annual percent price increases for natural gas. The payback period and cumulative cost savings are shown for a steady natural gas price of \$6.36/GJ over a 20-year period, as well as annual price increases of 2%, 3.33%, and 5%. The payback periods for the steady rate, 2% and 3.33%, are all between 7 and 8 years, and the 5% rate increase shows a payback period between 6 and 7 years. The main difference between these rate increases is the total cost savings. After 20 years, with a 5% rate increase, the cumulative cost savings are approximately \$1.8 million more than the steady gas rate. It should be noted that very large values for the lifetime savings of a solar array are possible if the price of natural gas increases at an unexpectedly high rate.

All of the simulations of payback periods shown previously used the low installed cost estimate of $\$314/m^2$ for flat plate collectors with a 30% government incentive. The 30% United States federal government incentive is currently available for solar thermal systems through the year 2016 [42], so it will be considered for all simulations. Payback periods for the low and high costs of flat plate and evacuated tube collectors are compared for a 5,000 m^2 gross area solar array in Sutherland, NE, in Figure 11. The input variables for the model are shown in Table 2. The load factor for the flat plate array is 0.85 and the load factor for the evacuated tube array is 0.90; this accounts for reduced solar absorption in the flat plate array when the sun is low in the sky. The flat plate array installed costs were considered to be $\$220/m^2$ for the low cost scenario and $\$293/m^2$ for the high cost scenario, and the prices of $\$293/m^2$ and $\$391/m^2$ were used for the evacuated tube arrays scenarios. An inlet temperature of 35°C was used in all cases. The low-priced flat plate collector had the shortest payback period at 13 years while the low-priced evacuated tube collector was at 15 years, the high-priced flat plate collector was at 16 years, and the high-priced evacuated tube was at 19 years. Note that all of these payback periods are most likely too long to be considered economically feasible for an ethanol plant. The low-priced evacuated tube collector begins to draw nearer the low-priced flat plate collector as more years pass. The increased solar energy available from the evacuated tube collector begins to make up for the high installed cost but does not reach the cumulative savings of the flat plate collector until after 20 years. Also, it is important economically for prices to be lowered, such as through lower-cost collectors or through government incentives.

The payback period for a realistic flat plate array was modeled using the individual state natural gas prices for all of the ethanol plant locations. All of the standard input values were used for the flat plate collector except the load factor. The load factor was increased to 90% to model a well-designed system with minimal losses. The lower installed cost of $\$220/m^2$ was used because the size of the system should provide savings in bulk discounts on equipment, and a 30%

Table 2: Model inputs for the simulation results shown in Figure 11 for different installed costs of the solar collectors.

PRICE INPUTS		
	Flat Plate	**Evacuated Tube**
Current Average Price of Natural Gas for Industrial Sector, R_{NG} ($/GJ)	5.16	5.16
Natural Gas Percent Price Increase per Year, n_{NG}	0.033	0.033
SOLAR INPUTS		
Total Area of Each Collector, A_T (m^2)	5	5
Number of Panels, N_p	1000	1000
Price per square meter, IC_{sc} (USD/m^2)	$220 / 293	$293 / 391
$F_R(\tau\alpha)_n$	0.72	0.59
$F_R U_L$ (W/m^2-°C)	4.5	1.5
Input temperature of working fluid, T_i (°C)	35	35
Load Factor, L_f	0.85	0.9

Investment Tax Credit (ITC) was applied. Table 1 shows the natural gas price and the payback period for this array for all of the ethanol plant locations. Only three states studied have payback periods less than ten years, which include Arizona, California, and Missouri. These three states are the best locations to consider implementing a solar thermal array. California and Arizona have ample solar resources with mid-range natural gas prices to provide payback periods less than 8 years. Missouri is a good candidate for a solar array due to moderate solar resources and a high natural gas price. All three states have yearly natural gas cost savings over $100,000 for the first year. Solar thermal systems could be practical in Idaho, Kansas, and Colorado if additional incentives are available through federal and local programs. If substantial financial assistance and backing for solar thermal projects become available through additional government programs, then a flat plate array may become feasible for most of the other ethanol plant locations. It is unlikely that any amount of financial assistance would make a solar thermal array practical for an ethanol plant in North Dakota due to the low solar resources and low natural gas price.

This model is meant to aid in the beginning stages of a solar thermal project but is not intended to be a complete representation of all the factors that must be considered when planning a renewable energy project. There are several key aspects that are not addressed by this model. The cost of debt and specifically the interest on loans acquired to install the renewable energy project are not considered in the calculation of payback period or cost savings. This could influence the economics of the project. Operation and maintenance (O&M) costs can be included in the model by reducing the price of energy, but there are no specific methods to account for additional maintenance costs as the system ages or specific inputs to calculate these costs separately. Generally O&M costs are significantly lower than the yearly savings of the system, but these costs may influence payback period and lifetime project savings. The model also does not account for the depreciation of the solar array. A business owner may be able to claim the depreciation of the renewable energy project as a tax deduction, which would improve the finances of the project as a whole.

6. Conclusions

Ethanol production plants are often in good locations for the consideration of the application of solar thermal projects. The rural setting of most ethanol plants provides ample space for a solar installation with fewer logistical concerns than more populated areas. Corn ethanol production is predicted to increase slightly over the next 20 years, although opponents of ethanol often cite the large energy requirements and the use of fossil fuels as two of the main arguments against corn ethanol. But the use of solar energy for heating can reduce the fossil fuel consumption in the production of this renewable fuel. Analysis of the heating requirements for ethanol production quickly shows that meeting all of the requirements with solar heating is impractical. But the results of the modeling show that a large solar thermal collector array can shift about 10-20% of the boiler makeup water subsystem heating requirement for large ethanol plants in the United States.

Solar thermal projects are most profitable in the Southwest, but high natural gas prices can dramatically improve the economics of a solar thermal array. California and Arizona are ideal locations for solar thermal projects, but very few ethanol plants are located in these states. Missouri is home to a larger number of ethanol plants and has a high natural gas price, which vastly improves the profitability of a solar array in this state. Solar thermal systems in many other states are generally only feasible if the actual natural gas rate paid by the plant is well above the state's average rate.

The profitability of solar thermal arrays depends greatly on government incentives. The Investment Tax Credit (ITC) reduces net installed costs, which decreases the payback period and allows solar projects to be more profitable. Payback periods are generally long for solar thermal systems even in areas with high solar resources and anything that can keep these timeframes lower will improve the economics of installing solar thermal arrays. Rate increases for natural gas do not have a large effect on payback periods but can impact long-term profitability.

Overall, the model indicates that the installation of solar thermal arrays at ethanol production facilities will not result in short-term economic benefits but generally will be

economically profitable before the anticipated lifetime of the equipment is reached. Furthermore, the use of solar thermal heating will reduce the consumption of nonrenewable fossil fuels, increasing the true renewability of ethanol as a fuel.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors have no conflicts of interest associated with this work.

Acknowledgments

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