EMERGING
SOLAR TECHNOLOGIES

Feasibility Study and Cost Analysis

Prepared for

College of Marin

January 22, 2006
Executive Summary

Alfa Tech Cambridge Group (ATCG) was engaged to evaluate emerging solar technologies, recommend the most appropriate for College of Marin projects, computer model and provide a cost analysis of the systems, and list rebate and incentive programs. ATCG hired High Sun Engineering, a California specialist in solar energy, to measure solar radiation at seven sites on the Kentfield and Indian Valley campuses, create computer models of energy production from different photovoltaic system configurations, and advise on cost and incentive matters.

The sites studied were
- Diamond PE Center
- Performing Arts
- Science/Math/Central Plant
- Fine Arts
- IVC Main
- Pomo 1 (Auto Shop Building)
- Pomo 2 (Transportation / Auto Tech Lab)

Crystalline photovoltaic modules are generally the best technology, with thin-film modules recommended for the Diamond PE Center. A solar thermal system is recommended for the swimming pools.

Costs are presented for attaining production of 50% of electrical needs for each building. The roof areas are not large enough for 50% generation; separate structures such as parking lot screens are included in the cost.

Financial Analysis Summary of Recommended PV Options for 50% Load

<table>
<thead>
<tr>
<th>Building</th>
<th>Installed Cost</th>
<th>Incentive</th>
<th>Net Cost</th>
<th>Payback Year</th>
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<tbody>
<tr>
<td>PE</td>
<td>$2,778,479</td>
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<td>$2,411,989</td>
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<tr>
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<td>$505,832</td>
<td>$4,433,225</td>
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<td>$1,044,500</td>
<td>$11,012,061</td>
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<td>Pomo 1</td>
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<td>$102,829</td>
<td>$805,903</td>
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<tr>
<td>Pomo 2</td>
<td>$1,036,311</td>
<td>$127,784</td>
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<td>TOTAL</td>
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<td>$2,986,403</td>
<td>$27,535,224</td>
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</tr>
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</table>
Solar Technology Overview

There are two types of solar energy systems: Photovoltaics (PV) and thermal.

Photovoltaic modules convert sunlight into DC electricity which is transformed by an inverter into AC and connected into the main electrical panel to feed a particular service. Any excess spins the meter backwards and credits the account at full retail rate according to the California Net Metering Law.

Thermal collectors use sunlight to warm water that is circulated for domestic consumption, pool heating, or space heating.

This report addresses primarily PV systems at the College of Marin. Appendix E contains a discussion of thermal systems for swimming pool heating at the Diamond PE Complex.

Photovoltaic Technology

There are currently two basic types of PV technology available on the market: crystalline and thin-film. A standard module includes PV cells which are electrically connected, encapsulated with a clear plastic material, and sandwiched between glass and a glass or vinyl backing material. An aluminum frame and wiring junction box complete the module. When exposed to light, a standard PV module generates from 15 to 50 volts of direct current (DC) depending on the design. PV systems include one or more strings of 6 to 18 PV modules in each, wired in series and operating at 300 to 500 volts DC. Direct current output is converted to alternating current (AC) by an inverter.

Crystalline Photovoltaics

Referred to as the “first wave” of PV development, crystalline photovoltaics were developed for space applications and began finding terrestrial markets in the 1970s. The most common types are single crystal (cells made from a single whole crystal), polycrystalline (cells made from rapidly cooled molten silicon which fractures into multiple crystals), and ribbon (cells pulled in a “ribbon” from a molten silicon bath).

Though crystalline PVs were challenged by the arrival in the mid-nineties of thin-films, the technology has maintained market dominance by steadily lowering manufacturing costs and increasing cell efficiency. There are currently about 20 crystalline PV manufacturers with products that are available and approved for use in California. Most of these companies have contractors in the Bay Area who sell and install their products.
The advantages of crystalline PVs are proven longevity, competitive prices, wide availability, fabrication from common silicon, and high efficiency. Crystalline PV modules come with a 20 to 25 year warranty on power output and will likely last 30 to 40 years in the California climate (hot humid areas see lifetimes closer to the warranty period). After the first few months of initial stabilization, crystalline PV modules have power degradation rates on the order of 0.25% to 1% per year.

**Thin-Film Photovoltaics**

Thin-film PVs were originally promoted as the solution to the high capital cost of PV—they would be so much cheaper to manufacture that their lower efficiency would not matter. Ten years later, this “second wave” of PV development has yet to show substantial cost reductions. Thin-film modules sometimes cost less per watt but need around 3 times the surface area as crystalline to produce the same amount of power. The higher materials and labor cost due to extra area usually eliminates them typical residential and commercial building projects. Thin-films have done well in certain niche markets like solar roofing applications, remote power, and consumer electronics.

Thin-film PV modules for use on buildings are constructed as standard modules with glass or plastic cover and aluminum frame or they made into building integrated PV (BIPV) products. The advantages of thin-films are slightly better performance in shaded conditions, a better temperature coefficient, and less silicon for fabrication. Most thin-film modules have a 10 year warranty on power output; the best have a 20 year warranty. Amorphous silicon thin-film modules usually have a longer initial stabilization period than crystalline, during which the output drops significantly, but once stabilized the degradation rates are similar although not as well documented.

There are currently 3 or 4 thin-film PV manufacturers with products that are available and approved for use in California. To our knowledge there has not been an installation of thin-film PV modules on the scale of this project.

**Hybrid Crystalline/Thin-Film**

Efforts have been made to hybridize crystalline and thin-film, to capitalize on the advantages of each. Though AstroPower’s silicon film attempt about 5 years ago failed, Sanyo has patented a technology that uses crystalline cells beneath a semi-transparent thin-film layer. Their module is available in California, but high demand has enabled Sanyo to maintain the highest price per watt in the industry.

**Building Integrated Photovoltaics**

There are some 8 to 10 BIPV products available in California. They are designed to replace standard roofing materials such as tile, cover standard roofing materials such as membrane or standing seam, or replace glass used in facades and skylights. There are also tile-type products that can be used with roofing shakes like those at IVC.
Determining the suitability and cost-effectiveness of BIPV systems is highly building-specific, and will need to be investigated more closely during the each project’s design phase. In some cases BIPV can provide a superior aesthetic and a competitive price.

**New Developments**

PV R&D efforts are focused on two primary targets: Efficiency increase and manufacturing cost reductions. While these two factors are present in most new product developments, they also define the two camps competing for dominance of the “third wave” of PV development.

The efficiency camp, led by Sanyo, SunPower, and Martin Green at the University of New South Wales, holds that major increases in cell efficiency is the key to lower end-user prices. Costs of raw materials, manufacturing, shipping, warehousing, and installation costs remain the same, but as power output increases, cost per unit of generated power lessens.

The two most noteworthy developments are SunPower’s 315 watt modules which use high efficiency, back contact PV cells, and Sanyo’s new HIT high efficiency modules which use their hybrid thin-film/crystalline cells. Another development from Sanyo for non-roof mounted applications is their HIT Double module which uses a bifacial cell with active PV material on the front and the back to catch reflected light from the ground. SunPower and Sanyo have created high efficiency products that can reduce the surface area by 30% compared to a standard crystalline PV arrays. Currently the higher module prices negate most of the efficiency advantage, but in specific applications the benefits may make a difference.

The cost reduction camp, led by Stanford Ovshinsky of UniSolar and a handful of new PV startups who produce thin-film products, holds that major reductions in manufacturing costs is the key to lower end-user prices. When thin-films can be printed like newspaper, the end-use price will drop despite the greater surface area, support materials, and labor costs due to efficiencies of about half to a third that of crystalline.

It is too early to tell whether their good ideas will develop into products that reliably produce power for 30 or 40 years. The only company with enough experience to recommend at this time is UniSolar, which makes a triple junction amorphous silicon thin-film framed module and several BIPV roofing products that might be used at College of Marin.

It is worth noting that there is a third camp, an offshoot of the efficiency camp, that holds that end-user prices are best reduced by increasing the amount of light striking the PV cell. While there are now a half dozen companies developing concentrator...
modules with concentrations from 10 to 300 suns, none of them have a product
designed for roof mounting with enough of a track record to recommend at this time.

Based on market developments over the last decade, one observes that so far the
efficiency camp predominates. However, the amount of venture capital invested
recently in the cost reduction camp suggests that in another 2 to 5 years, once these
startups get some market experience, thin-films may capture more of the market.

Materials Considerations

Since photovoltaics are used to create energy in an environmentally sustainable
manner, it is important to compare the materials used in different types of modules.
PV manufacturing processes are generally of low impact. Crystalline PV cells are
primarily non-toxic silicon, manufacturing process chemicals are carefully reused and
recycled, and the frames are made from common aluminum.

The overall energy payback for crystalline modules is 2 to 4 years—that is, it takes 2
to 4 years for the module to create as much energy as was used in its making—after
which the energy comes free from the sun. Thin-film modules are even better, with
energy paybacks of 1 to 2 years.

There are a few relatively minor but nonetheless significant materials issues to
consider. Some manufacturers use lead-free solder for cell interconnections and some
do not. Some are developing cells containing the extremely toxic element cadmium.
While the concentrations of cadmium used in these modules are supposedly safe, we
recommend against them since they provide no great benefit.

Another issue is the relative scarcity of materials used in the product. Standard
crystalline PV modules use silicon (the second most abundant element in Earth’s
crust) for the cells and glass plus some thin plastic encapsulating materials. Many of
the new thin-film products use rare elements such as indium, gallium, and tellurium.
While there is enough of these materials on earth to make PV modules for several
decades, there certainly is not enough to last much beyond that. While the scarcity of
rare elements in 20 years doesn’t have a major impact on buying decisions today, it
does lower our confidence in the sustainability of the manufacturing enterprise and
the validity of a 20 year warranty.

Balance of System Equipment

Besides the PV modules, system equipment includes inverters, mounting equipment,
switchgear, conduit, wire, and monitoring equipment. Once the module has been
selected, the balance of system equipment is designed and specified. Proper array
stringing, matching of inverters with modules, wire sizing, and electrical
interconnection are worked out during design development. Proper design can result
in power production increases and shorter payback time.
Mounting

Standard module roof mounting hardware comes in two general categories: penetrating systems and non-penetrating systems. Some non-penetrating systems may be modified to include a few penetrations for seismic stability depending on building structure and code requirements. Generally, flat roofs need no or few penetrations, and sloped roofs need penetrating mountings systems which connect the PV module strut system directly to building rafters or purlins.

Modules on flat roofs are either horizontal or sloped to the recommended site maximum. Modules on sloped roofs are typically oriented along the roof for aesthetic reasons, though it is not uncommon to tilt them if not facing south. Modules on separate structures can be sloped to the recommended site maximum. Depending on the system, the total roof load of modules plus mounting hardware is around 2 to 4 pounds per square foot.

If the roofs on the Diamond PE Center, Pomo 1, and Pomo 2 are replaced, we recommend installing mounting brackets beneath new roofing so it doesn’t need to be disturbed later.

Price Trends

The PV industry generally uses dollars per watt for discussing prices. However, it is important to clarify the kind of watts being discussed. Some PV contractors and incentive programs use the term “AC Watts” or $/wAC, viewing the system from the AC side. Since this number varies due to the design factors specific to each job and as incentive programs come and go, in this report we use the more common convention of defining watts as the nameplate DC wattage measured at standard test conditions for the module in question.

Typical subcontractor prices for PV systems installed in 2006 similar to those analyzed in this report were around $7 to $8/watt, of which 70% is for modules, 15% for balance of system equipment, and 15% for labor. This excludes incentives, rebates, design fees, general contractor costs or design-build markups, battery backup systems, and special standalone mounting systems.

While installed costs have been generally dropping for the past 30 years, they rose slightly in 2006 due to a worldwide shortage of processed silicon. Though there is plenty of silicon on earth, the bottleneck has been in processing the raw material pure enough for PV cells and computer chips. A number of silicon manufacturing facilities are currently being built, and most industry experts agree that silicon prices will start dropping again in 1 to 3 years. Because most large manufacturers have secured long-term supply contracts, it is unlikely that there will be any major increases between now and then, though slight rises may occur.
Competition between local vendors also affects installed cost. Although the industry is growing rapidly (about 40% per year), it is quite competitive, and bids are typically within 10% of each other. The high growth rate also encourages new PV contracting companies to "buy" a project by bidding substantially under the market rate and intentionally lose money. This sometimes leads to disputes during construction and difficulties in enforcing warranties. Caution should be used if a bid seems particularly low.

Rebates and Incentives

California Solar Initiative
As of January 1, 2007, the California Solar Initiative (CSI) Performance Based Incentives (PBI) for solar energy systems larger than 100 kilowatts will be paid monthly based on actual energy produced for a period of five years commencing after installation, commissioning, and approval of rebate claim submissions.

CSI incentive levels will automatically decrease in 10 steps based on the number of systems installed under the program. The table below indicates that, for example, until 70 megawatts have been installed statewide, non-taxable entities such as the College of Marin will receive $0.50 per kWh produced. The incentive then drops to $0.46 per kWh until 100 MW have been installed. Once approved, the incentive will remain constant over the payout period. Commercial applicants receive a lower incentive than non-taxable entities, but they may qualify for a 30% federal tax credit.

TABLE 1: CSI PBI Schedule for Systems 100kW and Larger

<table>
<thead>
<tr>
<th>Step</th>
<th>Megawatts Per Step</th>
<th>Commercial Rate ($/kWh)</th>
<th>Non-Taxable Rate ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>50</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>2</td>
<td>70</td>
<td>$0.39</td>
<td>$0.50</td>
</tr>
<tr>
<td>3</td>
<td>100</td>
<td>$0.34</td>
<td>$0.46</td>
</tr>
<tr>
<td>4</td>
<td>130</td>
<td>$0.26</td>
<td>$0.37</td>
</tr>
<tr>
<td>5</td>
<td>160</td>
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</tr>
<tr>
<td>6</td>
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<td>$0.26</td>
</tr>
<tr>
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<td>215</td>
<td>$0.09</td>
<td>$0.19</td>
</tr>
<tr>
<td>8</td>
<td>250</td>
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<tr>
<td>9</td>
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</tr>
<tr>
<td>10</td>
<td>250</td>
<td>$0.03</td>
<td>$0.10</td>
</tr>
</tbody>
</table>

Given that that incentive levels will drop, it is advisable to reserve a rebate as close as possible to 18 months before the projected final inspection date. A reservation applied for too soon could expire and force the College to reapply at the then current rate. Waiting too long could mean that incentive levels have dropped so much that the economics are no longer as attractive.

CSI System Size Limits
PV systems up to 5 MW may qualify for the CSI program, although systems larger than 1 MW will be prorated based on the ratio of 1 MW to the system size. The rebate for a 5 MW system would be based on 1/5 of the system output. The applicant may, at its own expense, separately meter a 1 MW element of a larger system.

Host Customers such as the College of Marin can receive up to 1 MW of maximum incentive funding from the CSI program for a single “site” for the duration of the program. The CSI Handbook has an error in the definition of site, so the number of sites at the College is currently unclear. This definition will likely be clarified within a few months.

For existing buildings, the PV system size must be based upon the previous 12 months usage. For new buildings, an engineering estimate of 12 months electrical consumption must be provided. If the PV systems generate more electricity than the buildings consume over the course of one year, neither the CSI program nor PG&E will pay or roll credit to the next year for the excess generation.

**CSI Energy Efficiency Requirements**

The program is currently evaluating requirements for energy efficiency audits and performance levels. The proposed requirement states that energy efficiency audits are required but the Host Customer does not have to implement the energy efficiency recommendations in order to receive a rebate. We expect this requirement will be clarified within a few months.

**CSI Permanence, Warranty, and Insurance Requirements**

The program is for permanently installed systems, with 10 year warranty periods. The Host Customer and any third-party owners must maintain commercial general liability insurance for the term of the CSI contract at levels of $2M for each occurrence. There are also Worker’s Compensation, business automobile, and PV system installer insurance requirements.

**CSI Application Process**

See Appendix D for the CSI application process.

**CSI Application Fee**

An application fee of 1 percent of the unadjusted requested CSI program incentive amount is required, but it is returned to the Host Customer upon verification of the completed PV system installation.

**Tax Credits**

There are currently no state solar tax incentives.

If an owner is a taxable entity, it may qualify for a 30% federal tax credit on net PV system costs. However, the CSI incentive will be applied at the lower commercial levels. The College may consider third-party ownership of the PV systems (see...
below) but should be aware that the CSI’s two-tiered incentive program may make third-party arrangements less attractive.

**PG&E Savings by Design**  
This program rewards energy efficient design and should be pursued, but does not offer rebates or incentives for solar-based systems.

**PG&E Customized Energy Efficiency / Demand Response Initiative**  
This program is similar to Savings by Design.

**PG&E Solar Schools Program**  
The PG&E Solar Schools Program is for underserved K–12 schools.

**California Emerging Renewables Rebate Program**  
This program is no longer available for PV systems as of January 1, 2007.

**California Self-Generating Incentive Program (SGIP)**  
This program is no longer available for PV systems as of January 1, 2007.

**Financing Options**  
If the College wishes to reduce capital outlay, some financing options may be available. In addition to a straight bank loan, two third-party ownership options which have become available in the last year.

- **Straight Equipment Lease:** The third party installs a system and leases it to the College for typically 7 years, at which time the College buys out the lease. The College owns the system and pays only the lease payments. The College may be able to receive federal tax credits routed through the for-profit entity.

- **Power Purchase Agreement:** The third party installs and owns the system, and sells the College electricity at an agreed upon rate for 7 years, at which time the College buys the system. The College may be able to receive federal tax credits routed through the for-profit entity.

Third-party options require careful legal, tax, and accounting scrutiny. If the performance efficiency is high enough, they may help install systems with lower initial capital outlay at the expense of operating savings.

**Site Analysis**

Each existing building roof or future building site was measured with a digital sunpath tool to determine shading losses. Orientation, obstructions, roof composition, and other relevant factors were noted. Shadows cast onto a single PV module can substantially reduce the output of all modules in that series string. Modules are laid out to minimize shading losses on each string, and obstructions are removed when possible. All trees which caused measurable shading were given a number so that
tree trimming recommendations can be made. Shading issues caused by adjacent buildings were also noted.

Appendix A includes a detailed description of each building.

Appendix B includes typical shade measurements for each building. They are not complete readings (65 shots were taken for use in the simulation models), but a sample from each building depicting a typical shading profile.

**Electrical Systems**

**Electrical Load Analysis**

ATCG provided estimates of power consumption and PG&E rate schedules for seven buildings after construction or remodeling. High Sun estimated daily costs for use in calculating savings and payback periods. A more accurate prediction would require a detailed hourly analysis, which may not be useful since assumptions about energy cost escalation are less than 10%. Table C-1 in Appendix C includes projected electrical energy load and cost.

**Utility Interconnection**

There are a number of ways that PV systems can be interconnected with the grid. The selected PV equipment will influence design of the bussing and main breaker at the service entrance. Switchgear must be located within 50 feet of the PG&E meter.

Grid connected PV systems require application to and approval by the local utility prior to operation. In the last year or so PG&E has substantially tightened its interconnection standards regarding transformer sizing. Their requirement for a larger transformer with a PV system is being questioned in the courts by customers concerned that their cost for transformer upgrades is unfairly benefiting PG&E.

We recommend application to PG&E as soon as the first PV drawings are released in order to begin discussions with them and size transformers accordingly.

**PV System Options**

Based on the load, building, and site parameters, we developed conceptual PV system designs for each of the seven buildings surveyed. Relevant parameters were entered into an hourly computer simulation model to determine the maximum PV energy production potential of each building. Additional models were then created to look at different options.

There are two primary metrics by which PV systems are typically measured: total energy production and energy production efficiency, which determines cost effectiveness. Generally speaking, when the area is limited, increasing total energy...
production beyond the point of maximum production efficiency reduces production efficiency and cost effectiveness. Tilting modules up to increase production efficiency requires spreading them into rows and preventing one row from shading the next. The space between the rows means fewer modules, which reduces total production.

Production efficiency is expressed as the ratio of PV energy production (kWh/day) to kW of PV. Based on the weather data for Marin County, the maximum ratio for a PV module with ideal orientation and tilt and no shade is 3.7.

**Option 1**
The highest efficiency crystalline PV modules available are mounted flat and in the same plane on the roofs. This maximizes power production from the limited space. Three of the buildings do not have enough roof space to provide 50% of the building load and two have enough for only 49%. Diamond PE has enough space for more than 50% but for consistency it is calculated at 50%.

Note that structural upgrades to Diamond PE’s roof would be needed to support the weight of the modules; we assume that they will be mounted on separate free-standing structures such as parking lot trellises.

It is not known at this time of the roofs of Pomo 1 and Pomo 2 can bear the weight of crystalline modules.

**Option 2**
This is the same as Option 1 but the modules are tilted up 24 degrees to the south. This maximizes production efficiency, but because the modules are spaced into rows to avoid shading, there are fewer and total power decreases. This option demonstrates an increase of economic efficiency (lower payback period) at the expense of lower total power production.

For simplification of the analysis, this option assumes that the modules on all buildings are tilted toward the south. Performing Arts, Fine Arts, and Science/Math/Central Plant face some 45 degrees from south, so tilting modules on these roofs to the south may increase mounting complexity to bring the rows into line with the building.

Note that results for Pomo 1 and 2 are the same as for Option 1 because the existing roof slope is close to ideal.

**Option 3**
This option is the same as Option 1 except that module area sufficient to meet 50% of the load has been calculated. This assumes that the additional surface area will be created nearby by adding a separate ground or parking lot array sloped 10 degrees to the south.
**Option 4**
The Diamond PE Center is modeled to meet 50% of load except that thin-film modules instead of crystalline modules are used. Note that module area almost triples due to lower power efficiency, but the weight limitations of the roof are not exceeded.

Resulting PV areas, power production, percent of building load, and production efficiency for the 4 options are found in Tables C-2 to C-5 in Appendix C.

Table C-6 in Appendix C presents the costs of all the options. Table C-7 presents the costs of the recommended options in order to meet 50% of load: Thin-film modules on the roof of Diamond PE, and crystalline on the roofs and separate structures of the other buildings.

**Comments on the Results**

**Diamond PE Center**
Of all the buildings surveyed, the PE Complex has the highest ratio of available roof area to electrical load. Unfortunately, crystalline PV modules cannot be roof-mounted due to their weight. Options 1, 2, and 3 assume that separate free-standing structures such as parking lot trellises support the modules; they are included in the costs in Tables C-6 and C-7.

Option 4 shows that 50% of the load can be met with thin-film modules, whose weight can be supported by the existing structure. The rest of the roof is available for thermal swimming pool heating panels.

**Performing Arts**
Since this analysis has been for maximum power production, we have modeled PV modules as close to the tower as possible while maintaining a shading loss of 45%. During design development, we will investigate moving them away from the tower a bit to keep shading loss at 20% to 25%, which will better balance economic efficiency and total campus load reduction.

A comparison of Options 1 and 2 indicates that an 11% increase in production efficiency reduces payback time from 31 to 29 years but produces 44% less power for a 53% lower installed cost. There are fewer modules but they are better oriented.

**Science/Math/Central Plant**
The low 23% ratio of energy production to need is due to more space relative to roof area (3 stories) and higher laboratory equipment loads.

**Fine Arts**
The redwood grove reduces overall production efficiency compared to the other buildings.

**IVC Main**
This building has the lowest shading loss and therefore the highest production efficiency with tilted modules, which, however, produce only 27% of load. Using a flat mount increases production to 49%.

**IVC Pomo 1 and 2**

Pomo 1 has slightly less shading than Pomo 2 and thus slightly better production efficiency. Excellent orientation and roof pitch allow higher production efficiencies from these two buildings without additional tilting.

**Environmental Payback**

While the economic payback on a photovoltaic system is good, the environmental payback is enormous. Conventional fossil fuel power plants pollute more than any other single US industry.

The 1.6 megawatts produced over Option 1’s expected 30 year lifetime will avoid the consumption of 8,600,000 gallons of oil or 55,000 tons of coal. The systems will prevent 65,000 tons of carbon dioxide pollution, 1,000,000 pounds of sulfur dioxide pollution, 500,000 pounds of nitrous oxides pollution, and prevent radioactive waste (21% of 2004 PG&E power came from nuclear plants). The environmental benefit of a PV system is greater than any other single action that could be taken at the College of Marin.
Appendix A
Site Analysis

Diamond PE Center

There are three roofs: East roof, upper (gym) roof, and west roof. All surfaces are flat or gently sloped (some with a central ridge) and suitable for surface mounting PV modules either flat or tilted up in rows.

However, additional weight on the upper roof cannot exceed 2 pounds/square foot. Crystalline PV modules weigh from 2 to 4 pounds/square foot. The roofs will support thin-film PV and thermal modules.

Shade Measurements
The average loss due to shading for this building is 5%. The west roof has very little shading. The east roof has some shading due to the pop-up. Both east and west have small amounts of shading due to the maple trees. Shading should be addressed during design development.

Orientation
The building orientation is due south and the roof is flat.

Performing Arts

There are three roofs: Lower roof (which wraps around 3 sides of the tall portion), center roof, and upper roof. All surfaces are flat or gently sloped and suitable for surface mounting PV modules either flat or tilted up in rows.

While the upper roof does have a small area available for PV modules, it may be wise consider their installation as a bid alternate due to the extra expense of craning or hand carrying modules up through the building. Note also that the upper roof has a 3 foot parapet so an array would need a slightly more expensive elevated mounting system.

Shade Measurements
The average loss due to shading for this building is 14%. The SW lower roof has good solar access, but shading increases as you move around the roof and start to approach the north side of the tower.

Orientation
The building orientation is 45 degrees east of south and the roof is flat.

Science/Math/Central Plant
Roof plans are not yet detailed enough to determine specific PV mounting locations. We assumed an approximate area of flat roof based on the site plan for surface mounting PV modules either flat or tilted up in rows.

**Shade Measurements**
The average loss due to shading for this building is 5%. There are only a few trees to the SE which cause minor shading.

**Orientation**
The building orientation is 45 degrees east of south and the roof is flat.

**Fine Arts**

Roof plans are not yet detailed enough to determine specific PV mounting locations. We assumed an approximate area of flat roof based on the site plan for surface mounting PV modules either flat or tilted up in rows.

**Shade Measurements**
The average loss due to shading for this building is 24%. It is situated to the north of a redwood grove which we assume will not be trimmed.

**Orientation**
The building orientation is 45 degrees east of south and the roof is flat.

**IVC Main**

Roof plans are not yet detailed enough to determine specific PV mounting locations. We assumed an approximate area of flat roof based on the site plan for surface mounting PV modules either flat or tilted up in rows.

**Shade Measurements**
The average loss due to shading for this building is 3%. The only, minor issue is a large and beautiful madrone to the south which we assume will not be trimmed.

**Orientation**
The building orientation is 17 degrees east of south and the roof is flat.

**IVC Pomo 1**

We have not seen roof plans detailed enough to determine specific PV mounting locations. We assumed that the area, slope, and orientation will be the same as the current building and that the entire south facing roof could be covered in PV modules.

**Shade Measurements**
The average loss due to shading for this building is 7%, caused primarily by oaks to the west.
Orientation
The building orientation is 17 degrees west of south and the roof is sloped 5:12.

IVC Pomo 2

We have not seen roof plans detailed enough to determine specific PV mounting locations. We assumed that the area, slope, and orientation will be the same as the current building and that the entire south facing roof could be covered in PV modules.

Shade Measurements
The average loss due to shading for this building is 5%, caused primarily by oaks to the east.

Orientation
The building orientation is 17 degrees west of south and the roof is sloped 5:12.
Appendix B
Digital Sunpath Diagrams

Average Annual Solar Access
Representative Diagrams for Each Building
Diamond PE Center
95% Average Annual Solar Access

Solar Access: Annual: 96% -- Summer (May-Oct): 96% -- Winter (Nov-Apr): 95%

Data by Solmetric SunEye™ -- www.solmetric.com

Monthly Solar Access

January 22, 2007
Performing Arts
86% Average Annual Solar Access

Solar Access:
Annual: 92% -- Summer (May-Oct): 96% -- Winter (Nov-Apr): 88%

Monthly Solar Access

<table>
<thead>
<tr>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
</tr>
</thead>
<tbody>
<tr>
<td>81%</td>
<td>84%</td>
<td>95%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
<td>91%</td>
<td>80%</td>
<td>82%</td>
</tr>
</tbody>
</table>

Data by Solmetric SunEye™ -- www.solmetric.com
Science/Math/Central Plant

95% Average Annual Solar Access

Sky01 -- 12/07/06 16:25 -- 26' HIGH READING
Solar Access: Annual: 95% -- Summer (May-Oct): 99% -- Winter (Nov-Apr): 91%
Fine Arts
76% Average Annual Solar Access

Sky01 -- 12/07/06 16:02 -- 4' HIGH READING
Solar Access: Annual: 79% -- Summer (May-Oct): 86% -- Winter (Nov-Apr): 70%

Monthly Solar Access

Data by Solmetric SunEye™ -- www.solmetric.com
IVC Main

97% Average Annual Solar Access

Sky08 -- 12/14/06 10:27

Data by Solmetric SunEye™ -- www.solmetric.com
Pomo 1 (Auto Shop Building)
93% Average Annual Solar Access

Sky17 -- 12/14/06 11:04
Solar Access: Annual: 95% -- Summer (May-Oct): 98% -- Winter (Nov-Apr): 90%

Data by Solmetric SunEye™ -- www.solmetric.com
Pomo 2 (Transportation/Auto Tech Lab)
93% Average Annual Solar Access

Sky14 -- 12/14/06 10:55

Data by Solmetric SunEye™ -- www.solmetric.com
### TABLE C-1: Projected Electrical Energy Load and Cost

<table>
<thead>
<tr>
<th>Building</th>
<th>Roof Area (sf)</th>
<th>Est Future Load (kWh/day)</th>
<th>Rate</th>
<th>Avg Energy Cost ($/kWh)</th>
<th>Avg Energy Cost ($/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diamond PE Center</td>
<td>48,320</td>
<td>1,569</td>
<td>A10S</td>
<td>$0.12</td>
<td>$188.28</td>
</tr>
<tr>
<td>Performing Arts</td>
<td>29,000</td>
<td>2,153</td>
<td>E20P</td>
<td>$0.09</td>
<td>$193.77</td>
</tr>
<tr>
<td>Science/Math/Central Plant</td>
<td>20,000</td>
<td>4,448</td>
<td>E20P</td>
<td>$0.09</td>
<td>$400.32</td>
</tr>
<tr>
<td>Fine Arts</td>
<td>15,000</td>
<td>1,644</td>
<td>E20P</td>
<td>$0.09</td>
<td>$147.96</td>
</tr>
<tr>
<td>IVC Main</td>
<td>17,600</td>
<td>1,928</td>
<td>SE19P</td>
<td>$0.10</td>
<td>$192.80</td>
</tr>
<tr>
<td>Pomo 1 (Auto Shop Building)</td>
<td>3,375</td>
<td>438</td>
<td>SE19P</td>
<td>$0.10</td>
<td>$43.80</td>
</tr>
<tr>
<td>Pomo 2 (Transportation/Auto Tech Lab)</td>
<td>5,960</td>
<td>549</td>
<td>SE19P</td>
<td>$0.10</td>
<td>$54.90</td>
</tr>
</tbody>
</table>

Note: Average energy cost data approximates (±10% accuracy) PG&E’s rate schedules and the correlation between the hourly power production of the PV system and the time-of-use/seasonal rate structure. Service and demand charges are not included since PV rarely eliminates demand charges, and service charges are fixed regardless of kWh usage.

### TABLE C-2: PV Option 1 – Max Production on Roof up to 50% of Load (Crystalline)

<table>
<thead>
<tr>
<th>Building</th>
<th>Available Roof Area (sf)</th>
<th>Needed PV Area (sf)</th>
<th>Installed PV kW</th>
<th>Est Future Load (kWh/d)</th>
<th>PV (kWh/d)</th>
<th>PV % of Load</th>
<th>Production Efficiency (kWh/d)/kW</th>
<th>Production Efficiency % of Ideal</th>
</tr>
</thead>
<tbody>
<tr>
<td>PE</td>
<td>43,488*</td>
<td>13,734</td>
<td>245.07</td>
<td>1,569</td>
<td>785</td>
<td>50%</td>
<td>3.202</td>
<td>87%</td>
</tr>
<tr>
<td>PA</td>
<td>20,848</td>
<td>20,848</td>
<td>372.02</td>
<td>2,153</td>
<td>1,063</td>
<td>49%</td>
<td>2.858</td>
<td>77%</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>18,536</td>
<td>18,536</td>
<td>330.75</td>
<td>4,448</td>
<td>1,044</td>
<td>23%</td>
<td>3.155</td>
<td>86%</td>
</tr>
<tr>
<td>FA</td>
<td>13,346</td>
<td>13,346</td>
<td>238.14</td>
<td>1,644</td>
<td>604</td>
<td>37%</td>
<td>2.535</td>
<td>69%</td>
</tr>
<tr>
<td>IVC Main</td>
<td>16,528</td>
<td>16,523</td>
<td>294.84</td>
<td>1,928</td>
<td>950</td>
<td>49%</td>
<td>3.220</td>
<td>87%</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>2,966*</td>
<td>2,966</td>
<td>52.92</td>
<td>438</td>
<td>181</td>
<td>41%</td>
<td>3.429</td>
<td>93%</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>5,190*</td>
<td>5,190</td>
<td>79.70</td>
<td>549</td>
<td>272</td>
<td>50%</td>
<td>3.414</td>
<td>93%</td>
</tr>
</tbody>
</table>

Note: Diamond PE structure will not support weight of crystalline PV, and Pomo 1 and Pomo 2 may not.
### TABLE C-3: PV Option 2 – Maximum Production Efficiency on Roof (Crystalline)

<table>
<thead>
<tr>
<th>Building</th>
<th>Available Roof Area (sf)</th>
<th>Needed PV Area (sf)</th>
<th>Installed PV kW</th>
<th>Est Future Load (kWh/d)</th>
<th>PV (kWh/d)</th>
<th>PV % of Load</th>
<th>Production Efficiency (kWh/d)/kW</th>
<th>Production Efficiency % of Ideal</th>
</tr>
</thead>
<tbody>
<tr>
<td>PE</td>
<td>43,488*</td>
<td>12,633</td>
<td>225.41</td>
<td>1,569</td>
<td>786</td>
<td>50%</td>
<td>3.487</td>
<td>95%</td>
</tr>
<tr>
<td>PA</td>
<td>20,848</td>
<td>10,424</td>
<td>186.01</td>
<td>2,153</td>
<td>590</td>
<td>27%</td>
<td>3.172</td>
<td>86%</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>18,536</td>
<td>9,268</td>
<td>165.38</td>
<td>4,448</td>
<td>577</td>
<td>13%</td>
<td>3.487</td>
<td>95%</td>
</tr>
<tr>
<td>FA</td>
<td>13,346</td>
<td>6,673</td>
<td>119.07</td>
<td>1,644</td>
<td>335</td>
<td>20%</td>
<td>2.814</td>
<td>76%</td>
</tr>
<tr>
<td>IVC Main</td>
<td>16,528</td>
<td>8,262</td>
<td>147.42</td>
<td>1,928</td>
<td>527</td>
<td>27%</td>
<td>3.575</td>
<td>97%</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>2,966*</td>
<td>2,966</td>
<td>52.92</td>
<td>438</td>
<td>181</td>
<td>41%</td>
<td>3.429</td>
<td>93%</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>5,190*</td>
<td>5,190</td>
<td>79.70</td>
<td>549</td>
<td>272</td>
<td>50%</td>
<td>3.414</td>
<td>93%</td>
</tr>
</tbody>
</table>

Note: Diamond PE structure will not support weight of crystalline PV, and Pomo 1 and Pomo 2 may not.

### TABLE C-4: PV Option 3 – 50% Load Production (Crystalline)

<table>
<thead>
<tr>
<th>Building</th>
<th>Available Roof Area (sf)</th>
<th>Needed PV Area (sf)</th>
<th>Installed PV kW</th>
<th>Est Future Load (kWh/d)</th>
<th>PV (kWh/d)</th>
<th>PV % of Load</th>
<th>Production Efficiency (kWh/d)/kW</th>
<th>Production Efficiency % of Ideal</th>
</tr>
</thead>
<tbody>
<tr>
<td>PE</td>
<td>43,488*</td>
<td>13,734</td>
<td>245.07</td>
<td>1,569</td>
<td>785</td>
<td>50%</td>
<td>3.202</td>
<td>87%</td>
</tr>
<tr>
<td>PA</td>
<td>20,848</td>
<td>21,177</td>
<td>376.72</td>
<td>2,153</td>
<td>1,077</td>
<td>50%</td>
<td>2.860</td>
<td>77%</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>18,536</td>
<td>43,677</td>
<td>689.60</td>
<td>4,448</td>
<td>2,224</td>
<td>50%</td>
<td>3.224</td>
<td>88%</td>
</tr>
<tr>
<td>FA</td>
<td>13,346</td>
<td>19,126</td>
<td>320.65</td>
<td>1,644</td>
<td>822</td>
<td>50%</td>
<td>2.563</td>
<td>70%</td>
</tr>
<tr>
<td>IVC Main</td>
<td>16,528</td>
<td>16,815</td>
<td>298.91</td>
<td>1,928</td>
<td>964</td>
<td>50%</td>
<td>3.223</td>
<td>87%</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>2,966*</td>
<td>3,589</td>
<td>64.00</td>
<td>438</td>
<td>219</td>
<td>50%</td>
<td>3.429</td>
<td>93%</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>5,190*</td>
<td>5,190</td>
<td>79.70</td>
<td>549</td>
<td>272</td>
<td>50%</td>
<td>3.414</td>
<td>93%</td>
</tr>
</tbody>
</table>

Note: Diamond PE structure will not support weight of crystalline PV, and Pomo 1 and Pomo 2 may not.

### TABLE C-5: PV Option 4 – Diamond PE Center with Thin-Film Modules

<table>
<thead>
<tr>
<th>Building</th>
<th>Available Roof Area (sf)</th>
<th>Needed PV Area (sf)</th>
<th>Installed PV kW</th>
<th>Est Future Load (kWh/d)</th>
<th>PV (kWh/d)</th>
<th>PV % of Load</th>
<th>Production Efficiency (kWh/d)/kW</th>
<th>Production Efficiency % of Ideal</th>
</tr>
</thead>
<tbody>
<tr>
<td>PE</td>
<td>48,320</td>
<td>37,954</td>
<td>222.85</td>
<td>1,569</td>
<td>780</td>
<td>50%</td>
<td>3.498</td>
<td>84%</td>
</tr>
</tbody>
</table>
### TABLE C-6: Financial Analysis Summary

<table>
<thead>
<tr>
<th>Building</th>
<th>Installed Cost</th>
<th>Incentive</th>
<th>Net Cost</th>
<th>Payback Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum Production on Roof up to 50% of Load (Crystalline)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PE</td>
<td>$4,559,952</td>
<td>$368,717</td>
<td>$4,191,235</td>
<td>80</td>
</tr>
<tr>
<td>PA</td>
<td>$4,837,485</td>
<td>$499,518</td>
<td>$4,337,967</td>
<td>66</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>$4,300,897</td>
<td>$490,565</td>
<td>$3,810,332</td>
<td>62</td>
</tr>
<tr>
<td>FA</td>
<td>$3,096,646</td>
<td>$283,636</td>
<td>$2,813,010</td>
<td>67</td>
</tr>
<tr>
<td>IVC Main</td>
<td>$3,833,942</td>
<td>$446,284</td>
<td>$3,387,658</td>
<td>56</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>$688,143</td>
<td>$85,031</td>
<td>$603,112</td>
<td>55</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>$1,036,311</td>
<td>$127,784</td>
<td>$908,527</td>
<td>55</td>
</tr>
<tr>
<td><strong>Maximum Production Efficiency on Roof (Crystalline)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PE</td>
<td>$4,194,280</td>
<td>$369,284</td>
<td>$3,824,996</td>
<td>76</td>
</tr>
<tr>
<td>PA</td>
<td>$2,420,790</td>
<td>$277,164</td>
<td>$2,143,626</td>
<td>64</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>$2,150,448</td>
<td>$258,847</td>
<td>$1,891,601</td>
<td>61</td>
</tr>
<tr>
<td>FA</td>
<td>$1,548,323</td>
<td>$157,337</td>
<td>$1,390,986</td>
<td>66</td>
</tr>
<tr>
<td>IVC Main</td>
<td>$1,916,971</td>
<td>$247,640</td>
<td>$1,669,331</td>
<td>54</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>$688,143</td>
<td>$85,031</td>
<td>$603,112</td>
<td>55</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>$1,036,311</td>
<td>$127,784</td>
<td>$908,527</td>
<td>55</td>
</tr>
<tr>
<td><strong>50% Load Production (Crystalline)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PE</td>
<td>$4,559,952</td>
<td>$368,717</td>
<td>$4,191,235</td>
<td>80</td>
</tr>
<tr>
<td>PA</td>
<td>$4,939,057</td>
<td>$505,832</td>
<td>$4,433,225</td>
<td>68</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>$12,056,561</td>
<td>$1,044,500</td>
<td>$11,012,061</td>
<td>87</td>
</tr>
<tr>
<td>FA</td>
<td>$4,879,787</td>
<td>$386,229</td>
<td>$4,493,558</td>
<td>81</td>
</tr>
<tr>
<td>IVC Main</td>
<td>$3,922,700</td>
<td>$452,739</td>
<td>$3,469,961</td>
<td>58</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>$908,733</td>
<td>$102,829</td>
<td>$805,903</td>
<td>62</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>$1,036,311</td>
<td>$127,784</td>
<td>$908,527</td>
<td>55</td>
</tr>
<tr>
<td><strong>Diamond PE Center with Thin-Film Modules</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PE</td>
<td>$2,778,479</td>
<td>$366,490</td>
<td>$2,411,989</td>
<td>47</td>
</tr>
</tbody>
</table>

**Notes:**

1. The payback calculations include a 6% fuel escalation factor, derived from current DOE discount and inflation rates.
2. Current PG&E rate schedules for each building were used.
3. Incentives were calculated from CSI non-taxable entity levels of $0.26/kWh over 5 years.
4. Costs include 10% general conditions, 5% overhead and profit, 8%/year escalation for 3 years (except for 2 years for Diamond PE), and 30% soft costs.
5. Options 1, 2, and 3 for Diamond PE include separate free-standing structures such as parking lot trellises. Likewise, Option 3 for other buildings that do not have enough roof space for 50% production includes the cost of separate structures for the additional PV space needed to reach 50%.
### TABLE C-7: Financial Analysis Summary of Recommended Options for 50% Load

<table>
<thead>
<tr>
<th>Building</th>
<th>Installed Cost</th>
<th>Incentive</th>
<th>Net Cost</th>
<th>Payback Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>PE</td>
<td>$2,778,479</td>
<td>$366,490</td>
<td>$2,411,989</td>
<td>47</td>
</tr>
<tr>
<td>PA</td>
<td>$4,939,057</td>
<td>$505,832</td>
<td>$4,433,225</td>
<td>68</td>
</tr>
<tr>
<td>S/M/CP</td>
<td>$12,056,561</td>
<td>$1,044,500</td>
<td>$11,012,061</td>
<td>87</td>
</tr>
<tr>
<td>FA</td>
<td>$4,879,787</td>
<td>$386,229</td>
<td>$4,493,558</td>
<td>81</td>
</tr>
<tr>
<td>IVC Main</td>
<td>$3,922,700</td>
<td>$452,739</td>
<td>$3,469,961</td>
<td>58</td>
</tr>
<tr>
<td>Pomo 1</td>
<td>$908,733</td>
<td>$102,829</td>
<td>$805,903</td>
<td>62</td>
</tr>
<tr>
<td>Pomo 2</td>
<td>$1,036,311</td>
<td>$127,784</td>
<td>$908,527</td>
<td>55</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$30,521,628</td>
<td>$2,986,403</td>
<td>$27,535,224</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
1. Diamond PE is thin-film; the rest are crystalline.
Appendix D
California Solar Initiative (CSI)
Application Process

The overall application process is as follows.

- Design the systems, produce bid documents (not necessarily final construction documents), select PV contractor and obtain a letter of intent (not necessarily the final signed contract).
- Send in Reservation Request package with items listed under Step 1.
- Finish construction documents, finalize contract with PV contractor, and send in all items under Step 2.
- Install systems within 18 months of reservation issue (some 2 to 6 weeks after applying, unless there is a waiting list).
- Once systems have final building permit and PG&E interconnection sign-off, send in all items under Step 3 and wait 30 days for first rebate check.

3-Step Application Process – Forms and Documentation Requirements

**Step 1: Reservation Request**
Reservation Request Application Checklist
Reservation Request Application with Original Signature
Proof of Electric Utility Service for Site
System Description Worksheet
Electrical System Sizing Documentation
Incentive Calculation Worksheet & EPBB Documentation
Description of other Funding Sources (If applicable)
Evidence of Executed Agreement of System Purchase
Application Fee
Certification of tax-exempt status and AB1407 compliance (Government, Non-profit, and Public Entities only)

**Step 2: Proof of Project Milestone**
Completed Proof of Project Milestone Checklist
Host Customer Certificate of Insurance
System Owner Certificate of Insurance (if different than Host Customer)
Copy of Completed Interconnection Application
Copy of executed contract for system installation
Copy of executed alternative System Ownership agreement (if System Owner is different than Host Customer)
Project Cost Breakdown Worksheet
Revised Sizing Calculations (If applicable)
Revised Incentive Calculation Worksheet (If applicable)
CSI Program Contract with Original Signature
Copy of RFP or solicitation (Government, Non-profit, and Public Entities only)

Step 3: Incentive Form Package
Incentive Claim Checklist
Incentive Claim Form with Original Signatures
Installer/Seller EPBB Field Checklist with Original Signature
Proof of Authorization to Interconnect
Copy of Building Permit and Final Inspection sign-off
Proof of Warranty
Final Project Cost Breakdown Worksheet
Final Project Cost Affidavit
Final Incentive Calculation Worksheet
Revised Sizing Calculations (if applicable)
Payee Data Record
Appendix E
Solar Thermal Systems
Diamond PE Center

General

6,000 to 7,000 square feet of solar water heating collectors will be needed to heat the swimming pools to 80.5°F, assuming 15 hrs/day usage and very little shading on the pool. This estimate assumes the use of a pool cover during off-hours.

In California, solar pool heating systems are usually sized to provide 75 to 100% of the heating requirements from May to September, and to supplement heating the rest of the year, when solar heating is much less efficient. A 6,000 to 7,000 sf solar pool heating system will reduce natural gas consumption for supplemental heating by some 40%, with a payback period of about 5 years. A larger system would waste capacity in the summer for relatively small heating gains in the winter.

We recommend that the system be dedicated to swimming pool heating and not combined with the domestic water heating. Pool heating is very efficient because it is a low temperature application and the pool water runs directly in the solar collectors. Domestic water heating requires a heat exchanger, with its attendant losses.

Mounting the collectors horizontally on the flat roof is only 2% to 5% less efficient than tilting them on racks, and better uses the space by avoiding rack-to-rack shading.

Collector Types

The most common pool heating collectors are unglazed, stabilized polymer collectors such as those manufactured by Heliocol and Fafco. They are durable and relatively inexpensive. Since there is no glass to reflect or inhibit solar gain, they are very efficient heat exchangers, particularly suitable for low-temperature applications like swimming pools, where the high-temperature capabilities of glazed or evacuated tube collectors are not needed. Warranty periods usually 12 years, though the collectors will last 15 years or more.

Glaized flat plate collectors, such as those manufactured by Heliodyne and SunEarth, have copper absorbers and glass covers. Their higher temperature capabilities are well suited for domestic water heating. The cost is about double that of unglazed collectors. They are sometimes used for pool / spa hybrids, or when a rigid, glazed appearance is desired.

Evacuated tube collectors are not often used in California since the sunny conditions allow the use of less expensive unglazed and flat plate collectors. They perform
better than others in cloudier, colder climates and are used in the Pacific Northwest. They can produce very high temperature water well suited for industrial process applications, and are sometimes used for pool heating in less sunny climates or where space is limited. Since they are not common in California and the technology is complex, their cost is high. Manufacturers include Thermomax and Sunda.

Freeze protection should be installed to prevent damage to the system when temperatures fall below 40°. The system is automatically drained before freezing conditions occur and automatically refilled when the temperature rises.

**Rebates and Incentives**

The current federal tax credit for solar water heating does not apply to swimming pool heating systems. PG&E has a Customized Energy Efficiency / Demand Response Incentive program that may offer incentives for efficient pool heating. This will be investigated during design development.

**Cost**

An unglazed, stabilized polymer collector system can be installed for about $300,000. Simple payback will be about 8 years.

**Environmental Payback**

7,000 square feet of solar pool heating collectors will avoid about 140 tons of greenhouse gas emissions.

**Maintenance**

Annual inspection of the circulation system and cleaning the collectors is around $5,000. Pumps, controls, or plumbing fittings may need to be replaced or repaired periodically, at cost of some $4,000 every 5 years.

**Comparison with Photovoltaics**

Although solar pool heating collectors have a shorter payback period than PVs for the Diamond PE Center (5 years versus 17 to 19), they have a shorter lifespan (12 to 15 years versus 30 to 40). Solar thermal systems need much more maintenance and parts replacement due to wear, corrosion, and mineral build-up on pumps, valves, and fittings. Photovoltaics also produce energy more efficiently than solar thermal systems during cold and cloudy weather conditions. The weight of unglazed solar thermal collectors such as Helicol is 1.1 lb/sf versus 2 to 4 lb/sf for PV.