Designing a Photovoltaic Array for Smith College

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Acronyms

AC. . . Alternating current
APS. . . Alternative Energy Portfolio Standards
CSS. . . Community-shared solar
DC. . . Direct current
DOER. . . [Massachusetts] Department of Energy Resources
DPU. . . [Massachusetts] Department of Public Utilities
EEA. . . [Massachusetts] Executive Office of Energy and Environmental Affairs
FERC. . . Federal Energy Regulatory Commission
FY. . . Fiscal year
ISA. . . Interconnection service agreement
ITC. . . Investment Tax Credit
LLC. . . Limited liability corporation
MACRS. . . Modified Accelerated Cost-Recovery System
NMA. . . Net metering agreement
NMF. . . Net metering facility
NREL. . . National Renewable Energy Laboratory
O&M. . . Operation and maintenance
PPA. . . Power purchase agreement
PURPA. . . Public Utility Regulatory Policies Act
PV. . . Photovoltaic(s)
QF. . . Qualifying Facility
REC. . . Renewable Energy Certificate
RPS. . . Renewable Portfolio Standards
SMART. . . Solar Massachusetts Renewable Target [program]
SREC. . . Solar Renewable Energy Certificate
STC. . . Standard test conditions (25°C and 1000 W/m^2)

Symbols

Average values over a certain time period (usually monthly) are indicated by using an overbar, e.g. $\overline{X}$.

A list of the variable and parameter symbols, definitions and units is provided below, any deviations from these units will be explicitly stated in the text:

$A \ldots$ Area (m^2)
$d \ldots$ Depth (m)
$G \ldots$ Radiation/irradiance (W/m^2)
$H \ldots$ Daily insolation ($kWh/m^2/day$)
$h \ldots$ Height (m)
$I \ldots$ Current (A)
$K_T \ldots$ Clearness index
$L \ldots$ Length (m)
$N \ldots$ Integer number
$n \ldots$ Integer number
$P \ldots$ Power (W)
$R_b \ldots$ Direct beam tilt factor
$s \ldots$ Spacing/shadow length (m)
$V \ldots$ Voltage (V)
$w \ldots$ Width (m)
$\beta \ldots$ Tilt angle (° or radians)
$\gamma \ldots$ Surface azimuth angle (° or radians)
$\delta \ldots$ Declination (° or radians)
$\eta \ldots$ Energy efficiency
$\theta \ldots$ Angle of incidence (° or radians)
$\rho \ldots$ Reflectivity (unitless) or resistivity ($\Omega \cdot m$)
$\varphi \ldots$ Latitude (° or radians)
$\omega \ldots$ Hour angle (° or radians)

A list of the subscript and superscript symbols and definitions is provided below:

AC	Alternating current
b	Beam component
d	Diffuse component
DC	Direct current
g	Ground
inv	Inverter
mpp	Maximum power
o	Extraterrestrial
oc	Open circuit
PV	Photovoltaic module
s	Sunrise/sunset
sc	Short circuit or solar constant
T	Tilted surface
z	Zenith

Table of Contents

List of Tables

List of Figures

List of Appendices

Abstract

The development of distributed solar energy is an opportunity for individuals and institutions to support the growth of the clean energy economy, lower their carbon footprint, promote energy security, and potentially save money. This thesis created a decision-making framework for photovoltaic (PV) solar development that focused on the interplay between technical design, stakeholder needs, and constraints. First, stakeholder needs and constraints were assessed and translated into design criteria. Next, eligible sites for solar development were identified and their on-site loads were quantified. Preliminary system layouts were designed for the chosen sites. Capacity and energy production for these arrays was estimated using software modeling and verified with transposition calculations. Optimal combinations of grid connection and financing structure were identified after analyzing regulatory, operational and financial constraints. Finally, design criteria were applied to the arrays and used to determine recommendations for development.

This framework was applied to Smith College as a case study and was based on commercially available technologies and policies in the present and near future. Since Massachusetts is expected to transition to a new solar incentive program next year, both short-term and long-term recommendations were made. A 16 kW_{AC} roof-mounted array on Conway House, the smallest system considered, was recommended for development within the next year. For the long-term, community-shared solar canopies on the parking garage (183 kW_{AC}) and the tennis court parking lots (156 kW_{AC}) were recommended after analyzing feasibility and social, environmental and financial impact, including a life-cycle cost assessment. If both arrays were developed, community-shared solar participants would collectively lower their electricity bills by up to \$168,000 per year and pay the developers \$111,000 per year for installation, operation and maintenance of the system, for combined savings up to \$57,000 per year. Through a sensitivity analysis, it was determined that the lifetime benefits were most sensitive to capital costs and also sensitive to the clearing price of competitive procurement, which has not yet been established. In general, large PV arrays ($\geq$25 kW) connected behind Smith's main meter were not recommended for development because the variability of solar energy would interfere with the smooth operation of the cogeneration plant.

Chapter 1

Introduction and Background

Global climate change is one of the most urgent challenges facing humanity in the 21st century. Combating climate change and promoting a just and sustainable future is central to Smith's mission, evidenced by the values of the Picker Engineering Program,[9] the final report of the Study Group on Climate Change,[10] and the Smith College Strategic Plan.[11] In addition, Smith has many organizations dedicated to the environment and sustainability, including the Environmental Science and Policy Program, the Office of Campus Sustainability, and the Center for the Environment, Ecological Design and Sustainability. Furthermore, former president Carol Christ signed the Carbon Commitment in 2007,[12] and Smith has pledged to become carbon neutral by 2030.[13]

Replacing electricity purchased from the utility with electricity from carbon-neutral sources like solar is critical step towards carbon neutrality. In 2016, Smith's total greenhouse gas emissions were 28,187 metric tons CO_2 equivalent and purchased electricity from the utility accounted for 8.7% of total emissions.[14] Currently 130 solar panels mounted on the Campus Center and more than 1,500 solar panels on the Indoor Track and Tennis facility and Ford Hall produce about 580,000 kWh per year, which is equivalent to about 2% of Smith's annual electricity consumption.[15] [16]

Reducing our carbon footprint is not the only reason why Smith College should invest in solar development. Many individuals are prevented by high capital costs from participating in the renewable energy revolution, and are thus excluded from the benefits of solar energy, which include energy security, self-sufficiency and long-term wealth creation. Smith can help make the benefits of solar energy more accessible to its community by investing in solar development and directly lowering the upfront costs for other participants. In addition, investing in solar energy helps the industry grow and lowers the costs over time as demand increases.

The goals of this thesis were (1) to design a new photovoltaic array located on Smith College property and (2) to propose a model for financing and implementing the design that provides the most benefits to the Smith community within regulatory and operational constraints. This work was based on commercially available technologies as well as markets and regulations in the present and near future.

1.1 Why Photovoltaics?

Solar energy is the most abundant energy source on Earth, yet currently accounts for a small fraction of global energy production. In 2015, total installed solar capacity reached 227 GW and 22 countries had enough capacity to meet more than 1% of their electricity demand. [17] In the United States, however, the disparity is even greater; the United States uses 97.7 quadrillion Btu of energy a year and only 0.9% comes from solar.[18] [19] However, it is necessary to rapidly expand energy production from carbon-neutral sources like solar if we are to transition away from fossil fuels and prevent catastrophic climate change.

In order to avoid the worst impacts of climate change, many nations signed the Copenhagen Accord at the United Nations Framework Convention on Climate Change in 2009, agreeing to limit global mean temperature rise to 2°C above pre-industrial levels.[20] Meeting this goal requires that the international community significantly reduce its dependence on fossil fuels. Scientists estimate that globally, a third of oil reserves, half of gas reserves and over 80% of current coal reserves must remain unused between now and 2050 in order to meet the 2°C target.[21] However, the world population is projected to increase to 9.9 billion in 2050 from the population of 7.4 billion in 2016.[22] Furthermore, global energy needs are projected to increase even faster due to economic growth in developing nations; the global energy demand was 549 quadrillion Btu in 2012 and is expected to reach 815 quadrillion Btu in 2040.[23] In order to combat climate change and improve living standards globally, the disparity between energy demand and fossil fuel consumption must be met with a rapid growth in zero-carbon energy production.

The abundance of solar energy makes it a clear replacement for fossil fuels. Solar energy is the most abundant energy resource on Earth. At any moment, 173,000 terawatts of solar energy is striking the Earth's surface, which is 10,000 times the world's total energy needs.[24] Furthermore, the solar energy resource is 200 times larger than all other renewable energy resources combined.[25] In addition, the materials needed to produce solar panels are relatively abundant. Silicon is the second most abundant element in Earth's crust and silicon-based solar cells had 93% of the market share in 2015.[26] Thus, solar cells made from common materials could satisfy all our energy needs.

In addition, the price of photovoltaics (PV) is close to reaching grid parity with fossil fuels. The cost of crystalline silicon PV cells has decreased exponentially over time, as shown in Figure 1.1. In 2015, the cost of PV modules for utility-scale systems was only $0.65/W. However, this does not take into account other costs associated with solar development, including balance of system costs (racking, inverter, other electrical hardware) and soft costs like labor and overhead. Still, the total levelized cost of energy for utility-scale solar PV plants entering service in 2022 is projected to be $85/MWh, compared to $123.2/MWh for coal-fired power plants, $57.3/MWh for conventional natural gas-fired power plants, and $82.4/MWh for advanced combined cycle natural gas-fired power plants with carbon capture and sequestration. Including tax credits, the cost for utility-scale solar would be only $66.8/MWh.[27] If the cost of PV continues to decline as expected, it will soon reach grid parity with all fossil fuel sources.

The reasons to invest in solar energy are not just environmental or financial. Solar energy has

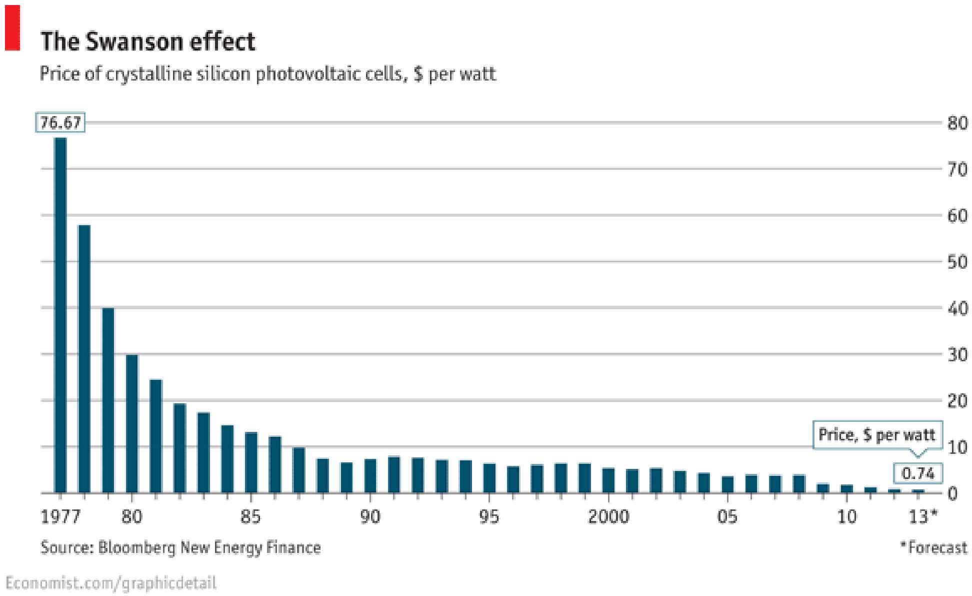


Figure 1.1: The price of crystalline silicon photovoltaic cells has decreased exponentially since 1977.

the potential to bring energy security to nations and energy democracy to communities. Solar energy does not require constant fuel inputs whose prices are influenced by both market forces and geopolitics. It is conducive to distributed generation, which is electricity generation installed by a customer or independent power producer that is connected at the distribution system level of the electric grid.[28] Distributed generation has the potential to increase the reliability and resiliency of the electric grid, improve power quality, reduce peak power requirements, and decrease land use for energy production, although it can also have negative land impacts.[29] Furthermore, it can deployed at many scales, from a 5 kW rooftop installation to a 100 MW solar farm. This enables residents, communities, or small investors to make decisions about their energy sources and create wealth, since a PV array can last 20 years or longer and can provide virtually free energy after installation costs are recovered. However, the transition to clean energy will not be a revolution unless it is accessible to everyone and high capital costs remain a financial barrier to many people. Fortunately, there are financial structures for solar development that can make solar energy affordable and accessible to low-income and middle-class people; some of these financial structures are discussed in Section 1.4.

Photovoltaics are by no means the only way to capture solar energy. Solar thermal energy can be collected in order to heat and cool air and water or even to generate electricity. Solar water heaters can provide hot water for homes and buildings, while concentrated solar power can boil water and power a turbine. These technologies are often more efficient than PV but they are not as easy to mass-produce or scale up and down and have higher capital, operation and maintenance costs. For example, energy from utility-scale solar thermal power plants entering service in 2022 is projected to cost \$184.4/MWh (including tax credits), while utility-scale solar PV is projected to cost \$66.8/MWh.[27] If the goal is to generate electricity from the sun, then a PV array may be the only realistic option.

1.2 How Do Photovoltaics Work?

Photovoltaic cells convert sunlight into electricity. At a fundamental level, power is produced when current flows across a potential difference. Regardless of its composition, a PV cell must do three things to produce power: absorb photons, separate charge carriers, and transport charge carriers to conductors. In order to increase photoabsorption, PV cells often have anti-reflective coatings and cell thickness is increased to increase the probability of absorbing incident photons. Next, those photons must create a charge separation by exciting electrons into higher energy states; this phenomenon, called the photovoltaic effect, is only exhibited in certain kinds of materials. In silicon PV cells, a photon excites an electron from a ground state in the valence band to an excited state in the conduction band, which leaves an absence of negative charge (i.e. a positive charge) called a hole. The band gap is the energy difference between these bands and is an intrinsic property of semiconductors like silicon. Finally, electrons and holes must be transported to a conductor and through a circuit so they can provide useful electrical work before they recombine. Thus, each cell must have two wires: one at high potential where current is going out and one at low potential where current is coming in. This process is demonstrated in Figure 1.2.

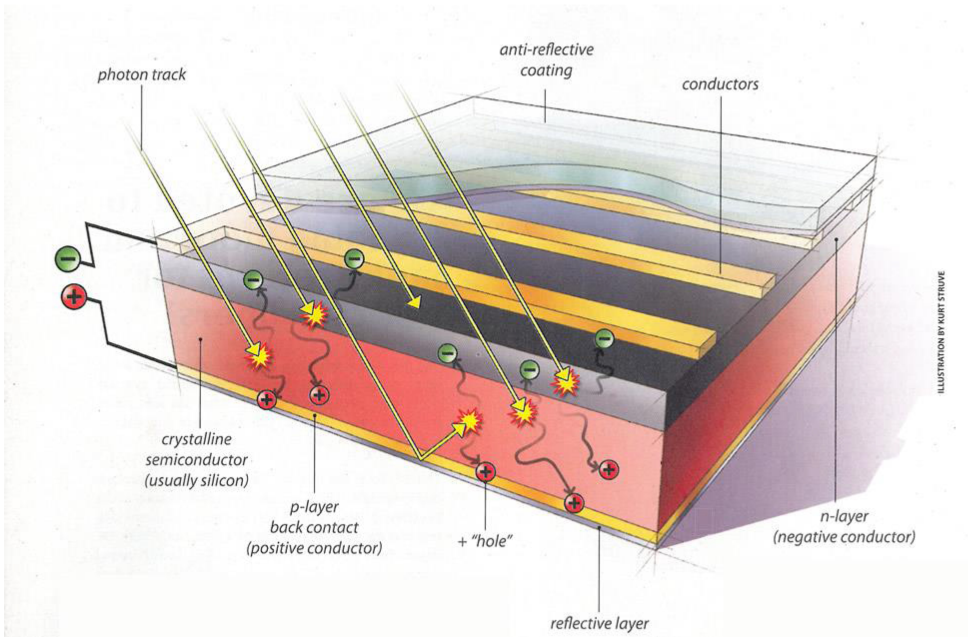


Figure 1.2: Diagram of photovoltaic effect in a crystalline silicon solar cell.[7]

A solar panel, or module, is a network of PV cells connected in series and parallel combinations. Voltage adds when cells are connected in series and current adds when cells are connected in parallel. Although single-junction solar cells can reach efficiencies of over 30% in theory,[30] real modules do not reach maximum theoretical efficiency because of other losses, including reflection

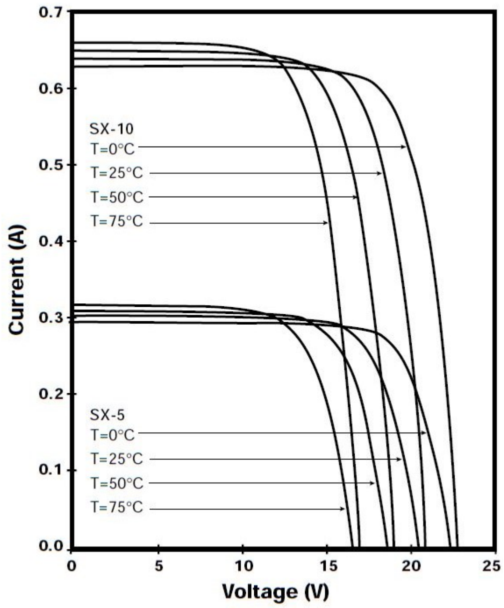


Figure 1.3: Current-voltage characteristics of the BP SX 10 module.[8]

and internal resistance. The efficiency at the maximum power point for commercially available modules can reach up to 22.4% for crystalline silicon, 19.9% for multicrystalline silicon, 18.6% for thin-film cadmium telluride, and 15.7% for thin-film copper indium gallium selenide.[31] Efficiencies are further reduced by shading, soiling, DC to AC conversion, and degradation from thermal and UV exposure over time.

The performance of a solar panel is defined by its current-voltage characteristics. The current and voltage of a solar panel can be empirically measured at varying loads. The power at every point can also be calculated by multiplying current and voltage. The rated power of a solar panel is the power at the maximum power point, P_{mpp}, at standard test conditions (STC), 25°C and 1000 W/m^2.[32] The efficiency is equal to the rated power per unit area divided by 1000 W/m^2. The highest possible current and voltage that a solar panel can achieve are called the short-circuit current, I_{sc}, and open-circuit voltage, V_{oc}, respectively. As the names imply, I_{sc} is the current when $V = 0$ and V_{oc} is the voltage when $I = 0$. The fill factor is the ratio of the rated power to the product of I_{sc} and V_{oc} at STC and is always less than 1. An example of current-voltage characteristics for a PV module is shown in Figure 1.3. As seen in the figure, the current-voltage characteristics are not constant but depend on ambient conditions, including not only temperature but also incident solar radiation.

1.3 Policy

Solar energy policy is part of the broader energy policy of the United States. Solar energy is affected by federal, state and municipal policies. Many policies provide incentives, which can be administered through loans, research and development funding, and tax credits, deductions, and exemptions. However, other important policies are not directly financial, such as interconnection standards. Entire books could be written about solar energy policy, not to mention energy policy as a whole; therefore this section will only introduce the most important policies and government agencies.

1.3.1 Federal Policy

The US has been a fossil fuel-powered nation since the 20th century, relying on coal, oil and natural gas for most of its energy needs. Understandably, US federal energy policy has historically promoted increasing domestic fossil fuel supply. However, since the 1970s, energy policy has become more supportive of alternative energy sources while still heavily supporting fossil fuels. This shift has been primarily influenced by energy crises triggered by events in the Middle East and increasing concern about environmental degradation, including climate change.

The growth of solar has been subsidized by the Public Utilities Regulatory Policies Act (PURPA) of 1978. PURPA was designed to eliminate the monopolization of electricity by utilities and has been effective in promoting renewables by requiring utilities to buy power from independent companies that could produce power for less than what it would have cost for the utility, called the "avoided cost.[33] It established a new class of independent power producers called Qualifying Facilities (QFs) that would receive special rate and regulatory treatment, divided into two categories: small power production facilities and cogeneration facilities.[34]

The Federal Energy Regulatory Commission (FERC) oversees the certification and regulation of Qualifying Facilities. FERC is an independent, self-funding regulatory agency within the Department of Energy whose responsibilities include regulating the transmission and wholesale sales of electricity in interstate commerce. FERC's legal authority comes from the Federal Power Act.[35] FERC sets the standard interconnection agreements and procedures for small generators and also determines the criteria for QFs.

Most federal incentives for the deployment of renewable energy are administered by the Internal Revenue Service. The Internal Revenue Service is part of the Department of the Treasury and is responsible for tax collection and tax law enforcement. Residential Renewable Energy Tax Credits and Business Energy Investment Tax Credits (ITC) were established by the Energy Policy Act of 2005. Credits for PV and solar thermal technologies were expanded and/or extended by the Energy Improvement and Extension Act of 2008, the American Recovery and Reinvestment Act of 2009, and most recently by the Consolidated Appropriations Act of 2015. The ITC was set to expire at the end of 2016, but its extension set the stage for continued growth and expansion of solar energy. Currently, a taxpayer may claim a credit of 30% of qualified expenditures, with a gradual step down between 2019 and 2022.[36] [37] In addition, businesses may recover investments in certain property through depreciation deductions under the Modified Accelerated Cost-Recovery System (MACRS). Most solar technologies qualify as five-year property. The Economic Stimulus Act of 2008 included a 50% first-year bonus depreciation. This bonus depreciation has been extended and modified multiple times; currently, equipment placed in service before January 1, 2018 can qualify for 50% bonus depreciation. Equipment placed in service in 2018 or 2019 can qualify for 40% or 30% bonus depreciation, respectively.[38]

1.3.2 State Policy

Massachusetts ranks third among states in both number of installations and installed capacity for solar PV.[39] In spite of its small size and intermittent sunshine, Massachusetts has emerged as a leader in solar due in large part to its progressive public policies, including tax credits, net metering, renewable portfolio standards, and a state-sponsored loan program.

Energy crises in the 1970s spurred the passage of renewable energy policies at both the state and federal levels. In the late 1970s, Massachusetts created many tax incentives to promote renewable energy. Today, tax incentives continue to promote the growth of solar, including the Renewable Energy Equipment Sales Tax Exemption, Renewable Energy Property Tax Exemption, the Excise Tax Exemption and Excise Tax Deduction for Solar or Wind Powered Systems, and the Residential Renewable Energy Income Tax Credit.

The implementation of PURPA in Massachusetts led to the creation of net metering. After PURPA was passed in 1978, the Massachusetts Department of Public Utilities (DPU) had to decide the avoided cost for electric utilities purchasing electricity generated by Qualifying Facilities. Under PURPA, the utility is required to pay independent power producers at the avoided cost rate, even if the power producer could produce energy at a lower rate. In 1981, the DPU announced that the avoided cost for QFs smaller than 30 kW was the retail electricity rate. This effectively created net metering in Massachusetts.[40] However, net metering facilities (NMFs) ultimately became differentiated from QFs and followed different regulations and rate structures.

Net metering in Massachusetts is regulated by the DPU. NMFs are categorized into three classes based on source and size: Class I includes any facility smaller than 60 kW, Class II includes facilities powered by solar, wind, agricultural projects or anaerobic digestion between 60 kW and 1 MW, and Class III includes facilities powered by solar, wind, agricultural projects or anaerobic digestion between 1 MW and 2 MW. Net metering has existed in Massachusetts since the 1980s, but it was greatly expanded by the Green Communities Act of 2008. The Green Communities Act also increased the value of net metering credits to nearly the retail rate for electricity and allowed net metering customers to allocate net metering credits to other accounts or even other customers. However, the amount of power that can be produced by NMFs is capped and new NMFs must submit an Application for Cap Allocation. The aggregate capacity limits are 8% of a distribution comapny's peak load for municipal or governmental NMFs and 7% for private NMFs. Once a cap for a certain distribution company is reached, no new NMFs can be connected unless the capacity is 25 kW or less.[41] In the Massachusetts Electric territory of National Grid service, the DPU approved net metering caps of 359.17 MW for private customers and 410.48 MW for public customers, effective April 11, 2016.[42] As of May 1, 2017, the aggregate capacity of NMFs under these caps was 206.862 MW among private customers and 254.418 MW among public customers.[43]

Net metering allows utility customers to generate and export electricity in order to offset their own usage. Customers can lower their electricity bills and save money if they can produce power more cheaply than it costs to buy from the utility. Standard meters cannot track electricity exports; a special bi-directional meter, called the “net meter,” must be installed that spins forward when a customer uses electricity and spins backward when a customer exports electricity. A net meter allows a customer to buy electricity from the grid when electricity consumption is greater than electricity generation or sell electricity to the grid when generation exceeds consumption. However, a customer cannot be paid for excess generation; if they produce more electricity than they use during a billing period, then they receive a net metering credit that they can roll over to the next billing period or allocate to other accounts to offset their electricity bill(s). Net metering credits allow a customer to generate electricity behind one meter and allocate the net metering credits to offset loads behind other meters. In order to qualify for net metering, all meters must be served by the same utility and be in the same load zone.[42] As long as the end-use customer does not receive payment for excess generation, whether on-site or off-site, then FERC does not consider this to be a “sale for resale” and it is not necessary to file as a QF under the Federal Power Act.[44]

Net metering credits are calculated in a complex and detailed manner. Net metering credits are calculated by multiplying 100% of the excess kWh by the sum of the basic service charge, distribution charge, transmission charge, and transition charge. (The net metering rate for most Class III NMFs is slightly lower since it does not include the distribution charge.) The value of these charges depends on the customer’s distribution company and the rate class of the host customer and varies over time, but their sum is comparable to the retail rate for electricity.[45] However, on April 11, 2016, Governor Charlie Baker signed a law called Act Relative to Solar Energy, which defined a market net metering credit worth 60% of a regular net metering credit that applied to all solar NMFs larger than 25 kW.[46]

However, in order to receive payment for net *exports* of electricity, a generation facility must file with FERC and obtain QF status. Unlike net metering, a QF sells electricity to the distribution company to serve other customers, rather than offsetting the electricity consumption of a particular customer. Thus a QF does not need to be associated with an on-site (behind-the-meter) or off-site load. However, the compensation received by QFs for excess generation is based on ISO New England wholesale clearing prices and is worth significantly less than net metering credits.[47] In 2016, the average annual price of wholesale electricity in New England in 2016 was about $0.03 per kWh.[48]

In addition, Massachusetts requires that utilities uphold renewable portfolio standards (RPS) passed by the state legislature. RPS are quotas on the amount of renewable energy that must be used by electricity suppliers (both regulated distribution companies and competitive suppliers); suppliers must purchase certificates from clean power producers or pay an alternative compliance payment, which is then used to fund new renewable generation projects throughout the state.[49] RPS for Massachusetts was established by a utility restructuring act in 1997 and were revised by the Green Communities Act in 2008. The Green Communities Act led to the development of three programs: RPS Class I, RPS Class II, and Alternative Energy Portfolio Standards (APS).[50] The

Green Communities Act assigned responsibility for administering RPS and APS to the Department of Energy Resources (DOER), a constituent department of the Executive Office of Energy and Environmental Affairs (EEA).[51] RPS Class II includes facilities that began operation on or before December 31, 1997, while facilities that began operation after that date are classified as Class I. The Green Communities Act created APS in order to incentivize the development of alternative energy systems that are not renewable, such as cogeneration. Beginning in January 2010, DOER carved out a portion of the RPS Class I renewable energy requirement specifically for solar PV facilities. Solar Carve-Out aimed to develop 400 MW of solar PV across Massachusetts.[52] By May 2013, this goal was reached,[53] and a new program, Solar Carve-Out II, went into effect on April 25, 2014 with the goal of 1,600 MW of solar PV by 2020.[54] On February 5, 2016, DOER announced that the cap for projects larger than 25 kW_{DC} under Solar Carve-Out II had been reached.[55]

The electricity produced by RPS Qualified Generation Units is broken into two products: 1) the electricity production that is used on-site or delivered to the grid and 2) the positive environmental attribute associated with avoided greenhouse gas emissions. The electricity itself can be used on-site or sold to the grid via net metering. However, the positive environmental attribute also is given a monetary value; in exchange for a megawatt-hour of electricity, a Generation Unit will receive a Renewable Energy Certificate (REC), which further incentivizes third-party producers to produce clean energy and sell electricity to utilities. The New England Power Pool Generation Information System issues and tracks all RECs.[49] Class I and Class II Generation Units are given Class I RECs and Class II RECs, respectively. In addition, Generation Units under Solar Carve-Out and Solar Carve-Out II receive Solar Renewable Energy Certificates (SREC I/II) that can be sold for a fixed yearly price on the Solar Credit Clearinghouse Auction or sold on the open market.[50] While the prices of RECs and SRECs fluctuate, SRECs have historically been more valuable than Class I or Class II RECs. One way to compare the value of RECs and SRECs is to compare the alternative compliance payments. The alternative compliance payments for 2017 are $67.70 per MWh for RPS Class I, $448.00 per MWh for Class I Solar Carve-Out, and $350.00 per MWh for Class I Solar Carve-Out II.[56] To incentivize suppliers to purchase RECs, the prices for RECs and SRECs tend to be lower than the alternative compliance payments—for example, the auction price for SREC II in 2017 is $285—but higher alternative compliance payments correspond to higher REC and SREC values.[57]

While institutions can purchase RECs and SRECs to lower their carbon footprints, utilities and competitive suppliers purchase RECs and SRECs in order to meet their state-mandated compliance obligations. The compliance obligation represents a minimum percentage of electricity sales coming from renewable energy. For RPS Class I, the percentage escalates by 1% annually. In 2017, the RPS compliance obligations are 12% for Class I, 2.5909% for Class II Renewable, 3.5% for Class II Waste Energy Generation and 4.25% for APS. The compliance obligations for Solar Carve-Out and Solar Carve-Out II are part of, not in addition to, the Class I minimum standard; they also escalate over time, and are 1.6313% and 2.8628% in 2017.[58] Suppliers must file compliance reports annually, and DOER issues an annual RPS and APS compliance report.[59]

Massachusetts also has a lending program designed to promote solar ownership. Locally owned and financed solar projects provide greater financial benefits to residents and the local economy than systems that are leased or owned by third parties. In 2014, DOER announced that it had committed $30 million of RPS alternative compliance payment funds to establish a residential solar lending program. The Mass Solar Loan program launched in the fall of 2015 and is administered by the Massachusetts Clean Energy Center (MassCEC).[60] The Solar Loan program expands access to low-interest financing for Massachusetts residents looking to purchase and install solar PV, including residents with lower incomes or lower credit scores. The Solar Loan program partners with qualifying solar installers and lenders. Solar installers work with residents to guide them through the application process and MassCEC determines their eligibility. Qualified projects must be eligible for Solar Carve-Out II or its successor, have a cost between $3,000 and $60,000 and cannot exceed 125% of the homeowner's annual electricity consumption. Participants of a community-shared solar (CSS) project may also apply to the Solar Loan program, granted that they purchase electricity from the grid and that they receive net metering credits or electricity of 25 kW_{DC} or less. CSS participants do not need to be a homeowner.[61]

While net metering policies and Solar Carve-Out have helped solar expand rapidly in Massachusetts, these policies have also been heavily criticized. The biggest criticism of net metering is that excess generation should not be compensated at the retail rate. Critics argue that this unfairly shifts the costs of transmission and distribution of this energy to other utility customers, especially considering that net metering customers tend to be wealthier and whiter. Advocates counter that net metering has a minimal impact on other residential customers that is far outweighed by the public benefits. Studies have come to different conclusions about the how much "cost-shifting" has been caused by net metering, but the debate reveals deeper problems with the utility model, which relies disproportionately on affluent, high-usage customers and has not adjusted its rate structure to maintain equity in an era of new technologies and policy goals.[62] Solar Carve-Out has been criticized because RECs and SRECs are market-based incentives whose prices fluctuate, causing long-term revenue uncertainty for residential system owners and developers alike. While policymakers believe that Massachusetts' SREC program has been successful overall, the complexity of the SREC market means that sophisticated investors are the best-equipped to make a profit.[63] Finally, the caps for both net metering and Solar Carve-Out have hit and raised multiple times and there is a need for a long-term solution.[64]

1.3.3 New Massachusetts Solar Incentive Program

Massachusetts is now moving away from Solar Carve-Out and SRECs towards a new solar incentive program that will provide long-term revenue certainty. DOER presented the final design of the Solar Massachusetts Renewable Target (SMART) program on January 31, 2017.[1] The main difference between the SMART program and Solar Carve-Out is that the compensation rate will be capacity-based, rather than market-based, and the all-in compensation rate will combine the value of energy and the value of the incentive. In addition, adders will be given based on location, off-taker type, and energy storage capacity and the compensation rate and adders will decline over time to reflect the decreasing costs of solar. Finally, three different compensation options will be available and standalone and behind-the-meter facilities will have their compensation rates calculated differently, ultimately rewarding behind-the-meter, sized-to-load facilities.

Solar Carve-Out was designed to support the solar market until 1,600 MW of capacity was installed statewide, and the SMART program will provide for the next 1,600 MW of solar development. However, the SMART program incentive will decline over time as the cost of solar goes down. The compensation rate will be the same across distribution companies and more solar capacity will be allocated to load zones with higher distribution loads. Most distribution companies, including National Grid, will have eight 200 MW blocks with a 4% decrease in compensation between blocks. Thus, the capacity-based compensation rate factors across all categories and the adder values will decrease by 4% per block.

The SMART program will begin with a competitive procurement process. A request for proposals will be issued for projects greater than 1 MW, and bids must include the capacity-based compensation rate that the project wishes to receive, exclusive of adders. These projects will be divided into two categories, 1 to 2 MW and larger than 2 MW. In each category, projects will be ranked from lowest to highest price and the top 100 MW worth of projects from both categories will be put into Block 1. The highest requested capacity-based compensation rate in each category will become the clearing price for that category. In addition, the clearing price for the 1 to 2 MW category will be used to determine the compensation rate for all other project size categories. DOER will establish two ceiling prices: $0.15 per kWh for 1 to 2 MW projects and $0.14 per kWh for projects larger than 2 MW. However, it is likely that the clearing price will be lower. One developer predicted that the actual clearing price would be between $0.11 and $0.13 per kWh.[65]

After the clearing price of competitive procurement is established, the all-in compensation rate for all facilities will be determined at the time of interconnection based on block, capacity, and eligibility for adders and will remain the same throughout the term. Facilities under 25 kW will have 10-year terms and larger facilities will have 20-year terms. The all-in compensation rate will be equal to the clearing price multiplied by the capacity-based compensation rate factor, plus any adders that the facility is eligible for. The capacity-based compensation rate factor decreases with increasing capacity, as shown in Table 1.1. Additional incentives, or adders, will be given to projects based on location, off-taker type and energy storage capacity, as shown in Table 1.2. These adders can be combined to encourage optimal siting and reward projects that provide unique benefits. In addition, creating a spectrum of project size categories could fill in gaps created by Solar Carve-Out, which created a disparity between facilities under 25 kW that received 100% of the SREC value and megawatt-scale facilities that received only 80% (unless they were solar canopies, community-shared solar, or other favored types) but benefited from economies of scale.[54]

The compensation structure will be differentiated between standalone and behind-the-meter facilities and facilities can be compensated through net metering, on-bill crediting, or fixed payments (standalone only). Standalone facilities will be facilities with no associated load other than

Table 1.1: Project size categories and proposed capacity-based compensation rates (CBCR) under the SMART program [1]

Generation Unit Capacity	CBCR Factor	Example CBCR*
Low income, 0 kW_{AC} to 25 kW_{AC}	230%	$0.3450
0 kW_{AC} to 25 kW_{AC}	200%	$0.3000
25 kW_{AC} to 250 kW_{AC}	150%	$0.2250
250 kW_{AC} to 500 kW_{AC}	125%	$0.1875
500 kW_{AC} to 1000 kW_{AC}	110%	$0.1650
1000 kW_{AC} to 2000 kW_{AC}	100%	$0.1500

*Example CBCR is calculated assuming a clearing price of $0.15/kWh after the initial competitive procurement.

Table 1.2: Adder values under the SMART program [1]

Adder Type	Adder Value ($/kWh)
Building Mounted	$0.02
Brownfield	$0.03
Landfill	$0.04
Solar Canopy	$0.06
Public Entity	$0.02
Low Income Property Owner	$0.03
Community-Shared Solar (CSS)	$0.05
Low Income CSS	$0.06
Solar with Energy Storage	Variable

a parasitic or station load, and all other facilities will be behind-the-meter facilities. Standalone facilities can opt to be paid at a fixed rate equal to the all-in compensation rate, representing the value of both the energy and the incentive. Alternatively, they can net meter or use a similar DPU-approved structure. In this case, the incentive is calculated by subtracting the value of energy from the all-in compensation rate. This effectively results in a fixed compensation rate for both the energy and the incentive. However, if the value of energy exceeds the all-in compensation rate, then the facility would receive no incentive and would be paid only for the value of energy. Finally, behind-the-meter facilities will receive a fixed incentive payment that is determined at the time of interconnection. It will most likely be equal to the all-in compensate rate minus the three-year average of the volumetric charges (the sum of the basic service rate, distribution rate, transmission rate and transition rate) for the host customer's particular rate class. The compensation rate for behind-the-meter facilities will be equal to the value of energy plus the incentive. Even though behind-the-meter facilities will get a fixed incentive, their compensation rate will vary and most likely increase with time as the cost of energy rises. At the completion of this thesis, DOER had not yet clarified how the value of energy will be defined and whether the value will vary between facilities.

The future of net metering is uncertain and an on-bill crediting mechanism has been proposed as an alternative to net metering. The on-bill crediting will be similar to net metering because credits could still be transferred to off-takers. Unlike net metering, though, the rate will be the same for all facilities regardless of size and while there will be no cap on the capacity, there may be a cap on the number of credits that can be transferred to off-takers based on the off-taker's electricity consumption. However, the exact details are unknown and will be established via a DPU-approved regulatory process. It appears, though, that whether a customer chooses net metering or on-bill crediting, excess generation will likely be compensated at a rate lower than the retail electricity rate. This will incentivize behind-the-meter facilities over standalone facilities and encourage behind-the-meter facilities to be sized-to-load. Behind-the-meter systems should therefore be sized so that electricity production does not exceed electricity consumption during any billing period. Since peak production is usually in the summer, it is likely that behind-the-meter systems in the future will offset most of the load in the summer but only a fraction of it in the winter. Standalone systems may still be economically justifiable if economies of scale lower capital costs or adders increase the compensation rate.

For the purpose of this thesis, it was assumed that on-bill crediting would function in a manner similar to net metering and that compensation for excess generation at the end of the billing period would be virtually equivalent. The details of on-bill crediting will be finalized by a DPU approved process, but DOER projects that the compensation rate will likely be set at the basic service rate. The basic service rate is one component of the retail electricity rate, and is usually slightly more than half of the retail electricity rate. Currently, all projects larger than 25 kW_{DC} receive market net metering credits that are worth only 60% of a standard net metering credit, which is valued close to the retail electricity rate. It was assumed that the excess generation would continue to be compensated at a rate equivalent to 60% of the retail electricity rate, whether through net metering or on-bill crediting.

The SMART program will not only eliminate SRECs but will also change how Class I RECs are distributed. Ownership rights to Class I RECs will be automatically transferred to the distribution company and distribution companies will return ownership as long as the facility is eligible to receive payment for the RECs. When the facility's SMART program term ends, ownership rights to the RECs will revert to the owner of the facility. Thus, the system owners will not be able to use Class I RECs to offset carbon emissions when reporting carbon footprint until the end of their 10- or 20-year term.

Finally, the SMART program design is still under review and Solar Carve-Out II has been extended until the SMART program goes into effect. Facilities can resubmit their applications to Solar Carve-Out II and request a good cause extension from DOER. However, this extension is targeted towards projects that have already begun the application process for Solar Carve-Out II and may have faced delays in interconnection, permitting, etc. Any facility under 25 kW_{DC} that is granted an extension will be granted a SREC factor of 0.80. Larger facilities that are granted extensions will be granted different SREC factors based on whether they are authorized to interconnect before March 31, 2018 or the start date of the SMART program.[66] Since the interconnection approval process usually takes longer for larger facilities,[67] small facilities are more likely to be granted extensions, unless a large facility has already begun the application process for Solar Carve-Out II. However, larger projects are generally struggling to compete in the current market because both the net metering credit rate and the SREC factor have been reduced and are not projected to increase in the near future.

1.4 Financing Structures

Innovative financing structures have promoted the rapid expansion of non-residential PV in recent years. Historic barriers to PV adoption have been high up-front costs, inability to utilize tax benefits, responsibility of operation and maintenance, and technology and performance risk. Besides direct ownership, new financing structures such as operating leases, site leases, power purchase agreements (PPAs), net metering agreements (NMAs) and community-shared solar (CSS) have gained in popularity. Since Smith College is a non-profit entity, these financing structures will be discussed with a tax-exempt institution in mind.

Before financing structures can be compared, a new set of vocabulary must be established.[68] The variety of financing structures has led to the diversification of actors involved in solar development. The system owner is the individual or entity that owns the PV system. The site host is the individual or entity that owns or controls the space that the PV system occupies. If the PV system is a net metering facility (NMF), the site host is usually also the host customer whose meter receives net metering services. The host customer is billed for electricity usage or receives net metering credits for excess generation, and can allocate credits to the accounts of other customers served by the same utility company and within the same load zone. Off-takers are customers that receive credits from a NMF but are not the host customer. The developer is the entity that develops, designs and/or installs the PV system. The developer may also hire contractors to design and/or install the system. Cash investors provide initial capital or a constant revenue stream for the project but cannot always make use of the tax benefits, usually due to insufficient tax liability; site hosts and/or developers may serve as cash investors. On the other hand, tax investors are able to efficiently use tax benefits. They are often third-party investors like banks that have considerable tax liability, or tax appetite. Sometimes developers and tax investors partner to form a special purpose entity such as a limited liability corporation (LLC) in order to maximize the value of tax incentives.[69] In financing structures such as leases, PPAs, NMAs and CSS, there are additional roles like lessor, lessee, PPA/NMA provider, and CSS participant that often overlap with existing ones. These will be discussed on a case-by-case basis below.

In a direct ownership model, an individual or entity owns a PV system on their property by either paying up-front or borrowing money from a tax investor (e.g. taking out a loan). The individual is both the system owner and the site host, and is also the host customer if a net meter is installed. The system owner hires a developer to design and install the system. The system owner benefits from avoided electricity costs, net metering credits for excess generation, and government incentives including SRECs or their replacement. However, a tax-exempt organization is unable to benefit from tax benefits like ITC and MACRS so other financing options are usually advantageous. In addition, by owning the system, the system owner is responsible for operating and maintaining the system (or must pay someone else for this service) and assumes the technology and performance risk. Performance risk is the risk that the system produces less electricity than expected or needs unexpected repair or replacement. Thus, there is a small chance of failure to return on investment or debt to creditors. Finally, many system owners are at a further disadvantage if they lack prior experience with procurement, operation and maintenance.

To overcome high up-front costs, a site host may lease a PV system on their property from the system owner. This is known as an operating lease because the system owner acts as the lessor. The system owner hires a developer to design, install and operate the system and receives the tax benefits. Depending on the structure of the lease, either the lessor or the lessee receives the SRECs. The site host is also the host customer; it is entitled to use the generated power and makes recurring payments to the lessor for the length of the lease. These payments must be paid irrespective of system performance and the site host assumes operation and maintenance responsibilities and performance risk. The site host may enter a lease intending to eventually own the system by buying it from the system owner at fair market value at the end of the lease term, in which case the site host is entitled to all the tax benefits. Normally, though, the lease is structured assuming that the site host will *not* purchase the system at the end of the term. The site host's objective is to make lease payments that are less than its electricity bill savings.

Alternatively, the site host can lease their property to a PV system owner. This is a site lease because the site host acts as the lessor.[70] This is usually used for a standalone system that is not serving an on-site load, so a separate meter is installed and the site host is not the host customer. The system owner receives payments from the utility for the generated power, as well as any tax benefits or government incentives, and pays the site host to use their property. In this scenario, the system owner must pay the site host irrespective of system performance and assumes operation and maintenance responsibilities and performance risk. The site host may enter a lease intending to eventually purchase the system from the system owner. The site host's objective is to receive lease payments that are greater than the opportunity cost of using its property for a PV system.

A power purchase agreement lowers the upfront costs of solar and transfers responsibility and risk from the site host to the developer and its tax investors. In a PPA, the developer usually owns the system in partnership with its tax investors (i.e. forms a LLC) or leases it from its tax investors. Since the system owner receives tax benefits and SRECs, it can offer a lower electricity rate than the utility to the site host. The site host agrees to lease their property to the system owner and to buy all of the electricity generated by the system at an agreed-upon price for the length of the PPA. No separate lease payments are made since the site host is also purchasing electricity. If the system produces less electricity than expected, then the site host will have to buy more electricity from the utility but does not owe any money to a third-party investor. Unlike an operating lease, the site host is usually not required to operate and maintain the system. The price usually escalates over time and may end up higher or lower than future utility rates. Sometimes the PPA price increases significantly in order to encourage the site host to purchase the system after the tax benefits have been exhausted.

A net metering agreement is similar to a PPA, except that the off-taker purchases net metering credits instead of power from the system owner.[71] Usually the off-taker is the site host and the host customer and allocates the credits to another account they have with the utility. However, the site host could also be a separate entity that receives property lease payments from the system owner and allocates the credits to the off-taker's account. A NMA is usually used for a standalone system and the power produced is sent directly to the grid, instead of being used for a load on-site. The off-taker pays the system owner for the net metering credits and realizes a monetary credit on their electric bill. This kind of system can be thought of as an "off-site" system because the credits used to lower a customer's electric bill come from power produced at a different location. Usually a NMA is structured as a fixed discount from the utility rate over a fixed period of time in which the off-taker receives 100% of the value of net metering credits and pays the system owner a fixed percentage of that value, such as 95% for a guaranteed savings of 5%. Sometimes, though, NMAs include a floor price for utility rates, below which the off-taker is not guaranteed savings.

Community-shared solar is when individuals cooperatively own or receive power or financial benefits from a PV system.[72] Unlike a conventional direct-ownership model, participants in direct-ownership CSS can own solar panels without being a site host and without owning any property. The CSS participants are also off-takers and use net metering credits to lower their electric bills. CSS participants still need to hire a developer and may need to borrow money from a tax investor. (In Massachusetts, CSS participants still qualify for the Mass Solar Loan program.[61]) If they combine their purchasing power, though, they can get a better price than if each participant was negotiating alone. However, participants in direct-ownership CSS still assume performance risk and responsibility of operation and maintenance. CSS participants may pay the developer or hire a contractor to oversee operation and maintenance.

However, participants in direct-ownership CSS still face high up-front costs. In subscription-based CSS, a site host leases a site to a special purpose entity that develops a CSS array and receives regular subscription payments from CSS participants, who can also be called subscribers. The special purpose entity is usually a LLC created by the developer that can utilize tax benefits and SREC sales to lower the cost for participants. Unlike direct-ownership CSS, participants do not need to have tax liability and do not need to have the capital or credit-worthiness to pay upfront or qualify for a loan, making it more accessible for low-income people.[73] (However, some credit approval may still be necessary to qualify, depending on the terms of the subscription.) The electricity produced by the PV system is sold to the site host or sold to the utility through net metering. The CSS participants receive payments or net metering credits from electricity sales that effectively offset their electricity bills. Thus the CSS participants act as cash investors and do not need to have tax liability. The site host can lower the costs for CSS participants by providing initial capital at a lower rate of return than a tax investor and/or leasing the site as a low cost.

1.5 Examples from Peer Institutions

Looking to the examples of peers can guide Smith College and other institutions through the solar development process. Since most colleges and universities are non-profit institutions, most campuses have taken used financial structures that involve third-party ownership. Power purchase agreements have been the most popular; over 100 MW of solar capacity at 61 universities was financed through PPAs before 2015, representing 68% of total capacity across U.S. universities. The average system size with a PPA, 700 kW, is also larger than the average system size without a PPA, 100 kW.[74]

For this thesis, inspiration was taken from several colleges and universities that had recently undertaken solar development projects, including Smith's neighbors and fellow members of the Five College consortium. In general, these projects fell into three broad categories: behind-the-meter PPAs, virtual PPAs and NMAs, and community solar programs.

Hampshire College and the University of Massachusetts Amherst were examined as case studies for behind-the-meter PPAs. Both institutions are members of the Five College consortium with Smith College and are served by the same utility company. Both Hampshire College and UMass Amherst are examples of successful megawatt-scale, behind-the-meter PPAs that will lead to long-term savings. In addition, neither of these projects could have been possible without stakeholder engagement or collaboration with third-party companies.

Hampshire College is an innovative private liberal arts college with 1,400 undergraduates located in Amherst, MA.[75] In 2016, Hampshire College installed two PV arrays on their campus with a total capacity 4.7 MW_{DC} and a 500-kWh Tesla battery-storage system.[76] The system is also net metered so Hampshire can buy electricity from the utility or receive credits for excess generation. To make this decision, Hampshire's Environmental Committee led a two-year sustainability planning process that included a review of current and future land use. In this process, Hampshire was driven by their president's commitment to be carbon neutral by 2032 and their community's value on social and environmental responsibility, including the responsibility to produce local clean energy and responsible land stewardship. They realized that with the open spaces on their campus, they could produce 100% of campus electricity from on-site renewable energy.[77] Ultimately, the committee recommended installing ground-mounted arrays on two different fields, one behind forests and one next to a main road.[78] Hampshire issued a request for proposals and chose to enter a PPA with SolarCity, which will use the ITC and SREC sales to sell electricity to Hampshire below the retail rate and lead to savings of $300,000 to $400,000 per year. Since the PV arrays are installed on arable land, Hampshire and SolarCity are working together to preserve soils and maintain ecosystems, demonstrating that renewable energy can coexist with agricultural land use.[77]

The University of Massachusetts Amherst is a public research university with 21,800 undergraduates and is the flagship of the UMass system.[75] Similar to Hampshire College, UMass Amherst has installed a large amount of solar on-campus. Brightergy designed and constructed eight PV arrays totaling 5.5 MW_{DC}, including two above parking lots with a combined capacity of 4.5

MW_{DC}.[79] Sol Systems arranged the project financing, and the system will be owned by ConEdison solutions, which will pay Brightergy to maintain and operate the system and sell electricity to UMass Amherst for 20 years. The $16 million project will generate 5,900 MWh annually, roughly 4% of the campus load, and will save the university $3.6 million (in net present worth) over the next 20 years.[80] This process began when their Sustainability Manager developed a solar energy plan in 2013 in order to meet future state renewable energy procurement goals. UMass Amherst decided not to use open land for solar development and pursued a PPA in order to lower the upfront costs. A stakeholder committee of faculty, staff and students narrowed down rooftop and parking lots options based on physical constraints and issued a request for proposals. Competitive Energy Services provided financial analysis of the bids, and ultimately, UMass Amherst chose a PPA for six roof-mounted arrays at $0.03 per kWh and two solar canopies at $0.075 per kWh, which is still half their current utility rate. The systems are completely behind-the-meter and involve no net metering, which is feasible because the university has its own electrical substation. University staff worked closely with Brightergy during the design and construction process, and also negotiated with ConEdison to provide high-resolution data and interactive energy dashboards to enhance the educational benefits.[81]

While both Hampshire College and UMass Amherst installed on-site PV arrays, many institutions have developed solar off-site in order to offset a larger portion of their carbon footprint or on-campus electricity demand. Notable examples are Stanford University, American University and George Washington University. Stanford teamed up with SunPower to design and build the 67 MW Stanford Solar Generation Station in a western valley of the Mojave Desert. The panels have single-axis tracking and dampeners to avoid damage from high winds. The solar plant combined with campus rooftop installations will produce 53% of Stanford's electricity.[82] Stanford will purchase all the energy generated at a fixed price, as well as the renewable energy certificates, for the next 25 years through a PPA. New Energy Solar has also acquired a majority interest in the project.[83] American University and George Washington University have entered a joint off-site PPA called the Capital Partners Solar Project. Duke Energy Renewables built a 52 MW_{AC} PV array across three sites in northeast North Carolina and will maintain and operate the array and sell the electricity at a fixed price, as well as renewable energy certificates, to the partners. The array is expected to produce about 117,000 MWh per year and will cover half the electricity needs of American University and George Washington University and about 30% of the needs of George Washington University Hospital. The system will be owned by Dominion Resources. The array and all partners are connected to the regional grid operated by PJM Interconnection. Stakeholders from all three institutions were involved in the development process and were advised by CustomerFirst Renewables. They issued a request for proposals for 20-year contracts for large-scale renewable energy projects (including both solar and wind) and ultimately chose Duke Energy Renewables based on the total delivered cost and its experience and reputation.[84]

Several colleges and universities are also exploring community solar programs. Many different kinds of programs have been called "community solar;" for the purpose of this thesis, community-shared solar (CSS) has a specific definition, but other kinds of programs, such as group purchasing, can also provide benefits to a community. In 2016, the University of Minnesota purchased two megawatts of subscriptions from a community solar garden in Dakota County which is an example of a subscription-based CSS. With their subscription, the university is getting credits on their electric bill and renewable energy certificates and anticipates savings of $800,000 over the 25-year contract. The community solar garden is operated by Geronimo Energy but the subscriptions are administered by Xcel Energy.[85] The University of Utah was the first university to sponsor a community solar program. The program, which was called U Community Solar, helped University of Utah community members learn about installing solar panels on their homes and facilitated a group purchasing program that lowered the cost of panels and installation; while this does not qualify as CSS, it did provide significant benefits to their community. Utah Clean Energy administered the program, which lasted for six months and resulted in 380 homeowners committing to purchasing solar, totaling 1.8 MW. In addition, nearly 1,700 individuals expressed interest in installing solar panels by taking an online survey and 750 people attended 11 educational workshops. The program also boosted the local economy, generating $1 million in wages and $6 million in revenue for solar installation companies.[86] Another example of a community solar project is Serenity Soular, an initiative to bring affordable solar energy and green jobs to North Philadelphia. Serenity Soular is a project of Serenity Soular, a coalition in North Philadelphia that began as a collaboration between Swarthmore College and Serenity House, a community outreach center in a neighborhood with high rates of unemployment and poverty. At first, community residents were interested in a roof garden on the garage, but when it was discovered that the garage could not hold the weight, an engineering professor led a series of workshops on solar power for community residents that culminated in the installation of a solar panel on the garage to power lights in the backyard. Sustainable Serenity was chosen as a Solar Ambassador team by RE-volv and raised thousands of dollars through crowdfunding.[87] They partnered with Solar States to install a 5.6 kW solar array on Serenity House, which was completed on July 30, 2016, and will be working next to solarize Morris Chapel Baptist Church. Leading up to the Serenity House installation, two young people from the neighborhood were trained and hired as solar installers. The ultimate goal is for neighborhood residents to launch a worker-owned solar installation company.[88] While these programs are all very different, they demonstrate that community solar programs can provide many benefits to communities.

1.6 Contributions

This thesis created a decision-making framework for photovoltaic solar development that focused on the interplay between technical design, stakeholder needs, and constraints. This framework is illustrated in Figure 1.4. The design process was broken into two phases: preliminary design that would inform site selection and detailed design including wiring diagram, wire sizing and life-cycle cost assessment. However, it was recognized that after site selection, most institutions would issue

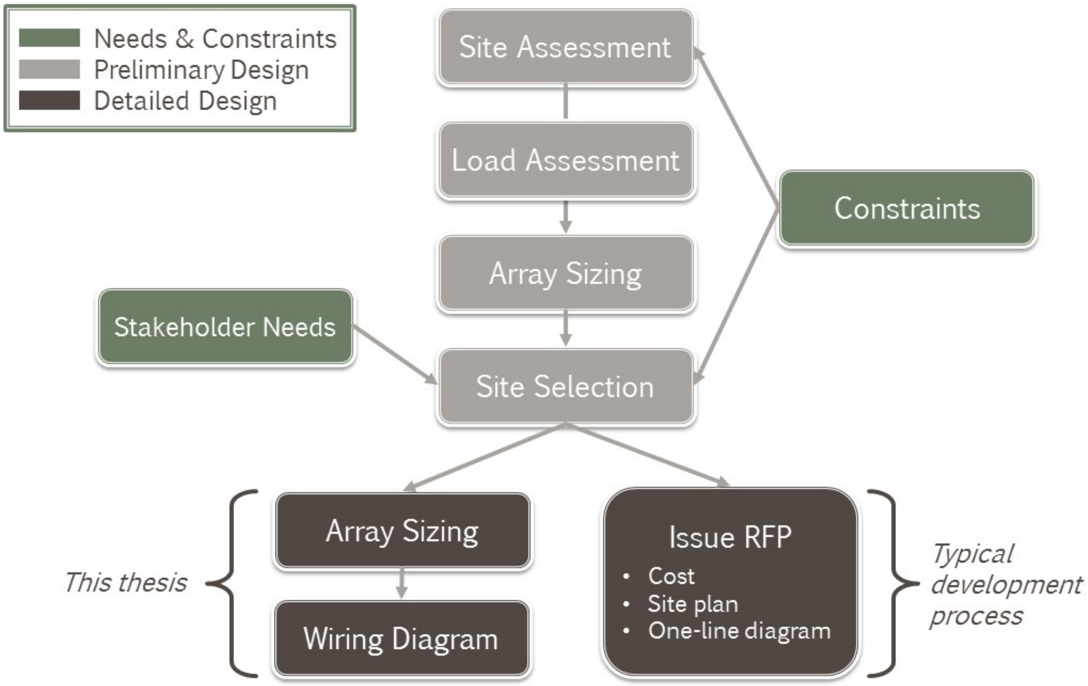


Figure 1.4: Decision-making framework used in this thesis.

a request for proposals and get bids from developers that would include estimated cost, site plan, and one-line diagram, a simplified representation of the electrical circuit.

The design process itself was one used by many developers; however, this thesis is unique because it incorporated stakeholder needs and regulatory, financial and operational constraints into the design process, especially programmatic design and site selection. Needs and constraints were translated into design requirements, and qualitative and quantitative methods were used to compare how design options satisfied these requirements. Finally, broad trends in what kinds of arrays best met the design requirements were identified to help inform future decision-making.

Chapter 2

Problem Framing

This chapter explores constraints and stakeholder interests specific to Smith College and its community as a case study for solar development. Some social and environmental reasons that Smith College should invest in solar development were discussed at the beginning of Chapter 1, including combating climate change and increasing access to the benefits of solar energy. Building more PV arrays on Smith College property would also create opportunities for teaching and research and could help Smith or its community members save money on their electric bills. However, there are risks associated with solar development and constraints imposed by physical limitations, government regulations and Smith's energy infrastructure. Needs and constraints were translated into design criteria that were later applied to potential sites for PV arrays to determine which sites would be recommended for solar development.

2.1 Constraints

The first constraints were the physical limitations of the sites. These constraints included roof material, roof age, azimuthal orientation, shading, preexisting nonstructural components, and square footprint. Slate roofs were not considered for solar development because slate shingles are brittle and could be cracked during the installation of PV modules, leading to leaks and roof damage.[89] Roofs older than 20 years were also not considered. PV arrays often last 20 years or longer, and if an old roof needed repair or replacement before the payback period of the array was over, then the stakeholder would not benefit from the array's full value. Buildings that only had available roof area on the north side (surface azimuth angle less than -90° or greater than +90°) were eliminated since a south-facing roof is ideal at northern latitudes. Sites that were mostly shaded were also eliminated. Shading more than 25% of a single cell can decrease the power output of the entire string significantly; shading more than 40% of one cell can even lead to zero power output.[90] In addition, some roofs have nonstructural components such as fans, hatches, and drains that are important for building function and cannot be removed. Thus, buildings whose roofs were mostly covered with nonstructural components were not considered. Finally, buildings with a square footprint under 5000 ft^2 were not considered. PV modules can only be mounted on a fraction of a building's footprint because at least half of a pitched roof is usually shaded (assuming a south-facing orientation), modules may not fit in irregularly shaped corners, and clearances should be left for fire safety. Massachusetts Executive Office of Energy and Environmental Affairs recommended a 3-ft clear access pathway for pitched roofs and a clear perimeter at least 3-ft wide for all roofs.[91] For buildings with a footprint under 5000 ft^2, the available space left is usually not enough to generate more than a few kilowatts of power. Given economies of scale, this would not be an efficient use of money or space when other options are available. While this is related to maximizing the benefits for stakeholders, square footprint was treated as a constraint because it was applied during site assessment.

Smith's current energy infrastructure was also an important constraint. The majority of Smith campus gets electricity from a microgrid that is separate from the local grid powered by Massachusetts Electric, an electric distribution company owned by National Grid. In other words, most of campus is behind the same meter, which is called the "main meter." For the purpose of this thesis, sites connected to the main meter were considered "on-campus" and sites not connected to the main meter were considered "off-campus."

Smith's cogeneration plant is located behind the main meter and provides most of the electricity and heat used by Smith College. At the cogeneration plant, a natural gas-fueled turbine produces electricity and waste heat from the turbine is used to generate steam for heating buildings. The cogeneration plant began operating in 2008 and is expected to remain in operation for at least 15 more years.[92] The turbine operates between 1.8 and 3.6 MW and produces reliable electricity for the campus, even when the local utility has a power failure.[93] If the cogeneration plant cannot meet the campus demand, additional electricity is purchased from the local utility or from PV arrays on the Campus Center, Indoor Track and Tennis Facility, and Ford Hall. While the total rated capacity of these arrays is about 500 kW, their actual power production varies from 0 to 200 kW, depending on the weather. The high degree of variability can cause problems at the cogeneration plant, especially on a day with intermittent sunshine.[93] Since 25 kW is a tipping point for SMART program incentives (see Table 1.1 in Section 1.3.3) and the next tipping point is higher than the peak production of existing arrays, it was predicted that any system larger than 25 kW would cause more problems at the cogeneration plant than would be justified by the marginal benefits. It is possible that adding energy storage (e.g. batteries) on-campus would help to smooth demand, but since this does not yet exist, analyzing scenarios with energy storage was considered outside the scope of this thesis. Therefore on-campus arrays installed behind the main meter were constrained to 25 kW, while off-campus designs were not constrained by the cogeneration plant.

The interface of Smith College and the local utility introduced additional operational constraints and financial impacts. Any grid-connected system must be approved to interconnect by the local utility before it can begin operation. In addition, a copy of the authorization to interconnect must be submitted before the end of a SMART program block period in order to receive that block's compensation rate.[1] This process can be very long and expensive, especially for large systems. The interconnecting customer is also responsible for paying the application fee, witness test fee, and the costs for any impact studies, grid modification requirements, and behind-the-meter interconnection equipment.[94] However, this process might be easier if Smith installed PV arrays behind-the-meter. The University of Massachusetts Amherst, which is served by the same utility as Smith, also has a cogeneration plant and successfully amended their existing interconnection service agreement (ISA) when they added PV arrays behind-the-meter.[81] This allowed them to expedite the interconnection process.

In addition, the cost of purchasing electricity from National Grid provided a reference for deciding whether a PV system would be economically justified. The retail electricity rate in the present and near future was assumed to be $0.13 per kWh for Smith College.[95] This is an average value, since Smith College pays slightly lower rate at its main meter and a slightly higher rather at its smaller meters. The retail rate includes the costs of supply services (electricity purchasing from wholesale suppliers and distributed generation) and delivery services (distribution charges, transmission charges, etc.).

The emissions associated with electricity purchased from the utility provided a reference for evaluating the environmental impact of a PV system. In 2015, 64% of Massachusetts electricity came from natural gas, while 7% came from coal.[96] Since the combustion of fossil fuels produces greenhouse gas emissions, replacing electricity purchased from the utility with electricity purchased from carbon-neutral energy sources like solar would have a positive environmental impact. If Smith owned the RECs associated with renewable energy generation, Smith could reduce its carbon footprint by 0.292 metric tons of CO_2 equivalent per kWh when the Office of Campus Sustainability reported emissions.[97]

Smith's status as a non-profit institution would limit its ability to use government incentives for solar energy and its ability to receive payments for solar energy. Since Smith is tax-exempt, it is not allowed to use tax credits, exemptions, and deductions under federal and state regulation. Therefore Smith must work with a third-party system owner in order to access these incentives. For instance, in a PPA, a developers can form a partnership with an investor and together they own and operate the system. Then the developer can monetize the federal ITC and accelerated depreciation and sell the power to a non-profit entity at a discounted rate.[68] In addition, non-profit institutions are only allowed to have a small percentage of unrelated business income or they risk taxation.[98] Therefore, Smith can only benefit financially from a PV array by lowering its electricity bill. Smith can offset its consumption of grid electricity directly by producing electricity on-campus or indirectly by producing electricity off-campus and receiving credits. Thus, financing options like an operational lease or a site lease may not be available to Smith College.

State regulation of RECs also restricts who can claim to be using renewable energy. Continuing with the PPA example, the third-party system owner also owns the environmental attributes associated with electricity generated from renewable energy. The system owner can sell the RECs on the market and lower the cost of electricity for the power purchaser or the power purchaser can buy the RECs from the system owner. Although this increases costs to the power purchaser, the power purchaser gets to claim the environmental attributes. Only the individual or entity that owns RECs can claim to be using renewable energy and lowering its carbon footprint.[99] Smith College reports its greenhouse gas emissions and owning RECs could help Smith achieve its goal of carbon neutrality by 2030.[100] However, under the SMART program, SRECs will be eliminated and ownership rights to Class I RECs will automatically transfer to the distribution company and be counted towards meeting the state's renewable portfolio standards.[1] Even if Smith doesn't own the RECs, installing PV on its property is still good for the environment because it supports the growth of the solar industry and increases the amount of renewable energy in Massachusetts.

2.2 Stakeholder Interests

Different stakeholders at Smith College have different interests in solar PV. For PV development, important stakeholders to consider are Campus Sustainability, Facilities Management, College Relations, Finance and Administration, and of course students and faculty. In addition, any Smith community member that is in the same load zone as Smith College could receive direct financial benefits from participating in a community-shared solar array.

The Office of Campus Sustainability integrates environmentally sustainable practices at Smith College, including operational initiatives like promoting renewable energy. Installing renewable energy systems on Smith property or purchasing energy from renewable sources doesn't decrease Smith's carbon footprint unless Smith owns the associated RECs. If Smith does own the RECs, then this could help Smith towards its goal of carbon neutrality. Even if Smith doesn't own the RECs, though, Smith can still be a leader on climate change among higher education institutions by increasing renewable energy in the grid and supporting innovative, equitable models of renewable energy development.

Facilities Management is responsible for maintaining, repairing and altering Smith's buildings. In addition, it operates the cogeneration plant, ensures that electrical supply meets demand, and maintains all electrical infrastructure. Any project that involves changes to the infrastructure of Smith College will require the cooperation and approval of Facilities Management. In particular, as explained in Section 2.1, additional solar capacity added behind-the-meter was limited to 25 kW to avoid interfering with the operation of the cogeneration plant. Furthermore, PV development could lead to changes in land use, building infrastructure (e.g. roofs), and electrical infrastructure. Finally, Facilities Management has an annual budget of $20 million for capital projects, so any capital costs incurred by Smith College must fit within this budget.[101]

The Office of College Relations communicates the mission, values, image and news of Smith College with the college's various constituents. In a world increasingly affected by and concerned about climate change, what Smith is doing to promote a just and sustainable future is important to the Smith community, to Smith's peers, and to society as a whole since Smith is a prestigious liberal arts college. Prospective students and alumnae are two particularly important audiences. New solar arrays at Smith might be mentioned in campus news. Size and visibility matter, but so does the ability to tell a good story, whether it's reducing the carbon footprint or empowering employees to be part of the renewable energy revolution.

The Office of Finance and Administration is responsible for the financial operation of the college, including financial planning and accounting. All capital expenses and operating expenses affect Smith's finances, but long-term investments and contracts have a greater impact. If the college enters a PPA, it is desirable to procure electricity at a rate below the retail rate from the utility. In FY 16, the college purchased about 8,000 MWh of electricity from the utility, about 33% of total electricity consumption, and paid $0.13 per kWh.[95] Ideally, purchasing electricity or credits from on- or off-campus PV arrays would lead to long-term savings. However, savings cannot be predicted without some degree of uncertainty because the retail rates for electricity are subject to changes in fuel costs. Nevertheless, a long-term agreement like a PPA can provide stability by reducing variation in electricity bills. In addition, if the college provides capital for a project, then it should provide a favorable return on investment.

The development, installation, and operation of PV arrays should provide teaching and research opportunities for students and faculty. Location and visibility matter because on-campus arrays that could be seen from the ground would engage more people and make class visits more accessible. In addition, the array should be integrated with data monitoring. High-resolution time-series data of weather, power and energy could be analyzed by students for classes, research and internships and would help Campus Sustainability and Facilities Management keep track of operation. This data could also be added to Smith's interactive energy dashboard and displayed in public spaces.

Finally, community-shared solar represents an opportunity for individuals in the Smith community, especially Smith employees, to access the benefits of solar directly. Smith College already has PV arrays on its campus, but Smith employees may face barriers to "going solar" themselves, including lack of knowledge, financial resources, and/or property suitable for PV. Smith College could lower these barriers by educating employees about the benefits of solar and the solar development process, providing initial capital for a CSS array, and allowing employees to install their solar panels on Smith's property. Employees would receive financial benefits such as net metering credits that would lower their electric bills. The CSS program could also be structured in a way that would be accessible to employees of varying income levels. In return, Smith College would get great publicity and make a bold statement about its commitment to promoting sustainability and equity. CSS could also strengthen the relationship between Smith and its employees and inspire employees to follow more sustainable practices at work and at home.

2.3 Design Criteria

The needs and constraints of Smith College and its community members were translated into design criteria that was later used to decide which array design would be best for Smith College. These design criteria are listed and explained below.

- Feasibility
- Financial impact

- Operational impact
- Environmental impact
- Social and educational impact

Feasibility is an objective engineering analysis of what is physically possible within regulatory, safety, and financial constraints. Feasibility includes mechanical and electric loads, maximum current and voltage, and physical conditions like on-site solar radiation. Feasibility also concerns project complexity and the risk of complications that could lead to delays, unexpected costs, and/or failure.

Financial impact includes the financial impact on Smith College and the financial impact on Smith community members. The financial impact on the college will heavily influence any decision to pursue solar development on its property, but financial impacts on community members, particularly when considering CSS systems, is also important. Solar PV development is an opportunity to make money or save money; thus, how much money and how it is distributed are both important criteria.

Operational impact includes changes to land use, changes to employee responsibilities or new positions, and impact on Smith's building and energy infrastructure, including the cogeneration plant. An ideal PV array would be compatible with future plans, add no work for Facilities Management, and not disrupt existing infrastructure.

Environmental impact includes reducing greenhouse gas emissions of Smith College and increasing renewable energy in Massachusetts, which effectively reduces greenhouse gas emissions in the Commonwealth by replacing fossil fuels. Even though PV arrays generate electricity without emitting greenhouse gases, a PV array requires both material and energy inputs that have environmental impacts. In addition, the environmental impact of a PV array depends where it is located. Installing a PV array on open space, especially green space, could cause environmental degradation, while installing a PV array on a brownfield, a roof, or a parking lot is a more environmentally responsible (and socially responsible) choice.

Social and educational impact includes creating opportunities for teaching and research, helping Smith community members participate in the renewable energy revolution, and inspiring Smith community members and others to adopt sustainable practices and take action on climate change. It is important that the benefits of solar energy are communicated to and understood by the Smith community. In addition, visual impact cannot be understated; on the most basic level, bigger is better and creates a "wow" factor that will engage more people at Smith. In addition, more people will be engaged if the array is visible from the ground in a convenient, on-campus location. Finally, pioneering innovative technologies or innovative financing structures will help Smith stand out among its peers and make a bigger impact.

Chapter 3

Preliminary Design and Site Selection Process

The process of selecting a site for solar development was to identify potential sites, assess load, choose components, determine maximum array size and solar availability on those sites, choose a financing structure for each array, and analyze which array would best satisfy the needs of the stakeholders. The same components were used for all designs in order to make an even comparison. This decision-making framework was applied to Smith College as a case study, with a focus on the interplay between technical design and regulatory, operational and financial constraints.

3.1 Potential Sites

Smith College has 102 buildings behind its main meter ("on-campus) and 17 individually metered sites ("off-campus").[102] [103] These off-campus sites include parking lots and open spaces where solar canopies and ground-mounted arrays could be placed.

The buildings eligible for roof-mounted arrays were narrowed down based on roof material, roof age, azimuthal orientation, shading, square footprint, and preexisting nonstructural components; these constraints are explained in detail in Section 2.1. At the time of this thesis, a consultant was assessing solar development potential on Smith College's rental properties so those buildings were also excluded from this analysis.[100] Assumptions about roof material and square footprint were based on Facilities Management records.[104] This data also provided estimates of roof age, but senior staff at Smith College identified which buildings had roofs more than 20 years and old and which buildings had HVAC equipment or other nonstructural components.[105] Azimuthal orientation and shading were assessed through site visits and aerial imagery. Using process of elimination, options for roof-mounted PV were narrowed down to Ainsworth Gymnasium, Conway House, Cutter House, Wright Hall, and Ziskind House. Senior staff also recommended examining specific non-building options, including the parking lots next to the tennis courts and along Tennis Court Drive, the parking garage on West Street, and the large lot on Fort Hill next to the Center for Early Childhood Education.[105]

3.2 Load Assessment

Before sizing the arrays for the potential sites, it was necessary to determine whether the arrays would be area-constrained or load-limited. Arrays are sized based on "supply and demand," where supply is the available solar energy and demand is the load. Designs for electricity consumers that have a large load and limited area for PV arrays are area-constrained while those with a small load and excess area are load-limited.

On-campus PV arrays would be area-constrained. Even though Smith College gets most of its electricity from the cogeneration plant, Smith still purchased 8,000 MWh of electricity from the local utility in FY 16.[95] Thus, Smith has a high demand for electricity and would therefore need a very large array, about 7 MW, in order to replace all utility purchases with solar energy. (See Appendix D.8.) In summary, Smith is essentially area-constrained if limited to installations behind the main meter.

An off-campus array could be area-constrained or load-limited. If the load at an off-campus site is comparable to the available solar energy, then a PV array would be installed behind the existing meter and the electricity produced would directly power the on-site load. Thus, a behind-the-meter array at an off-campus site would be load-limited. Since off-campus sites are not connected to the main meter, this would not interfere with the cogeneration plant. However, if the available energy is much greater than the load, then it may be more favorable to install a standalone system with its own meter. In this case, the credits could be used to offset the load behind the main meter and the design would be area-constrained. Thus, off-campus arrays are load-limited if the array is behind one of the smaller meters or area-constrained if the array is standalone.

However, as explained later in Section 3.3.2, the available energy at off-campus sites was much greater than the load. The tennis court parking lots and the parking garage were the only off-campus sites that had associated loads. The tennis court parking lots are close to the field house and the athletic fields, whose loads (including the athletic field lights) are served by the same meter. The total electricity consumption for the field house and athletic field lights from February 2016 to January 2017 was 12,877 kWh, or about 13 MWh. (See Appendix B.2.) The parking garage has its own meter and its loads include lights and an elevator. The total electricity consumption at the parking garage from June 2015 to May 2016 was 55,727 kWh, or about 56 MWh. (See Appendix B.1.) However, the available energy was much greater than the load at either site. (See Table 3.2 or 3.4.) Thus, the best option would be to install standalone systems with their own meters and the designs would be area-constrained.

3.3 Area-Constrained Array Sizing

Since the arrays were area-constrained, they were sized in order to maximize energy production. Array sizing includes calculating the number of modules in the array, its power capacity, and how much energy could be produced. The number of modules for each site was estimated by mapping the site and designing a PV system layout using GIS-integrated software. Power capacity and energy production were estimated by modeling with software and by computing annual solar insolation on a tilted surface using a transposition model.

3.3.1 Estimating Number of Modules

The number of modules was optimized to maximize energy production. In most cases, this meant maximizing the number of modules. The maximum number of modules was estimated by mapping the site in Helioscope, which calculated the number of modules that would fit in the defined area. Helioscope is an online software tool that integrates PV system layout and performance modeling. Google Maps is embedded into the user interface and the software comes with a database of PV modules and inverters. For each site, the total surface area of the modules was less than the total area of the site due to shading, irregular site geometry, and/or safety clearances.

First, each site was mapped using Helioscope. After inputting the location, the site was outlined in Google Maps. This meant outlining the roof for buildings and the parking garage, outlining parking spaces on the tennis court parking lots, and outlining the perimeter of the lot on Fort Hill. Keepouts, which are areas where PV modules cannot be placed (e.g. vents, small gables), were also outlined on the map. Keepouts could be given heights and were used to model trees and other shadow-casting objects.

Next, a module was selected from Helioscope's database. Hanwha Q Cells Q.PRO L 310 were used for this design. The Q.PRO L 310 is a polycrystalline silicon module whose physical dimensions are provided in Table 3.1. For all module specifications, see Appendix C.1.

Table 3.1: Physical dimensions of the Q.PRO L 310 module [2]

Length (mm)	Width (mm)	Thickness (mm)	Surface Area (m^2)
1956	988	45	1.93

Then the type of racking, surface azimuth angle, tilt angle, module orientation (portrait/landscape), and setbacks were specified. The options for racking in Helioscope were flush-mount racking, fixed-tilt racking, carports, and east-west racking. East-west racking is used for single-axis tracking. Single-axis tracking increases electricity generation but also increases the installed cost by a roughly proportional amount.[106] However, the increase in electricity production is greater in sunnier regions and any net savings from single-axis tracking in New England may be lost due to weather-related issues.[107] For this thesis, it was assumed that the increased energy production would not justify the marginal costs. PV arrays on pitched roofs were mounted with flush-mount racking. Fixed-tilt racking was used for PV arrays on horizontal surfaces, such as flat roofs or the ground. Solar carports were used for single-row canopies. The surface azimuth angle of the array was adjusted so that the sides of the modules were parallel to the edges of the roof, where possible, in order to maximize the number of modules. An azimuth of 0° (due south) was considered ideal, but any azimuth greater than -90° (due east) and less than +90° (due west) was permitted. The tilt angle was set equal to the roof pitch for roof-mounted systems. The roof pitch was estimated by measuring the slope of the roof from photographs and rounding to the nearest

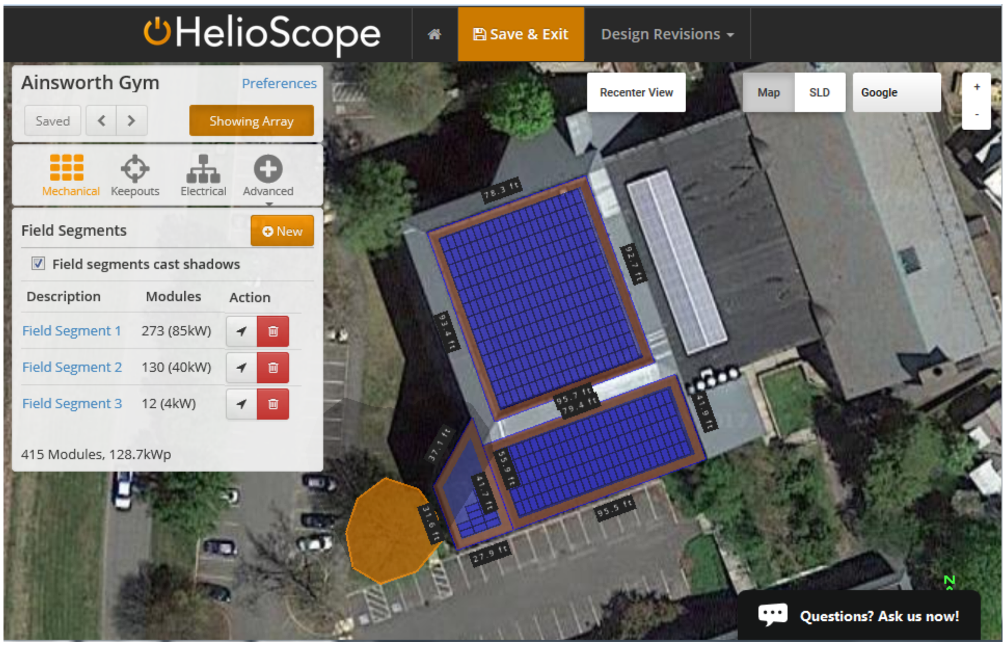


Figure 3.1: Example of Helioscope interface during PV system layout design.

5°. Inter-row shading is not an issue for roof-mounted systems so the optimal tilt angle is 37.74°, but roof-mounted systems are usually mounted flush anyway. When there is a risk of inter-row shading, calculating the optimal tilt angle for area-constrained arrays is a discrete optimization problem (see Section 4.1.1), but studies have found that a tilt angle of 5° to 10° produces the greatest economic benefit.[108] In addition, a small tilt angle is desirable so that debris and precipitation do not accumulate, allowing panels to self-clean. Both ground-mounted arrays and solar canopies with multiple rows were given a tilt angle of 10° as a first-order estimate. Setbacks are clearances around the perimeter, usually for safety purposes, that are measured in terms of distance from the edge. No ordinances specifying setbacks for rooftop PV in Northampton could be found, but DOER recommends a 3-ft (or 4-ft for commercial buildings) clear perimeter on all roofs as well as a 3-ft clear access pathway from the eave to the ridge on each roof slope for pitched roofs.[91] These recommendations were followed when applicable. After inputting all these values, Helioscope calculated the maximum number of modules that could fit in the outlined area (and inside setbacks and around keepouts) and still have the specified surface azimuth and tilt angles. An example of a PV system layout made with Helioscope is shown in Figure 3.1.

In order to maximize the number of modules on each site, modules were placed on multiple sections of some sites. Some sections had different tilt angles due to differences in roof pitch or surface azimuth angle. The number of modules, tilt angle, azimuth angle, and inter-row spacing for all sections of each array, as well as pictures of the system layouts, are included in Appendix A.

3.3.2 Estimating Power Capacity and Energy Production

The capacity for power generation and the amount of annual energy production depended on the number of modules, tilt angle, photovoltaic efficiency, DC to AC conversion losses, latitude, and atmospheric conditions. The number of modules and the tilt angle was based on the system layouts designed in Helioscope. (See Appendix A.) Two different methods were used to estimate the power and energy of the arrays: (1) modeling performance with software and (2) estimating performance using transposition.

Method 1: Modeling Performance with Software

Helioscope was also used to model the system performance based on the system layout, inverter choice, and ambient conditions. The system layouts used to model system performance and calculate power capacity and energy production are in Appendix A.

Helioscope automatically created a wiring configuration based on inverter choice. After selecting the inverter, Helioscope calculated the number of inverters, the number of combiner poles, and wire sizes needed for the array. The inverter chosen for all arrays was the HiQ Solar TrueString 480V (TS480) inverter. The TS480 is a string inverter and was chosen for its high voltage range, low cost, and rugged design; since it could be located outside, it would not need to be housed in an electrical room or shed and thus allowed for more flexible design. Helioscope calculated DC and AC power capacity based on the the manufacturer specifications of the Q.PRO L 310 module and the TS480 inverter.

In order to calculate energy production, performance was modeled under a specific set of ambient conditions. Helioscope comes with a database of weather datasets. Typical-year data from the Solar Prospector tool created by the National Renewable Energy Laboratory (NREL) at Northampton's location, latitude 42.35° and longitude -72.65° was used for these designs. (Typical-year data means one year of hourly data for a typical meteorological year; this data can be thought of as averaged historical weather data.[109]) Helioscope also uses various models to estimate the effects of atmospheric conditions, shading, soiling and reflection on the amount of incident radiation on the tilted array. However, not all the energy incident on the modules is converted into useful electrical energy. Each module has a rated PV efficiency, but the efficiency changes with the cell temperature.[32] Furthermore, there are additional losses due to mismatch in current-voltage characteristics between modules, DC to AC conversion (including inverter efficiency), and wire resistance. Helioscope models all of these effects in order to estimate the annual energy production.

In summary, choosing the inverter and weather data enabled Helioscope to model a system's performance during a typical year and calculate the DC capacity, AC capacity, and annual energy production. The results of performance modeling for all arrays are shown in Table 3.2.

Table 3.2: Power capacity and energy production of arrays based on performance modeling

Site	DC Capacity (kW)	AC Capacity (kW)	Energy Production (MWh/yr)
Ainsworth Gym	129.3	104.0	146.8
Conway House	19.8	16.0	21.7
Cutter-Ziskind	103.2	88.0	123.7
Fort Hill	1280.0	1030.0	1672.0
Parking garage	235.3	192.0	305.5
Tennis court lots	200.3	168.0	253.0
Wright Hall	98.1	88.0	112.6

Method 2: Estimating Performance Using Transposition

The values for power capacity and energy production found through performance modeling were verified with calculations using manufacturer specifications and transposition models based on simple solar geometry. Transposition is the calculation of the insolation, or incident solar energy, on a tilted array by elevating the insolation on a horizontal surface to the plane of the array. Transposition models account for the effects of solar geometry, location and ambient conditions on incident solar energy. The equations used in this section are based on the model used by Duffie and Beckman (1980),[32] which was developed by Liu and Jordan (1963) and extended by Klein (1977).[110] [111] The number of modules and the tilt angles were taken from the same system layouts as those used for software modeling (see Appendix A). All sites were assumed to be in Northampton, MA (42.3° latitude) and under the same weather conditions. All arrays were assumed to have Q PRO L 310 modules and an overall derate factor of 0.77. This derate factor accounted for inverter efficiency, mismatch between modules, wire resistance, and other losses.[112] In order to simplify the calculation, all surface azimuth angles were assumed to be 0° (due south). (This was a very large assumption because many of the arrays did not face due south.) With these assumptions, only the number of modules and the tilt angle affected the annual insolation on the array and the annual energy production.

Before estimating annual energy production, power capacity of the arrays were calculated based on the system layouts and the derate factor. DC capacity was calculated by multiplying the number of modules by the maximum power of one module at STC. The electrical characteristics of the Q.PRO L 310, including the maximum power (P_{mpp}) at STC, are provided in Table 3.3. (For all specifications, see Appendix C.1.) AC capacity was calculated by multiplying DC capacity by the derate factor.

Table 3.3: Electrical characteristics of the Q.PRO L 310 module at STC [2]

I_{sc} (A)	V_{oc} (V)	I_{mpp} (A)	V_{mpp} (V)	P_{mpp} (W)	η_{pv}
9.01	45.84	8.47	36.91	312.5	16.17%

In order to estimate annual energy production, it was necessary to calculate the annual insolation on the surface of the array. First, average daily extraterrestrial insolation on a horizontal surface was calculated for each month ("monthly average daily extraterrestrial insolation"). Daily extraterrestrial insolation is the amount of energy incident on Earth's outer atmosphere during one day, and represents the upper limit of insolation on the surface of Earth. In general, the daily extraterrestrial insolation on a horizontal surface, H_o, can be calculated as follows:

$$H_o = \frac{24(3600)G_{sc}}{\pi}\left[1 + 0.033\cos\left(2\pi\frac{n}{365}\right)\right](\cos\varphi\cos\delta\sin\omega_s + \omega_s\sin\varphi\sin\delta) \tag{3.1}$$

where G_{sc} is extraterrestrial radiation, n is the day-of-the-year, φ is the latitude, δ is the declination, and ω_s is the sunrise/sunset hour angle in radians. (See Appendix D.1 for formulas for δ and ω_s.) Extraterrestrial radiation is the solar radiation incident on Earth before any is absorbed or scattered by the atmosphere and has an annual average value of 1367 W/m^2. It is also called the solar constant because it is more or less constant during the year. Eq. 3.1 was used to calculate the monthly average daily extraterrestrial insolation on a horizontal surface, $\overline{H_o}$ for a given month by using the day-of-the-year in the middle of that month for n.

The clearness index was used to model the influence of atmospheric scattering and absorption due to atmospheric and air mass change on the radiation incident on a horizontal surface. The monthly average clearness index, $\overline{K_T}$, is the ratio defined in Equation 3.2,

$$\overline{K_T} = \frac{\overline{H}}{\overline{H_o}} \tag{3.2}$$

where $\overline{H}$ is the monthly average daily insolation on a horizontal surface and $\overline{H_o}$ is the monthly average daily extraterrestrial insolation on a horizontal surface. Measured data for monthly average daily insolation on a horizontal surface was taken from the NASA Atmospheric Science Data Center.[113] However, it should be noted that the longitude used for obtaining monthly average daily insolation data was +72.6° instead of -72.6°. As a result, it is estimated that insolation was overestimated by about 10%, but possibly up to 20%. (See Appendix D.4.)

The next step was to separate solar radiation into its beam and diffuse components before elevating the insolation on the horizontal surface to the plane of the tilted array. The fraction of diffuse insolation to total insolation on a horizontal surface is a function of the clearness index (see Eq. D.6 in Appendix D.2). Diffuse radiation is assumed to be isotropic, meaning that it has the same magnitude in all directions. Beam radiation, however, is anisotropic, and beam insolation on a horizontal surface is equal to the total insolation on a horizontal surface minus the diffuse insolation. The average direct beam tilt factor, $\overline{R_b}$, which is the gain in beam radiation by tilting the surface, was calculated for each month using Eq. D.7 (see Appendix D.3).

Beam and diffuse components on a tilted surface were added together. Monthly average daily total insolation on a tilted surface, $\overline{H_T}$, is the sum of beam insolation, isotropic diffuse insolation, and insolation diffusely reflected from the ground,

$$\overline{H_T} = \overline{H}\left(1 - \frac{\overline{H_d}}{\overline{H}}\right)\overline{R_b} + \overline{H_d}\left(\frac{1+\cos\beta}{2}\right) + \overline{H}\rho_g\left(\frac{1-\cos\beta}{2}\right) \tag{3.3}$$

where $\overline{H}$ is the monthly average daily insolation on a horizontal surface, $\overline{H_d}$ is the diffuse component of $\overline{H}$, $\overline{R_b}$ is the monthly average direct beam tilt factor, β is the tilt angle, and ρ_g is the ground reflectivity. (See Table D.3 in Appendix D.5 for reflectivity values used.)

Annual insolation was calculated by multiplying the monthly average daily insolation by the number of days in each month and adding up the total for all 12 months. Annual energy production per square meter was calculated by multiplying annual insolation by the PV efficiency, 0.1617, and the derate factor, 0.77. For the same location, annual insolation and annual energy production per square meter were only functions of the tilt angle of the array. Values for annual insolation and annual energy production per square meter for various tilt angles are shown in Table D.6 in Appendix D.7. The tilt angle that yielded the maximum annual insolation, which is the optimal tilt angle for a single panel or a continuous array, was found to be 37.74°.

Finally, annual energy production was calculated by multiplying the number of modules by the area of a single module, 1.93 m^2, and the annual energy production per square meter corresponding to the tilt angle of the array. DC power capacity, AC power capacity and annual energy production calculated for each array using Method 2 is tabulated in Table 3.4. For arrays with multiple sections (see Appendix A), annual energy production was calculated for each section and the sum was the annual energy production of the array.

Table 3.4: Power capacity and energy production of arrays based on transposition

Site	DC Capacity (kW)	AC Capacity (kW)	Energy Production (MWh/yr)
Ainsworth Gym	130.3	100.3	152.5
Conway House	20.6	15.9	26.3
Cutter-Ziskind	104.1	80.1	120.9
Fort Hill	1295.3	997.4	1610.6
Parking garage	237.2	182.6	294.9
Tennis court lots	202.2	155.7	256.1
Wright Hall	98.8	76 .0	114.7

Comparison of Methods for Calculating Power Capacity and Energy Production

Even though two different methods were used to calculate power capacity and energy production, their overall results were in agreement, as shown in Table 3.5.

One notable trend is that software modeling always found higher values for AC capacity than the transposition method. Helioscope found the AC capacity by multiplying the number of inverters times the rated output of the TS480 inverter, 8 kW_{AC}. (See Table 4.1 in Section 4.1.2.) It automatically selected 1.25 as the desired inverter load ratio, and chose the number of inverters to maximize the load ratio without exceeding 1.25. The inverter load ratio is the DC capacity divided by the AC capacity, and an inverter load ratio of 1.25 is consistent with ideal load ratios found by researchers.[114] However, the transposition method calculated the AC capacity by multiplying the DC capacity by a derate factor of 0.77. This is equivalent to assuming an inverter load ratio of 1.30. Since the inverter load ratio for the transposition method was always higher, the AC capacity

Table 3.5: Percent difference between results of software modeling and transposition

Site	DC Capacity	AC Capacity	Energy Production
Ainsworth Gym	-0.8%	+3.6%	-3.8%
Conway House	-4.0%	+0.6%	-19.2%
Cutter-Ziskind	-0.9%	+9.4%	+2.3%
Fort Hill	-1.2%	+3.2%	+3.7%
Parking garage	-0.8%	+5.0%	+3.5%
Tennis court lots	-0.9%	+7.6%	-1.2%
Wright Hall	-0.7%	+14.6%	-1.8%

(+) indicates that indicates that Method 1 (software modeling) yielded a greater value.
(-) indicates that Method 2 (transposition) yielded a greater value.

was always lower.

The only two sites for which the results deviated by more than 10.0% was for Conway House and Wright Hall. The transposition method estimated a higher value for the energy produced by the array on Conway House. One possible reason is that Conway House had the smallest array and the inherent differences between the methods were more pronounced. Software modeling estimated a higher value for the AC power capacity of the array on Wright Hall. The main reason for the discrepancy was that Helioscope was unable to optimize the inverter load ratio for the smallest sub-array, Section 3 (see Appendix A.7). The DC capacity of Section 3 was 24.8 kW. Helioscope chose 3 inverters, which yielded a load ratio of only 1.03; however, if Helioscope had chosen 2 inverters, the load ratio would have been 1.55, which would have exceeded the ideal load ratio of 1.25. For this thesis, the sub-arrays were designed as separate systems in order to model the effects of one roof shading another. However, in practice, the load ratio would probably be higher and the AC capacity would be lower because the sub-arrays could be interconnected.

Even though results of software modeling deviated from the results of transposition for some sites, the values for power capacity and energy production calculated using the different methods were similar overall. Thus it was assumed that the results of the transposition method could be used as inputs for site selection with a high level of confidence.

3.4 Regulatory, Financial and Operational Analysis

While the process of calculating the power and energy produced by an array was nearly the same for all sites, determining (1) how the facility should be connected to the grid, (2) how the off-takers should be compensated, and (3) what financing structure should be used was a complex decision influenced by regulatory and operational constraints and financial incentives. Since the cooperation of local utilities is critical to distributed generation, how a facility is connected to the grid heavily influences how much the customers will be compensated for the energy they produce and which financing structure will provide the most benefits. In addition, regulatory, financial, and operational factors may make the optimum array size less than the maximum size that can fit on a site.

There are several possible options for grid connection, compensation choice, and financing structure. A grid-connected facility can be installed behind an existing meter with an associated load ("behind-the-meter") or as a standalone system behind a new meter with no associated load. Under the SMART program, excess generation can be compensated through net metering or on-bill crediting (which will be considered virtually equivalent for the purpose of this thesis; see Section 1.3.3) or at the buy-all sell-all rate. With net-metering or on-bill crediting, credits for excess generation can be recognized on electric bills and used to offset a load. Alternatively, the excess generation is compensated with direct payments. Financing structures include direct ownership, operating/site leases, power purchase agreements (PPAs), net metering agreements (NMAs), and community-shared solar (CSS). Community-shared solar can be further distinguished between direct-ownership CSS and subscription-based CSS. These financing structures are explained in-depth in Section 1.4.

Three different grid connection, compensation, and financing options for Smith College were identified by analyzing the DOER presentation of the SMART final program design.[1] Although many combinations of grid connections, compensation choices, and financing structures could be imagined, some are not allowed and most were determined to be either impractical or undesirable. For instance, direct ownership, either paid for upfront or through a loan, could be a potential financing option for a for-profit company or a residential customer (including a CSS participant), but is not a good option for Smith College due to its non-profit status. In addition, standalone systems are allowed to sell electricity to the utility at a buy-all, sell-all compensation rate, but Smith may be unable to take advantage of the full value because this revenue stream may be classified as unrelated business income and lead to a tax penalty. Likewise, Smith could not lease the land to a third-party developer to install and maintain this system because the lease payment could be classified as unrelated business income, too. Finally, if Smith participated in a CSS project, the system should not be connected behind one of Smith's meters because it would be unfair for other CSS participants if the credits allocated to their accounts varied based on Smith's electricity usage. The final three options are outlined below.

1. Behind-the-meter, net-metered or on-bill credited PPA
2. Standalone, net-metered or on-bill credited through a third-party developer (i.e. NMA)
3. Standalone, net-metered or on-bill credited CSS

These three options were then matched to the potential sites. In addition, due to the capacity-based compensation rate factors, the array on Fort Hill should be sized to fit comfortably into the 500 kW_{AC} to 1 MW_{AC} size category in order to receive a higher compensation rate. (See Table 1.1 in Section 1.3.3.) In order to increase the compensation rate, a new system layout for Fort Hill was completed. The revised array would still have a tilt angle of 10°, but it would have only 4000 modules, a DC capacity of 1250 kW, and an AC capacity of 962.5 kW and would produce 1554.2 MWh per year. The best combination of grid connection/financing options for each site, as well as any revised estimates of capacity and energy production, are shown in Table 3.6. A choice of compensation cannot be recommended at this time because the future of net metering caps and net metering credits is uncertain and the exact details of how the on-bill crediting mechanism will work have not yet been established by the DPU.

Table 3.6: Grid connection and financing structure recommendations for potential sites

Site	Capacity (kW_{AC})	Energy (MWh/yr)	Grid connection	Financing
Ainsworth Gym	100.3	152.5	Behind-the-meter	PPA
Conway House	15.9	26.3	Behind-the-meter	PPA
Cutter-Ziskind	80.1	120.9	Behind-the-meter	PPA
Fort Hill	962.5	1554.2	Standalone	NMA or CSS
Parking garage	182.6	294.9	Standalone	CSS
Tennis court lots	155.7	256.1	Standalone	CSS
Wright Hall	76.0	114.7	Behind-the-meter	PPA

Ainsworth Gym, Conway House, Cutter-Ziskind, and Wright Hall would be suitable for behind-the-meter PPA. All these sites are located on-campus and are behind the main meter because they are connected to Smith's microgrid. These sites would not be recommended for standalone systems because exported electricity would likely be devalued when net metering credits are calculated. Behind-the-meter systems would allow Smith College to use the power directly and avoid purchasing electricity from the utility at a retail rate that is subject to rising fuel costs. Since the annual energy production of an array on any of these sites is much less than Smith's annual electricity purchases from the utility (about 8,000 MWh/yr), these systems are sized well below the existing load. Uncertainties around the future of net metering and on-bill crediting have little impact on these arrays because their electrons would probably never reach the grid. A PPA is the best financing option for these arrays because a third-party system owner could take advantage of tax incentives like the ITC and MACRS. It may be difficult to get a PPA for Conway House due to its small size, but it could be bundled with arrays on other small buildings (e.g. rental properties). Smith would likely be able to find a developer through a competitive bidding process that could offer a PPA rate that is lower than what Smith is currently paying the utility, \$0.13 per kWh [95], which would lead to net savings on electricity.

A standalone NMA is potentially a good option for Fort Hill. The future of net metering is uncertain, but for the purpose of this thesis, it is assumed that a financing structure similar to existing NMAs could be used with net metering or on-bill crediting in the future. A standalone system would be best for Fort Hill because there is no on-site load. Financing the array with a NMA would be cost-effective because a third-party system owner could take advantage of tax incentives like the ITC and accelerated depreciation. Although Smith could not directly use the electricity produced by the array, Smith could receive net metering credits or on-bill credits that would lower its electric bill by a significant amount; in addition, the SMART program would provide an additional incentive to fill in the gap between the value of the energy and the fixed compensation rate set at the time of interconnection. Solar development at Fort Hill could potentially save the college a lot of money if the rate at which Smith was paying a developer to maintain and operate the system was less than the value of the net metering credits.

The tennis court parking lots and the parking garage are good candidates for standalone CSS. Community-shared solar will get an extra $0.05 per kWh and solar canopies will get an extra $0.06 per kWh during the first block of the SMART program. These adders level the playing field between projects of different sizes, since larger sites benefit from economies of scale. Without these adders, the benefits of developing solar on the tennis court parking lots and the parking garage would not justify the costs. Credits from the electricity produced would be allocated to CSS participants in an agreed-upon manner and lower their electric bills. Smith could choose to receive some of these credits (and therefore be a CSS participant) or instead receive a small lease payment from the developer, which would only slightly lower the incentive for CSS participants. However, the lease payment should be small enough for Smith to avoid tax penalty.

CSS is also an option for Fort Hill, but it would require more administrative work to recruit enough participants. Smith would only be allowed to take up to 50% of the credits and would need to find enough participants to absorb the rest of them. CSS at Fort Hill would get an extra $0.05 per kWh but would not get the solar canopy adder that the tennis court parking lots and the parking garage would be eligible for. In addition, the cost of interconnection at Fort Hill could be high and would likely increase the installed costs, and a developer would be more willing to front these costs for a large, creditable institution like Smith College than for many CSS participants, most of whom would be residential customers.

3.5 Site Selection

Design criteria from Section 2.3 were applied to potential sites with their recommended grid connections and financing structures in order to determine which sites would be recommended for solar development.

Ainsworth Gym, Cutter-Ziskind and Wright Hall were immediately eliminated from the candidates for development because their capacity is greater than 25 kW. Connecting such large arrays to Smith's microgrid could interfere with the cogeneration plant because they would introduce a high degree of variability into the campus demand profile. However, these sites could be good candidates for future on-campus solar development if on-campus energy storage is added or if a way to smooth demand by exchanging with the grid is discovered.

The remaining candidates are Conway House, Fort Hill, the parking garage, and the tennis court lots. Due to the advent of the SMART program, two different types of recommendations will be made: (1) recommendations for short-term development under the SREC II extension and (2) recommendations for long-term development under the SMART program.

3.5.1 Short-Term Development Recommendations

It is likely that Conway House is the only site that could be developed under the SREC II extension. The largest possible array on Conway House would have a nameplate capacity of 21 kW_{DC} and would be eligible for SRECs with an SREC factor of 0.8 under Solar Carve-Out II if it was authorized to interconnect before the effective date of the SMART program.[66] Conway House would be recommended for immediate development, along with other small properties that have already been assessed for solar eligibility (e.g. rental properties). These properties should be bundled together when issuing a request for proposals in order to entice developers.

However, since Conway House has the smallest capacity and produces the least energy, it is also probably the least lucrative option in the long-term, even though SMART program incentives in the future may be worth less than half of what SRECs are worth today. Therefore, it is worthwhile to consider long-term development opportunities under the SMART program that could provide significant benefits over time.

3.5.2 Long-Term Development Recommendations

Fort Hill, the parking garage, and the tennis court parking lots were compared based on feasibility, financial impact, operational impact, environmental impact, and social and educational impact in order to determine the best candidate for long-term development. Conway House was not included in this analysis because it was recommended for development under the SREC II extension and would not be subject to SMART program policies.

Since operational impact was already applied as a constraint, it is not discussed in this section. None of these arrays would be connected to Smith's microgrid, so there would be no interference with the cogeneration plant and the operational impact would be low.

Feasibility

Installing a PV array on the tennis court parking lots would be the most feasible and least risky option. Since the capacity at Fort Hill would be close to 1 MW, it is likely that the interconnection and permitting process could be expensive and time-consuming. In addition, a three-phase power line may need to be extended to reach the array. (This could increase the capital costs by $150 per foot;[115] the implications of higher capital costs are discussed in the next section.) The tennis court parking lots and the parking garage are close to power lines and could be added fairly easily behind new meters.

However, both the tennis court parking lots and the parking garage would involve the construction of solar canopies. This may require separate contracts for the PV installation and canopy construction, which would increase the complexity of the project. The array designer and installer must work closely with the carport vendor to ensure that the electrical aspects of the array are compatible with the structure; thus, it is highly desirable that all parties involved have previous experience with carports. While solar canopies will always add cost and complexity to an array, it is likely that constructing a solar canopy on the parking garage would be more difficult than constructing canopies on the tennis court parking lots. On a parking garage, the columns of the canopy must align with the existing load-bearing structure and a crane is usually used during installation, since most garages cannot bear the weight of the installation equipment.[116] This can be especially challenging if the columns are irregularly placed or if the structure needs to be retrofitted to accommodate the additional weight of the canopies.[117] Additional materials and labor would also increase the installed costs, as discussed in the next section. Nevertheless, it is still predicted that constructing canopies at the parking garage or tennis court parking lots would still be more feasible than extending a three-phase power line to the Fort Hill array.

Financial Impact

Installing a CSS array at either the parking garage or the tennis court parking lots would likely produce the most financial benefits over their lifetimes. Since none of these systems would be owned or operated by Smith College, financial benefits are calculated as the net savings from an array, which would be the difference between the value of net metering credits (which would lower electric bills) and payments to the developer to cover capital and operation and maintenance costs. The financial benefits from the parking garage and the tennis court parking lots were conservatively estimated at $4,000 and $5,000 per year, respectively, and these benefits would be distributed among CSS participants. In contrast, the conservative estimate for CSS at Fort Hill result was a net loss of $30,000 per year. It was predicted that a NMA for Fort Hill would lead to net losses under most scenarios, so it was eliminated from the long-term development candidates. (See Appendix E.5for the results for Fort Hill NMA.) However, these numbers are extremely sensitive to project costs, including the cost of interconnection and the cost of the canopies. Since Fort Hill and the parking garage have some potential feasibility issues, this could increase the final cost and decrease the savings. Based on the available information, the tennis court parking lots were predicted to have the highest probability of producing financial benefits. However, it is likely that all financial benefits are underestimated because this analysis did not take into account the downtrend in installed costs and the cost savings from tax incentives that could be passed on by the third-party system owner.

These estimates were based on a life-cycle assessment of capital costs, operation and maintenance (O&M) costs, and compensation from the SMART program using a discount rate of 6%, followed by a sensitivity analysis of life-cycle benefits to capital costs and SMART program compensation rates. The lifetime of the systems were assumed to be 20 years, equal to the warranty of the PV modules and the term length of SMART program incentives for systems larger than 25 kW_{AC}. The life-cycle financial benefit of the system was expressed as the annual worth over the 20 year lifetime so that the amount could be compared to annual electric bills. The full spreadsheets used to calculate the life-cycle financial benefits are in Appendix E.5.

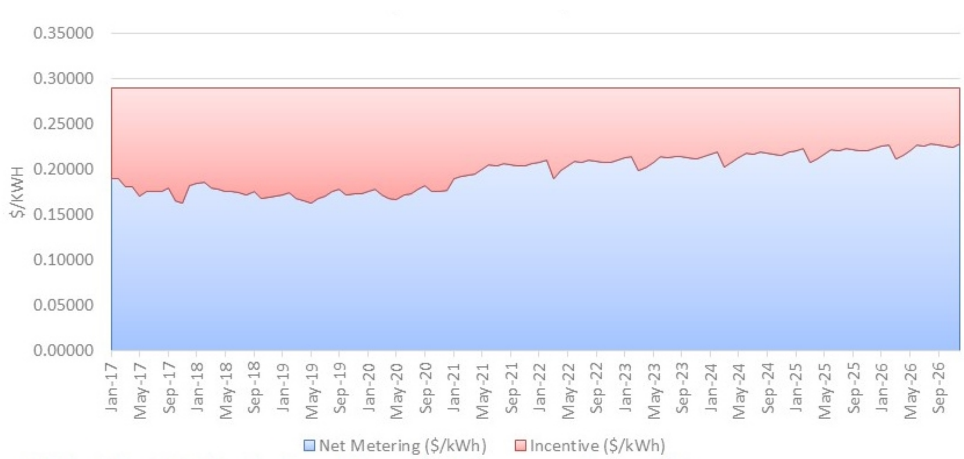
Table 3.7: Estimates of installed costs and O&M costs for PV systems based on DC capacity [3]

Capacity (kW_{DC})	Installed Cost ($/$kW_{DC}$)	O&M Cost ($/$kW_{DC}$)
0-10	$3,897 \pm 889$	21 ± 20
10-100	$3,463 \pm 947$	19 ± 18
100-1,000	$2,493 \pm 774$	19 ± 15
1,000-10,000	$2,025 \pm 694$	16 ± 9

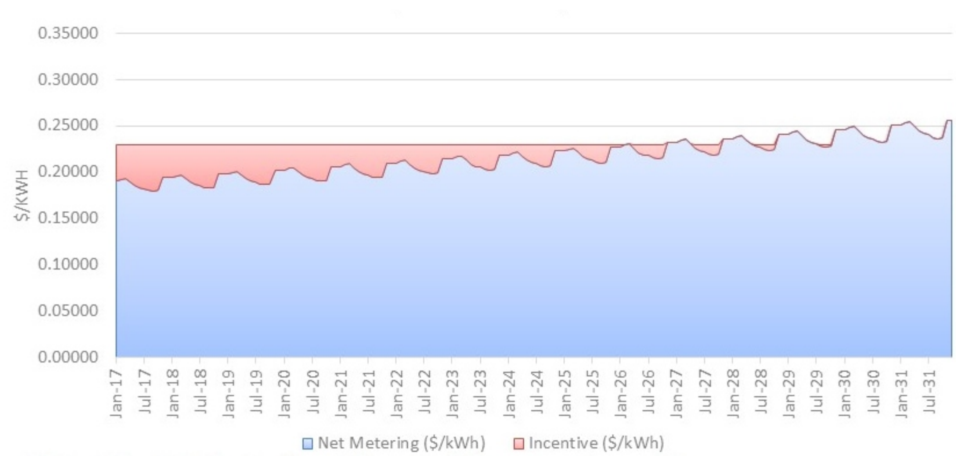
Capital costs and annual O&M costs were based on DC capacity according to NREL estimates of installed cost per kW_{DC} and O&M cost per kW_{DC} for grid-tied PV systems using 2012-2015 data.[3] NREL estimates are shown in Table 3.7, where each parameter is reported as the mean plus or minus the standard deviation. These installed cost estimates were consistent with installed cost benchmarks that included hardware and soft costs but did not include incentives like ITC and MACRS.[118] The capital cost for each system was set equal to the product of its DC capacity and the mean installed cost per kW_{DC} for its capacity range rounded to two significant figures. In addition, carport costs can range from $0.80 per watt to $1.50 per watt, so $1 per watt was added to the capital costs for solar canopies.[119] However, life-cycle benefits were very sensitive to capital costs, so the capital cost was varied by one standard deviation (and rounded to two significant figures) during different trials of the sensitivity analysis. The annual O&M cost for each system was set equal to the product of its DC capacity and the mean O&M cost per kW_{DC} for its capacity range. Due to the small sample of O&M data, the standard deviations for O&M costs were very high and unreliable; as a result, O&M costs were held constant during the sensitivity analysis.

Compensation rates were based on the SMART final program design, which compensated standalone and behind-the-meter systems differently. (See Section 1.3.3 for details.) All systems considered for long-term development would be standalone and net-metered/on-bill credited systems. Accordingly, the SMART program incentive was calculated by subtracting the value of the energy generated from the all-in compensation rate based on the clearing price of competitive procurement, the capacity-based compensation rate factor (based on AC capacity), and any adders for location or project type. As long as the all-in compensation rate was greater than the value of energy, this would result in a fixed compensation rate, since the incentive would essentially fill in the gap between the value of energy and the all-in compensation rate, as shown in Figure 3.2a. The clearing price of competitive procurement was assumed to be $0.11 per kWh, although a clearing price as high as $0.13 per kWh was used in the sensitivity analysis.[65] The value of energy was set equal to the market net metering rate, which was assumed to equal 60% of the retail electricity rate. The retail electricity rate from 2018 to 2037 was extrapolated based on a linear regression of total retail rates in Massachusetts from 1990 to 2016. (See Appendix E.1). Since the value of energy escalates over time, it may eventually exceed the all-in compensation rate, as demonstrated in Figure 3.2b. Thus, the compensation rate was set equal to whichever was greater: the fixed all-in compensation rate under the SMART program or the value of energy. For simplicity, the all-in compensation rate was compared to the value of energy on an annual basis. For each year of the project's lifetime, the compensation rate was multiplied by the annual energy production (assuming no degradation over time) to yield the total annual compensation.

The results of the life-cycle assessment and the sensitivity analysis are shown in Table 3.8, where each bolded and italicized row contains the conservative estimate of the annual worth for the given system. The conservative estimates used a clearing price of $0.11 per kWh, which was the lower end of the predicted clearing prices, and the mean capital cost for the capacity range. Annual worth for Fort Hill was rounded to the nearest $5,000 and annual worth for the tennis



(a) Small standalone, net-metered system



(b) Medium standalone, net-metered system

Figure 3.2: Examples of total compensation rates over time under the SMART program

court parking lots or the parking garage was rounded to the nearest $1,000 to reflect uncertainties; a negative annual worth indicates a net loss and a positive annual worth indicates a net gain. As seen in the table, the life-cycle costs/benefits were most sensitive to the capital costs, but they were also highly sensitive to the clearing price. Since NMA at Fort Hill was predicted to lead to net losses under most scenarios, the results for NMA at Fort Hill are not shown in Table 3.8 but can be found in the full life-cycle assessment spreadsheets in Appendix E.5.

CSS arrays on the parking garage or the tennis court parking lots would most likely have annual benefits of $4,000 and $5,000 per year, respectively. While there would be a small chance that the arrays could result in net losses, CSS on the parking garage could bring benefits of up to $30,000 per year and CSS on the tennis court parking lots could bring benefits of up to $27,000 per year. These benefits would then be distributed among CSS participants in an agreed-upon manner.

Table 3.8: Sensitivity analysis of annual worths of PV systems over 20 year lifetimes to clearing prices and capital costs

Array	Capital Cost ($/$W_{DC}$)	Clearing Price ($/kWh)	Annual Worth ($)
Fort Hill CSS	3.3	0.11	-120,000
Fort Hill CSS	3.3	0.13	-85,000
Fort Hill CSS	***2.5***	***0.11***	***-30,000***
Fort Hill CSS	2.5	0.13	5,000
Fort Hill CSS	1.7	0.11	55,000
Fort Hill CSS	1.7	0.13	90,000
Parking garage CSS	4.3	0.11	-12,000
Parking garage CSS	4.3	0.13	-3,000
Parking garage CSS	***3.5***	***0.11***	***4,000***
Parking garage CSS	3.5	0.13	13,000
Parking garage CSS	2.7	0.11	21,000
Parking garage CSS	2.7	0.13	30,000
Tennis court lots CSS	4.3	0.11	-9,000
Tennis court lots CSS	4.3	0.13	-2,000
Tennis court lots CSS	***3.5***	***0.11***	***5,000***
Tennis court lots CSS	3.5	0.13	13,000
Tennis court lots CSS	2.7	0.11	19,000
Tennis court lots CSS	2.7	0.13	27,000

Environmental Impact

The environmental impact of arrays on Fort Hill, the tennis court parking lots, and the parking garage were estimated to be equal. Both local and global environmental impacts were considered. Installing solar canopies on parking areas would be a good use of existing space, but Fort Hill is an open space that is currently used as outdoor storage space and a tree nursery for Smith's Botanic Garden. In the future, this land could be used for a multitude of purposes and installing a PV array would restrict land use for at least 20 years. On the other hand, Fort Hill would produce the most energy and it could be argued that the electricity is replacing electricity produced from carbon-emitting fuels. If the annual electricity production at Fort Hill, the tennis court lots, and the parking garage was multiplied by 0.292 metrics tons of CO_2 equivalent per kWh,[97] then the annual "emissions reductions" of these arrays would be 454 tons, 86 tons, and 75 tons, respectively. (However, it must be noted that these emissions reductions could not be counted towards Smith's greenhouse gas emissions reporting unless Smith owned the RECs, which would be difficult or impossible under the SMART program.) While climate change mitigation was considered important, the Fort Hill array involved local environmental trade-offs that were not an issue for the arrays at the parking garage and tennis court parking lots. Therefore the environmental impact rating was considered to be equal across the three sites.

Social and Educational Impact

The tennis court parking lots and the parking garage arrays would have the highest social impact. They are located on the edge of campus, but they are visible to the community, especially to those with cars. These arrays could also provide a social service to the campus by covering the parked cars from rain and snow.

In addition, CSS would increase access to the benefits of solar energy and allow CSS participants to lower their electric bills. For example, if $4,000 were distributed among 30 participants, then they could each save about 10% on their electric bill in the first year, assuming that each participant's electricity consumption is comparable to the state average. (See Appendix E.6.) However, if $30,000 were distributed among 30 participants, then they could each save up to 84% on their electric bill in the first year. Smith could either choose to be a CSS participant and take up to 50% of the credits or to receive a site lease that would slightly reduce the benefits for CSS participants.

Finally, data monitoring could be incorporated into all three arrays and enhance their educational value. Similar to UMass Amherst (see Section 1.5), Smith could negotiate with the developer to install high-resolution data monitoring equipment. This data could be accessed by faculty and students and used for coursework or research. In addition, these arrays could be added to Smith's existing energy dashboard website and used to inform the Smith community about the impact of renewable energy. Educational impact is also a kind of social impact but it was considered equal across all three arrays.

Final Long-Term Development Recommendations

Community-shared solar arrays on the parking garage and the tennis court parking lots were determined to be the best candidates for long-term solar development under the SMART program. A large standalone system like Fort Hill would receive less financial compensation and would be a riskier investment because the interconnection process would likely be long and expensive. In addition, solar canopies on parking areas would be a socially and environmentally responsible use of existing space and would protect cars from rain and snow. Solar arrays on the parking garage and the tennis court parking lots would also be more visible to Smith's community than an array at Fort Hill. Finally, CSS increases access in Smith's community to the benefits of solar energy and is an innovative financing structure that would make Smith stand out from its peers. The results of this comparison are summarized in Table 3.9, where + indicates positive rating, +/- indicates a neutral rating, and - indicates a negative rating for each criterion.

Table 3.9: Application of design criteria to long-term development candidates

Project	Feasibility	Financial impact	Environmental impact	Social impact
Fort Hill NMA	-	-	+/-	-
Fort Hill CSS	-	+/-	+/-	+
Parking garage CSS	+/-	+	+/-	+
Tennis court lots CSS	+	+	+/-	+

Based on available information about the SMART program, the parking garage and the tennis court parking lots would be recommended for further consideration for solar development. While it was predicted that the solar canopy on the tennis court parking lots would be less complicated and less expensive to install, additional work would be needed to confirm this. It is likely that these estimates are too conservative since they do not account for declining installed costs of solar over time or the cost savings from the ITC and MACRS passed on by third-party system owners. In addition, since the details of the SMART program were not finalized at the time of writing this thesis, it would be recommended that DOER and DPU updates to the SMART program be monitored closely since the incentives would influence the feasibility and costs of the arrays.

Chapter 4

Detailed Design for Parking Garage

The parking garage was one of the sites recommended for long-term solar development because it would be compatible with Smith's cogeneration plant and provide significant financial, environmental, and social benefits to the Smith community.

However, this recommendation was based on a preliminary design. Completing a detailed design was determined to be the next logical step towards development. The detailed design included a more site-specific array sizing process, wiring configuration, wire sizing, and a more accurate estimation of life-cycle costs. However, in practice, Smith College and other institutions interested in solar development should issue a request for proposals after completing site selection and work with developers to create a detailed design that meets their needs and constraints.

4.1 Array Sizing

In Section 3.3.1, a tilt angle of 10° was given to the array on the parking garage as a first-order estimate. In this section, the actual optimal tilt angle for the parking garage was determined via discrete optimization. After determining this optimal tilt angle, a new system layout was designed and the number of modules, power capacity and energy production were recalculated.

4.1.1 Tilt Angle Optimization

The optimal tilt angle is different for PV arrays mounted on tilted surfaces like a pitched roof and for those on horizontal surfaces. Based on the latitude and climate of Northampton, MA, the optimal tilt angle for a single panel is 37.74°. (See Appendix D.7.) In a roof-mounted array, panels are usually mounted flush to the roof and placed nearly edge to edge, with a small separation for clamping hardware. Inter-row shading is not a concern, and the optimal roof pitch is equal to the optimal tilt angle for a single panel.

In contrast, PV arrays on horizontal surfaces, such as flat roofs and open land, are often mounted in rows at a fixed tilt and the risk of inter-row shading complicates the process of determining the optimal tilt angle. Studies have found that for area-constrained PV arrays, a tilt angle of of 5° to 10°produces the greatest economic benefit, which is much lower than the optimal tilt angle for a

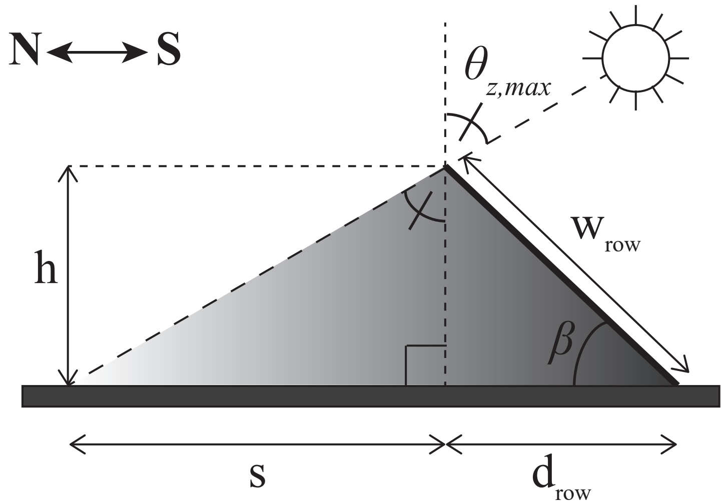


Figure 4.1: Side view of panel geometry and solar geometry on the winter solstice.

single panel.[108] This goes against the conventional wisdom that solar panels should be mounted perpendicular to incident radiation, but makes sense when trade-offs between increasing the tilt angle and maximizing the number of modules are considered.

Rows must be spaced so that they do not shade each other and decrease the energy production of the array, and rows must be spaced farther apart as the tilt angle increases because each row projects a longer shadow. Inter-row spacing is conventionally calculated based on the solar zenith angles on the winter solstice.[120] For this thesis, it was assumed that the shade-free window would be four hours long. In Northampton, MA, the solar zenith angle at 10 a.m. and 2 p.m. solar time on December 22 is 67°.

For this assessment, the inter-row spacing, s, was set equal to the length of the shadow when $\theta_z = \theta_{z,max} = 67°$, which was calculated according to Equation 4.1,

$$s = w_{row} \sin\beta \tan\theta_{z,max} \tag{4.1}$$

where w_{row} was the row width, β was the tilt angle, and $\theta_{z,max}$ was the maximum solar zenith angle without shading the row behind. Figure 4.1 shows a side-view of a tilted panel with distances and angles labeled. As seen in the figure, the row depth, d_{row}, is the projection of the row width onto the horizontal surface.

Assuming that the array would be area-constrained, the tilt angle was chosen in order to maximize the energy production on the available area. For a given horizontal surface, there were two extremes: flat ($\beta = 0°$) and vertical ($\beta = 90°$). A flat array would have no inter-row spacing because there would be no shading, and thus more panels could fit onto the available area because panels could be installed nearly edge-to-edge. However, a flat array would also collect precipitation and debris, which would be especially undesirable (and potentially dangerous) in regions with snowy winters. On the other hand, an array whose tilt angle approached 90° could theoretically fit an in-

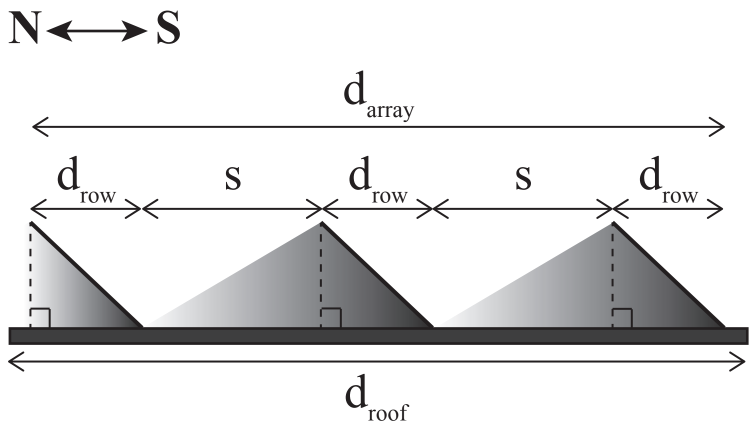


Figure 4.2: Side view of rows and inter-row spacing across the array.

finite number of modules onto the available area. In this extreme, all the panels would be mounted in a single row and thus inter-row spacing would be eliminated, although the array would cast a very long shadow behind it. Of course, it would be impossible to construct an array with an infinite number of panels, and as tilt angle increased, the array would become increasingly unstable.

The optimal tilt angle for an array with inter-row spacing was in between these two extremes and was determined via discrete optimization. The parking garage was used as a case study, since the dimensions of the site and the dimensions of the panels influence how many rows can fit on the available area. For simplicity, it was assumed that the roof of the parking garage was exactly 64 m (east-west) by 40 m (north-south), that each module needed an area of 2 m by 1 m (including space for clamps), that the solar panels covered the entire area, and that the array faced due south.

Discrete optimization was performed by calculating the optimal tilt angle, annual energy production, and row height for every possible combination of number of rows and number of modules across the width of the row ("number of modules per row"). Rows were oriented east-west so that the panels, when tilted, would face due south. The minimum number of rows was 2 and the maximum number of rows was 38. (The number of rows was constrained to be more than 1 and less than 40 because the maximum tilt angle for a single row was 90° and the maximum tilt angle for 40 rows was 0°, which were the two extremes.) As a result, the minimum number of modules per row was 1 and the maximum number of modules per row was 19.

The number of panels that can fit on a given area was constrained by the width of the roof according to the following equation:

$$d_{array} = n_{row} d_{row} + (n_{row} - 1)s \leq d_{roof} \tag{4.2}$$

where d_{array} was the projection of the total array width onto the horizontal surface, n_{row} was the number of rows, d_{row} was the projection of the row width onto the horizontal surface, and s was the inter-row spacing calculated in Equation 4.1. This geometry is demonstrated in Figure 4.2.

For given numbers of rows and modules per row, the tilt angle was optimized to yield the maximum annual energy production and was constrained by the width of the roof. In Equation 4.1, inter-row spacing was found to be a function of row width, tilt angle and the maximum solar zenith angle. The length of the projection of the row onto a horizontal surface is also a function of row width and tilt angle,

$$d_{row} = w_{row} \cos\beta \tag{4.3}$$

where w_{row} is the row width and β is the tilt angle. By substituting Equations 4.1 and 4.3 into Equation 4.2, a new equation for the projection of the array width onto the horizontal surface was found,

$$d_{array} = n_{row} w_{row} \cos\beta + (n_{row} - 1) w_{row} \sin\beta \tan\theta_{z,max} \leq d_{roof} \tag{4.4}$$

where d_{array} was projection of the array width onto the horizontal surface, n_{row} was the number of rows, w_{row} was the width of a single row, β was the tilt angle, $\theta_{z,max}$ is the maximum solar zenith angle, and d_{roof} was the width of the horizontal surface (measured north-south). The total width of the roof, d_{roof}, was 40 m. The row width, w_{row}, measured in meters had the same value as the number of modules per row, since the width of a single module was 1 m. For a given number of rows and a given row width, the projection of the array width increased as the tilt angle increased because while the projected width decreased, the inter-row spacing increased more. Thus, the tilt angle reached a maximum when the projection of the total array width onto the horizontal surface was equal to the width of the horizontal surface. For every combination of rows and modules per row, the tilt angle that yielded the maximum annual energy production was the maximum tilt angle if the maximum tilt angle was less than 37.74° or 37.74° if the maximum tilt angle was greater than 37.74°.

The annual energy production at the maximum tilt angle for each combination of rows and modules per row was calculated according to the transposition method described in Section 3.3.2. The total number of modules for each combination was equal to the number of rows multiplied by the number of modules across the row width and the number of modules across the row length. For all combinations, the number of modules across the row length was thirty-two because thirty-two 2 m-long modules could fit onto the 64 m-long roof. Multiplying the total number of modules by the area of a single module, 1.93 m^2, and the annual energy production per square meter corresponding to the maximum tilt angle yielded the annual energy production.

The height of the array was equal to the height of a single row, h, which was calculated according to the following equation:

$$h = w_{row} \sin\beta \tag{4.5}$$

where w_{row} was the width of a single row and β was the tilt angle. Since the row height increased as the tilt angle increased, maximizing the tilt angle also maximized the row height. The height must be greater than zero if the array is not flat, but a large height could cause the array to be unstable and would not be aesthetically pleasing.

The results of the discrete optimization found that the arrays that produced the most energy were those with the greatest total number of modules. None of the top-performing arrays had a tilt

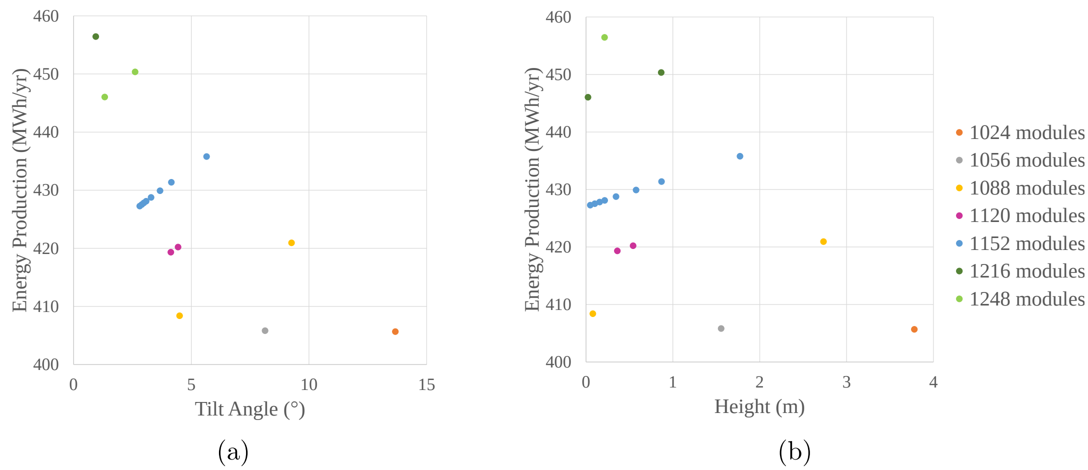


Figure 4.3: Plots of (a) annual energy production versus tilt angle and (b) annual energy production versus height by the total number of modules

angle of 37.74°. The same total number of modules can be achieved for different combinations of number of rows and number of modules per row. For the same number of modules, annual energy production increased as maximum tilt angle increased and the number of rows decreased, but the maximum annual energy production was reached when either the tilt angle reached 37.74° or the number of rows reached 2 (if the maximum tilt angle was less than 37.74°). Since the number of rows and number of modules per row was constrained by the width of the roof, certain "sweet spots" emerged that were not predicted before the discrete optimization was performed. Figure 4.3 shows the annual energy production of the all possible combinations that produced more than 400,000 kWh per year. As seen in the figure, only one of the top-performing arrays had a tilt angle greater than 10° or a height greater than 3 m.

Based on the results of the discrete optimization and the geometry of the parking garage, the optimal tilt angle for the parking garage would be 2.6° with 2 rows, each 19 modules across. This configuration would look similar to the PV array pictured in Figure 4.4.

4.1.2 Estimating Number of Modules, Power Capacity and Energy Production

After determining that 2.6° would be the optimal tilt angle for the parking garage, a new PV system layout was completed for the parking garage in Helioscope using the process described in Section 3.3.1. The Q.PRO L 310 was used as the PV module and the HiQ TrueString 480V (TS480) was used as the inverter. The rugged design of the TS480 inverter made it ideal for the all-weather conditions of a carport. The inverter specifications are shown in Table 4.1. (The module specifications can be found in Tables 3.1 and 3.3. For all component specifications, see Appendix C.) Carports were selected for the racking and no setbacks were used since the roof of the parking garage would still be fully accessible in the case of an emergency.

The maximum number of modules in the redesigned array was 1072. The specifications of the

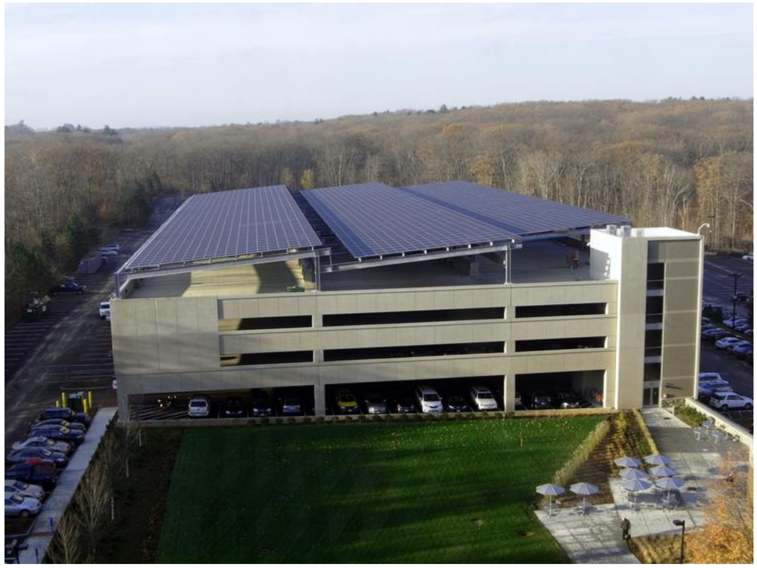


Figure 4.4: The PV array at Staples' headquarters in Framingham, MA is an example of a solar carport on a parking garage.

Table 4.1: Electrical characteristics of the HiQ Solar TrueString 480V inverter [4]

$I_{DC,max}$ (A)	$V_{DC,mpp}$ (V)	$V_{DC,oc}$ (V)	$P_{AC,max\,out}$ (kW)	η_{inv}
10	425-850	1000	8	98.0%

new array are shown in Table 4.2 and a picture of the PV system layout is shown in Figure 4.5. The inter-row spacing within each section was approximately 0.0 m, but the spacing between Section 1 and Sections 2 and 3 was about 2 m.

Table 4.2: Detailed design specifications of PV array on the parking garage

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	496	Landscape	2.6	-18	0.0
Section 2	180	Landscape	2.6	-18	0.0
Section 3	396	Landscape	2.6	-18	0.0

Power capacity and energy production were estimated using both methods outlined in Section 3.3.2. The results of both modeling performance with Helioscope and estimating performance using transposition are compared in Table 4.3.

Table 4.3: Comparison of power and energy for parking garage calculated by two different methods

Method	DC Capacity (kW)	AC Capacity (kW)	Energy Production (MWh/yr)
Software modeling	332.3	272.0	413.5
Transposition	335.0	258.0	397.0

Figure 4.5: PV system layout on the parking garage with numbered sections.

4.2 Wiring Configuration

In order to complete a wiring configuration, the number of modules in series and the number of parallel strings was determined based on the electrical characteristics of the module, the electrical characeristics of the inverter, and the maximum number of modules that could be installed on the site.

The array was first divided into two sub-arrays: Section 1 in Figure 4.5 became the upper sub-array and Sections 2 and 3 became the lower sub-array. The maximum number of modules in the upper sub-array was 496 and the maximum number of modules in the lower sub-array was 576.

For each sub-array, the number of modules in series was constrained by the following equation,

$$V_{inv,DC,mpp,min} \leq N_{series} V_{PV,DC,mpp} \leq V_{inv,DC,mpp,max} \tag{4.6}$$

where N_{series} was the number of modules in series, $V_{PV,DC,mpp}$ was the voltage of the PV module at the maximum power point, and $V_{inv,DC,mpp,min}$ and $V_{inv,DC,mpp,max}$ were the lower and upper voltage limits, respectively, for the maximum power range of the inverter. The number of modules in series was also constrained by the equation,

$$N_{array} = N_{series} N_{parallel} \leq N_{array,max} \tag{4.7}$$

where N_{array} was the number of modules in the array, N_{series} was the number of modules in series in each string, $N_{parallel}$ was the number of strings in parallel, and $N_{array,max}$ was the maximum number of modules in the array and all four numbers were limited to integers. In this case, the number of modules in each sub-array was used instead of the total number of modules in the array.

This was another example of discrete optimization. In this case, $V_{PV,DC,mpp}$ was 36.91 V, $V_{inv,DC,mpp}$ was between 425 V and 850 V, and $N_{array,max}$ was 496 for the upper sub-array and 576 for the lower sub-array. The number of modules in series had to be equal for both sub-arrays since they would be connected in parallel. Each sub-array had the greatest number of modules when the number of modules in series was 16, so that automatically yielded the highest number of modules for the total array. When the number of modules in series was 16, the number of strings in the upper sub-array was 31 and the number of strings in the lower sub-array was 36 for a combined total of 67 strings. The total number of modules in the array was 1072. The wiring configuration for this array is shown in Figure 4.6.

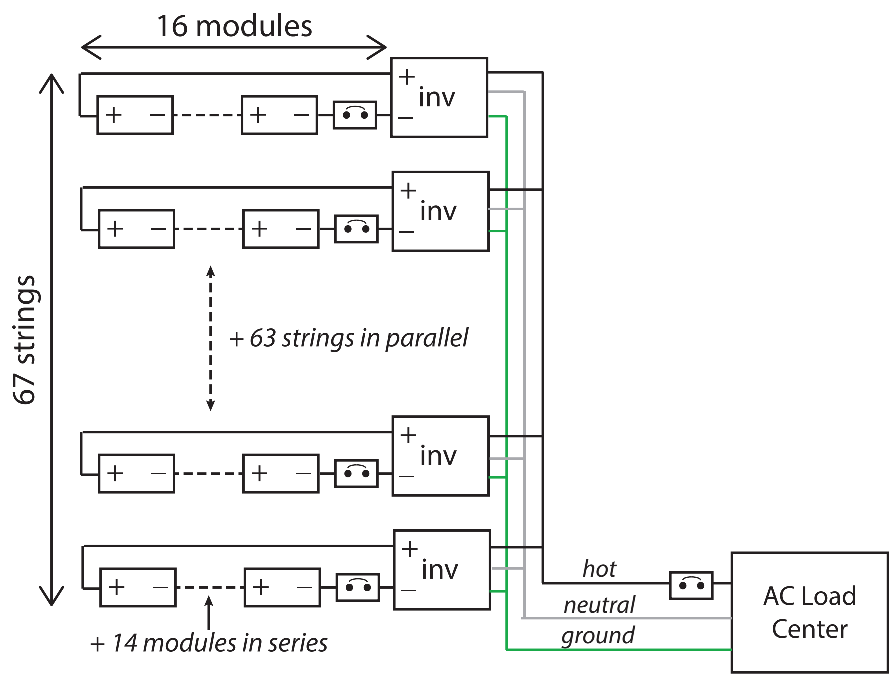


Figure 4.6: Wiring diagram of parking garage PV array up to AC load center (grid interface).

Finally, it was verified that the maximum current, voltage and power ratings of the inverter wouldn't be exceeded by this array. The maximum DC current in one string was equal to the short-circuit current of a single module, 9.01 A, which was less than the maximum DC current rating for the inverter, 10 A. The maximum voltage across one string was equal to the open-circuit voltage across the string, $V_{string,oc}$,

$$V_{string,oc} = N_{series} V_{PV,oc} \tag{4.8}$$

where N_{series} was the number of modules in one string and $V_{PV,oc}$ was the open-circuit voltage of the module. The maximum voltage was found to be 733 V, which is less than the open-circuit voltage of the inverter, 1000 V. The maximum power in one string, $P_{string,DC,mpp}$, was determined by the following equation,

$$P_{string,DC,mpp} = N_{series} I_{PV,DC,mpp} V_{PV,DC,mpp} \tag{4.9}$$

where N_{series} was the number of modules in series in one string, $I_{PV,DC,mpp}$ was the DC current at the maximum power point of the module, and $V_{PV,DC,mpp}$ was the DC voltage at the maximum power point of the module. For this configuration, the maximum power in one string would be 5.0 kW, which is less than the maximum power rating of the inverter, 8 kW. Therefore the inverters should not be damaged by this array.

4.3 Wire Sizing

Wire sizes were estimated because the cost of wire was needed for the life-cycle cost assessment and the cost depends on the gauge. Each wire was sized based on its length, the voltage across the wire and current it would carry. The system voltage, $V_{array,DC}$, was equivalent to the voltage drop at maximum power across one string,

$$V_{array,DC} = N_{series} V_{PV,DC,mpp} \tag{4.10}$$

where N_{series} was the number of modules in series in one string and $V_{PV,DC,mpp}$ was the DC voltage at the maximum power point of the module. For this array, the system voltage was about 591 V. The DC current in one string is equal to the DC current of the module at maximum power, 8.47 A. The total AC current of the array, $I_{array,AC}$, was calculated using Equation 4.11,

$$I_{array,AC} = \eta_{inv} I_{array,DC} = \eta_{inv} N_{parallel} I_{PV,DC,mpp} \tag{4.11}$$

where η_{inv} was the inverter efficiency, $I_{array,DC}$ was the total DC current of the array, $N_{parallel}$ was the number of strings in parallel, and $I_{PV,DC,mpp}$ was the DC current of the module at maximum power. (The full derate factor was not used because some power losses occur post-inverter, and using a higher current increased the factor of safety.) Thus the AC currents of the upper and lower sub-arrays were 257 A and 299 A, respectively, and the total AC current of the array was about 556 A.

Voltage, current and wire length were used to determine the necessary sizes of the pre-inverter and the post-inverter wires. The post-inverter wire sizes were determined separately for the upper and lower sub-arrays since they wouldn't be combined until reaching the AC load station. The check necessary wire thicknesses were determined according to Equation 4.12, derived from Ohm's law,

$$d = \sqrt{n \frac{4\rho L}{\pi} \frac{I}{V_{drop}}} \tag{4.12}$$

where d is the diameter of the wire, n is the safety factor, ρ is the resistivity of the wire material, I is the current through the wire, and V_{drop} is the voltage drop across the wire. The wires were assumed to be made of annealed copper, which has a resistivity of $1.724 \times 10^{-8}\Omega \cdot m$ or $5.656 \times 10^{-8}\Omega \cdot ft$ at 20°C.[121] In addition, the voltage drop across the wire was assumed to be 2% of the system voltage and safety factor of 1.5 was used. The spreadsheet used to calculate wire sizes is shown in Appendix F.1.

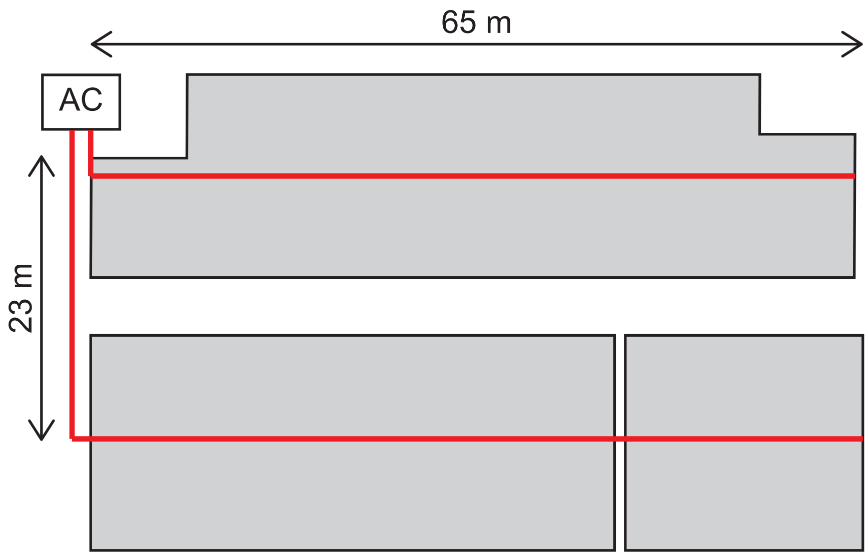


Figure 4.7: Layout of the post-inverter wires, represented in red, for the parking garage array.

The pre-inverter wire is the wire connecting a single string of modules before converting the current from DC to AC. For this array, it would need to be 16-32 m (52.5-105 ft) long to connect 16 modules in series, depending whether the modules were oriented portrait or landscape. A length of 32 m (105 ft) was used as a conservative estimate. This length was calculated by multiplying the length of a single module, 2 m, by 16 to get the total one-way distance along a string. A wire that could have a voltage of 591 V, a DC current of 8.47 A, and a length of 105 ft should have a thickness no less than 20 awg. However, the thickness was increased to 18 awg because 20 awg wire with a voltage rating of 600 V was not found. Since there would be 67 parallel strings, at least 7035 ft of 18 awg wire would be needed.

The post-inverter wire is the wire connecting all the parallel strings and the load center after the current is inverted to AC. As seen in Figure 4.7, the length of the post-inverter wire was about 65 m (213 ft) for the upper sub-array and 88 m (289 ft) for the lower sub-array. Since the AC currents for the upper and lower sub-arrays were 257 A and 299 A, respectively, the minimum wire thickness of the post-inverter wire was 1/0 awg for the upper sub-array and 2/0 awg for the lower sub-array. However, 2/0 awg could safely be used for both arrays, so the total length of 2/0 awg needed would be 502 ft.

4.4 Life-Cycle Cost Assessment

The life-cycle cost assessment for the detailed design of the parking garage followed a similar method to the previous life-cycle cost assessment in Section 3.5.2. A 20 year lifetime was assumed and a discount rate of 6% was used. The primary difference was that hardware costs were calculated based on unit prices, rather than on a per-watt basis.

Capital costs included both the costs of hardware and soft costs. The cost of hardware, except for the carport structure, was based on unit prices, as shown in Table 4.4. The cost of the carport structure and soft costs, including installation labor and overhead, were based on the DC capacity, 335 kW. As in Section 3.5.2, $1 per watt was added to the capital costs for solar canopies.[119] Soft costs per watt were based on NREL benchmarks for commercial 200 kW systems in 2015.[118] By subtracting the module, inverter, racking, and other balance of system costs from the total installed cost reported by NREL, the soft costs were estimated to be $1.01 per watt.

Table 4.4: Component specifications with costs (carport structure not included)

Component	Unit Price	Amount	Total Cost
Hanwha Q.PRO L 310	$271.00 [2]	1072	$290,512.00
HiQ Solar TrueString 480V	$1,475.00 [4]	67	$98,825.00
Platt 18 awg, TFFN, Stranded Copper, 600 V	$0.07/ft [122]	7035 ft	$492.45
Platt 2/0 awg, THWN-2, Stranded Copper, 600 V	$2.37/ft [123]	502 ft	$1,189.74

Operation and maintenance costs and compensation were calculated according to the method used in Section 3.5.2. It was assumed that the annual O&M costs would be $19 per kW. The compensation rate was based on its AC capacity, 258 kW. Since the capacity was greater than 250 kW, the capacity-based compensation rate factor decreased from 150% to 125% of the clearing price. The system would also be eligible for adders of $0.05 per kWh for CSS and $0.06 per kWh for solar canopies. It was assumed that the clearing price would be $0.11 per kWh and that the array would produce 397 MWh per year without degradation.

It was estimated that the system would have an annual net cost of $906.99, with a present worth of $10,403.13 over the 20 year lifetime. The full summary is shown in Table 4.5, where benefits are positive and costs are negative. However, if the capacity-based compensation rate factor was 150% instead of 125%, the system would lead to annual savings of $10,010.18, with a net present worth of $114,815.99. Therefore, if the system was resized to have an AC capacity less than 250 kW, then the system would most likely provide a net financial benefit.

Table 4.5: Life-cycle cost summary for the parking garage

Item	Annual Worth	Present Worth
Capital	-$92,796.56	-$1,064,369.19
O&M	-$6,365.00	-$73,006.05
Compensation	$98,254.56	$1,126,972.11
Net cost/benefit	**-$906.99**	**-$10,403.13**

Chapter 5

Conclusions and Future Work

5.1 Conclusions

The initial goals of this thesis were (1) to design a new photovoltaic array located on Smith College property and (2) to propose a model for financing and implementing the design in a way that complies with the current regulatory framework and provides the most benefits to the Smith community. Ultimately, two different sets of recommendations were made for short-term and long-term solar development.

In the short-term, it is recommended that Smith College pursue power purchase agreements for roof-mounted arrays on Conway House and other small buildings such as rental properties. These arrays would be less than 25 kW and could be installed without placing an excessive burden on the cogeneration plant if installed behind the main meter or receive standard net metering credits if installed behind a smaller meter. It is also feasible to install and start operating these arrays before the start of the new SMART program, which will likely be March 31, 2018 or later.

In the long-term, it is recommended that Smith College pursue developing community-shared solar canopies at either the parking garage or the tennis court parking lots. These arrays would fit the needs of the Smith community best because they would be feasible, have high visibility, make good use of existing spaces, lower the electric bills of Smith community members (net savings are conservatively estimated at \$4,000 to \$5,000 per year), and provide an additional social benefit by covering parked cars. In addition, they would not interfere with the operation of the cogeneration plant.

To kickstart the process of long-term solar development, a detailed PV system design was completed for the parking garage. The optimal tilt angle of the array was determined to be 2.6° via discrete optimization and the system layout was redesigned with the new tilt angle. After determining the series and parallel configurations and sizing the wires, a more detailed life-cycle cost assessment based on unit prices was conducted and found that the parking garage would have an annual net cost of \$906.99. The costs exceeded the benefits because the 258 kW_{AC} system was just above the 250 kW_{AC} limit for receiving a compensation rate factor of 150%. If the capacity-based compensation rate factor was 150% instead of 125%, the system would lead to annual savings of

\$10,010.18. Therefore, if the system was resized to have a capacity less than 250 kW_{AC}, then the system would most likely provide a net financial benefit.

However, conclusions were made from this work that went beyond the recommendations of individual sites. Rather, this thesis was the first step towards creating a decision-making framework for choosing sites and financing structures for future solar development that focused on the interplay between technical design and regulatory, operational and financial constraints. This decision-making framework was applied to Smith College as a case study after identifying key constraints and interests for the college and its community members.

Key constraints for Smith College are its historic campus, its energy infrastructure, and its non-profit status. Smith's historic buildings are part of what makes the college unique. However, many of the roofs are not suitable for solar development because they are made of slate, may need replacement in the near future, or are simply too small. Most of Smith campus is behind the main meter and gets electricity from the cogeneration plant. Adding more solar behind the main meter is currently not within Smith's operational capacity because PV arrays introduce variability into the electricity demand of the campus and interfere with the smooth operation of the cogeneration plant. Finally, Smith's non-profit status makes working with a third-party system owner attractive because Smith cannot directly take advantage of tax incentives. In addition, some financing structures are not as desirable for Smith because it can accept only a small amount of unrelated business income before it risks a tax penalty.

These constraints have important implications for which sites are good candidates for solar development. This narrows the options to off-campus sites that are served by smaller meters. If there is a behind-the-meter load, then the college should pursue a power purchase agreement with net metering; the array would be load-limited and should be sized to match the load. If market net metering rates continue, the array would actually need to be sized so that peak production in the summer matches the load, which would reduce the size of the array. If the on-site load is parasitic or negligible, then the college could pursue a net metering agreement for a standalone system; the array would be area-constrained and should be sized to maximize energy production. However, under the new Solar Massachusetts Renewable Target (SMART) program, excess generation will be devalued and standalone systems either must be very large or be eligible for additional incentives (e.g. community-shared solar, brownfield, solar carports) in order to be economically justifiable. The additional incentives help to level the playing field between small arrays and large arrays that can take advantage of economies of scale.

The long-term recommendations would have been very different if it was possible to add solar behind-the-meter and if renewable energy certificates could be owned by entities like Smith under the new SMART program. If solar could be added behind-the-meter, on-campus sites like Ainsworth Gym, Cutter House, Wright Hall, and Ziskind House would all be excellent candidates for solar power purchase agreements. In addition, a power purchase agreement or a net metering agreement with the option to purchase the system partway into the contract term would be more attractive if Smith could own the renewable energy certificates and use them to lower its carbon footprint. However, renewable energy certificates will be automatically transferred to suppliers when the SMART program comes into effect. Thus, due to regulatory, financial, and operational constraints, community-shared solar arrays on parking areas were determined to be the best options for solar development.

5.2 Future Work

This thesis created a decision-making framework for solar development for Smith College and other mission-driven, non-profit institutions. However, the recommendations made should be reevaluated as the Department of Energy Resources and Department of Public Utilities make revisions to the SMART program and net metering policy. Future work would include repeating transposition calculations with the correct insolation data and improving the estimates of annual energy production. (See Appendix D.4.) It is estimated that annual energy production was overestimated by about 10%, but possibly up to 20%. A more realistic life-cycle cost assessment and sensitivity could also lead to different results and different recommendations for solar development. In addition, the detailed design of the parking garage array could be expanded and a detailed design for the tennis court parking lots should be completed. It is likely that which system to develop would be clearer once a detailed design is completed for both community-shared solar arrays. Finally, more sites could be explored for solar development. For instance, the large lot on Fort Hill was considered for solar development in this thesis, but the nearby Center for Early Childhood Education was not.

The results of the life-cycle cost assessments in this thesis were likely too conservative. If more realistic assumptions were made about capital costs, the estimated capital costs would likely decrease and the net benefits would increase. First, the life-cycle cost assessment in this thesis was based on installed costs in 2015. These numbers are already outdated, and assuming that the installed costs of solar continue to decline, this thesis overestimates installed costs for future years when these systems would actually be developed even more. Installed cost estimates could be improved by using more recent data, although reliable sources can be hard to find. Alternatively, a model based on historical trends could be created to project installed costs in the future. Second, this thesis did not account for the savings from the investment tax credit and accelerated depreciation that would be passed on by third-party system owners to off-takers like Smith College. These are some of the most valuable incentives for solar energy but they are not directly accessible to a non-profit institution like Smith College. Since more administrative work is required when developers are responsible for asset management as well as installation, it is likely that the full value of the tax incentives would not be passed onto Smith College. However, a more sophisticated sensitivity analysis would include the net benefit if different fractions of the tax incentive were passed down: 100%, 50%, 0%, etc. Alternatively, a literature review could be conducted to investigate how third-party system ownership affects the cost savings associated with tax incentives. The results of this literature review could be used to estimate how much the capital costs should be reduced in the life-cycle cost assessment. These adjustments would lead to a higher and more realistic estimate of the net benefits of all arrays.

Future work on the detailed design of the parking garage could include developing a quantitative component selection process and researching solar carport designs. The Hanwha Q Cells Q.PRO L 310 module and the HiQ Solar TrueString 480V inverter were used throughout this design, but the module and inverter should be chosen specifically for each detailed design. A quantitative process for determining which module and inverter is best for different types of arrays could be developed. For example, it would be important to consider the advantages and disadvantages of central inverters, string inverters, microinverters and power optimizers (which are not inverters but can be used with central or string inverters to increase energy production) and determine which DC to AC conversion technology would be best for the specific array. In addition, solar carports introduce new complexities into the design of solar arrays. Research into snow loading and wind loading for a solar carport would be very useful for determining whether a flat carport is possible on top of the parking garage and how much reinforcement is necessary for different tilt angles due to wind loading.

Further exploration into the possibility of community-shared solar should also be done. While community-shared solar (CSS) is innovative and has a high potential for making the benefits of solar energy accessible to more people, there is also little precedent and it is necessary to look further into how it could be executed at Smith. For instance, CSS participants could directly own their share of the array or a special purpose entity like an LLC could be created and participants could pay a monthly subscription. Either way, participants would receive net metering credits that they could apply to their electric bills. However, the income levels and tax appetite of Smith community members could be important factors in determining whether direct-ownership CSS or subscription-based CSS would be a better option for the Smith community. In addition, interest could need to be gauged before requesting bids from developers and participants would need to be recruited before the system was installed. A student could work on creating an educational and engagement campaign for the Smith community so that stakeholders understand the benefits of community-shared solar and have input into the final PV system design.

Appendices

Appendix A

Preliminary System Layouts

A.1 Ainsworth Gym System Layout

Table A.1: Preliminary design specifications of PV array on Ainsworth Gym

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	273	Portrait	0	-20	0.0
Section 2	125	Portrait	0	-20	0.0
Section 3	19	Portrait	35	70	0.0

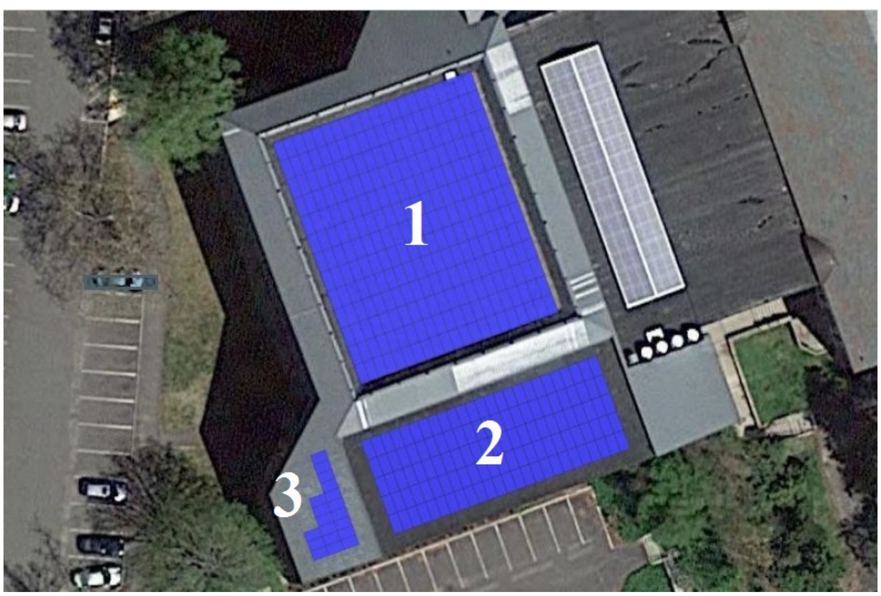


Figure A.1: PV system layout on Ainsworth Gym, with array section labeled.

A.2 Conway House System Layout

Since the modules in Section 1 are tilted only slightly east-facing, they were modeled as flat (tilt angle 0°) when calculating energy production.

Table A.2: Preliminary design specifications of PV array on Conway House

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	8	Landscape	10	-88	0.0
Section 2	11	Portrait	0	2	0.0
Section 3	41	Portrait	40	47	0.0
Section 4	6	Portrait	0	1	0.0

Figure A.2: PV system layout on Conway House, with array sections labeled.

A.3 Cutter-Ziskind System Layout

Table A.3: Preliminary design specifications of PV array on Cutter House and Ziskind House

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	204	Portrait	0	10.4	0.0
Section 2	129	Portrait	0	10.2	0.0

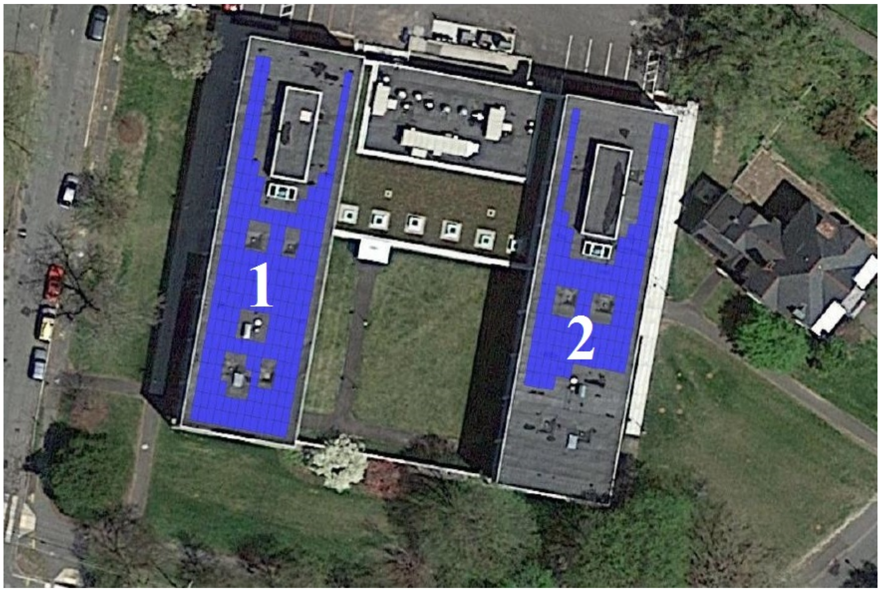


Figure A.3: PV system layout on Cutter House and Ziskind House, with array sections labeled.

A.4 Fort Hill System Layout

Table A.4: Preliminary design specifications of PV array on Fort Hill

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	4145	Landscape	10	0	0.46

Figure A.4: PV system layout on Fort Hill.

A.5 Parking Garage System Layout

Table A.5: Preliminary design specifications of PV array on the parking garage

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	507	Landscape	10	-17.9	0.49
Section 2	252	Landscape	10	-17.8	0.49

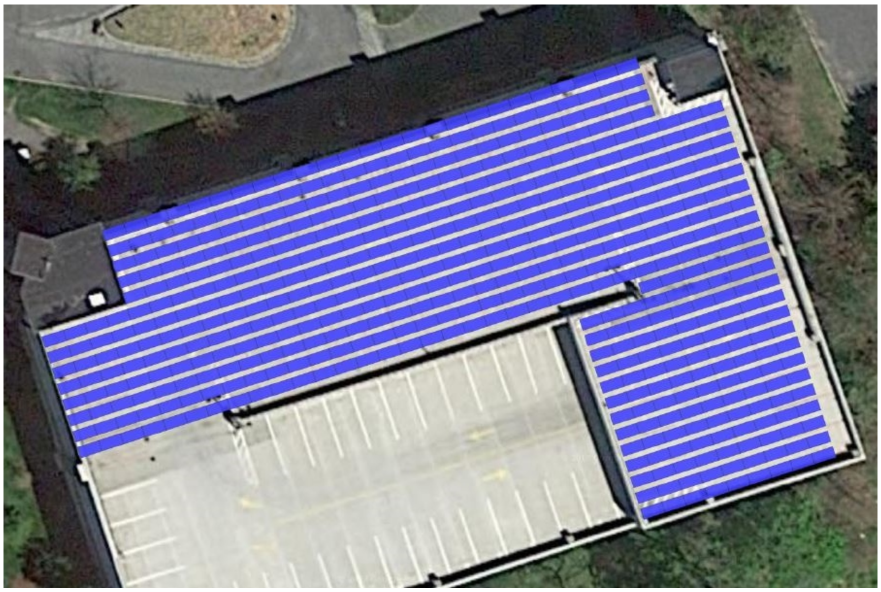


Figure A.5: PV system layout for Section 1 on the parking garage.

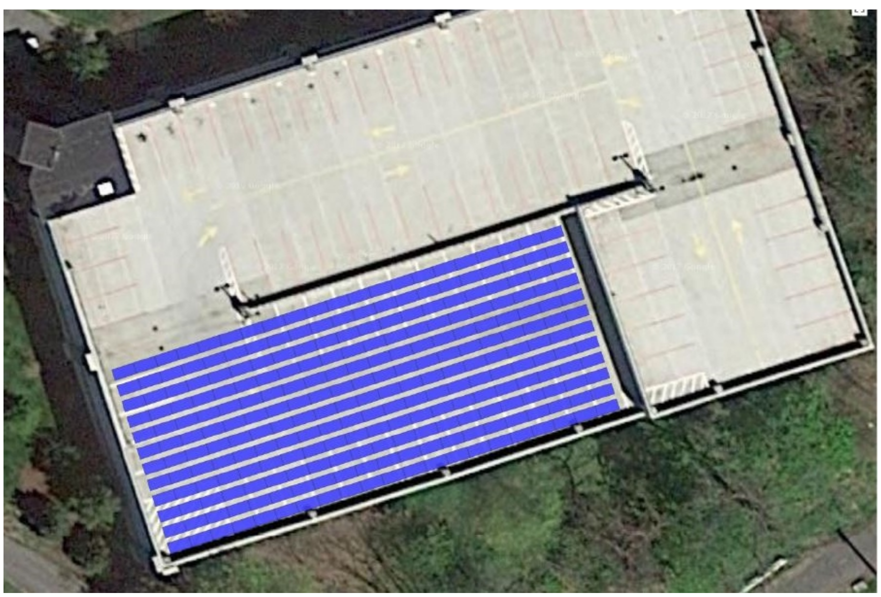


Figure A.6: PV system layout for Section 2 on the parking garage.

A.6 Tennis Court Parking Lots System Layout

Since the solar canopies at the tennis court parking lots would be covering individual rows of cars, inter-row shading is not an issue. Sections 1 and 2 were given a larger tilt angle closer to the optimal tilt angle of 37.74° (see Appendix D.7) since these rows faced south. Sections 3, 4, and 5 were given a tilt angle of 10° because they would be west-facing; a small tilt angle would still be desirable to avoid collecting debris and precipitation, but increasing the tilt angle does not increase the annual energy production like it would for a south-facing array.

Table A.6: Preliminary design specifications of PV array on the tennis court parking lots

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	57	Portrait	35	-15	0.0
Section 2	92	Portrait	35	-61	0.0
Section 3	56	Landscape	10	58	0.0
Section 4	294	Landscape	10	73.7	0.0
Section 5	147	Landscape	10	80.5	0.0

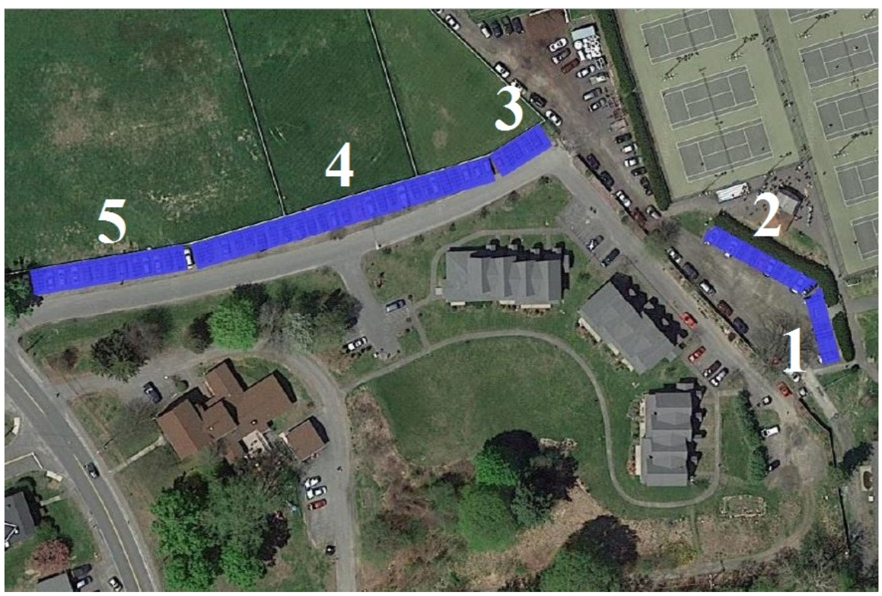


Figure A.7: PV system layout on the tennis court parking lots, with array sections labeled.

A.7 Wright Hall System Layout

Table A.7: Preliminary design specifications of PV array on Wright Hall

Section	Modules	Orientation	Tilt (°)	Surface Azimuth (°)	Spacing (m)
Section 1	80	Portrait	0	-15	0.0
Section 2	172	Portrait	0	-15	0.0
Section 3	64	Landscape	0	-15	0.0

Figure A.8: PV system layout for Section 1 on Wright Hall.

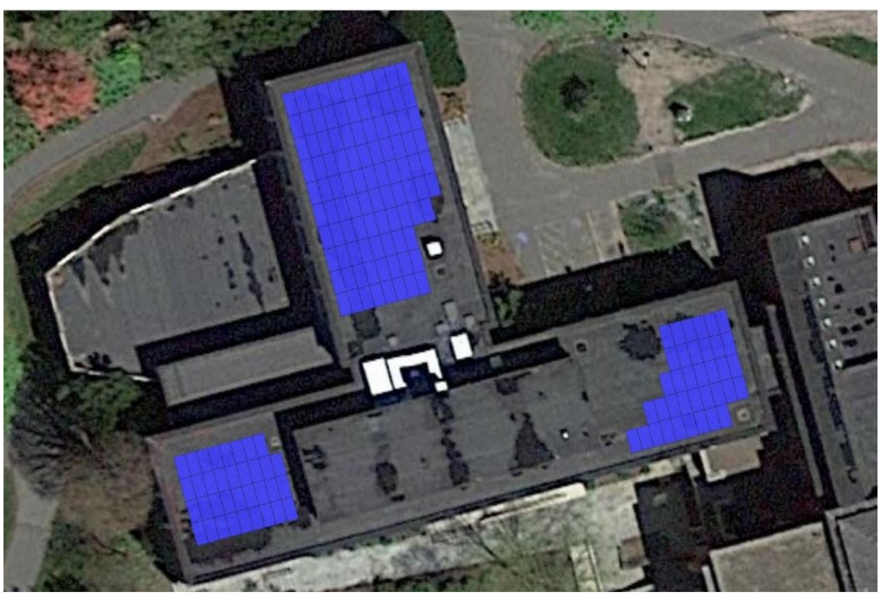


Figure A.9: PV system layout for Section 2 on Wright Hall.

Figure A.10: PV system layout for Section 3 on Wright Hall.

Appendix B

Addendum to Load Assessment

B.1 Electric Bills for the Parking Garage

The annual load for the parking garage, 55,727 kWh, was estimated as the total electricity usage at 50 West St Pole 11 from June 2015 to May 2016, tabulated in Table B.1. This information was taken from the electric bill issued on June 23, 2016.[124]

Table B.1: Electric usage history for 50 West St Pole 11 from June 2015 to May 2016

Month	Electricity Usage (kWh)
June 2015	3951
July 2015	3048
August 2015	2260
September 2015	2720
October 2015	3150
November 2015	3319
December 2015	4035
January 2016	4335
February 2016	7283
March 2016	7112
April 2016	6939
May 2016	7575

B.2 Electric Bills for the Tennis Court Parking Lots

The annual load for the tennis court parking lots, 12,877 kWh, was estimated as the total electricity usage of the field house and lights from February 2016 to January 2017, tabulated in Table B.2. This information was taken from the electric bill issued on February 6, 2017.[125]

Table B.2: Electric usage history for field house and lights from February 2016 to January 2017

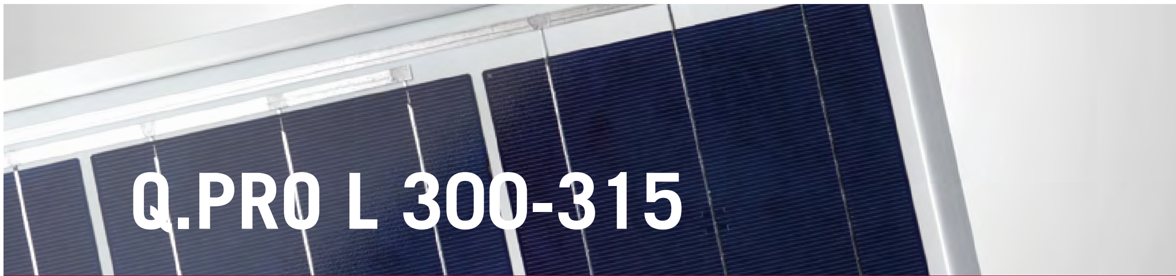
Month	Electricity Usage (kWh)
February 2016	990
March 2016	1091
April 2016	1020
May 2016	1301
June 2016	983
July 2016	764
August 2016	786
September 2016	1331
October 2016	1539
November 2016	1095
December 2016	1044
January 2017	913

Appendix C

Component Specifications

C.1 Module Datasheet

Datasheet courtesy of CivicSolar.[2]



Q.PRO L 300-315

POLYCRYSTALLINE SOLAR MODULE

The polycrystalline solar module Q.PRO L solar module with power classes up to 315 W is the strongest module of its type on the market globally. Powered by 72 Q CELLS solar cells and with a size of 2 m² Q.PRO L was specially designed for large solar power plants to reduce BOS costs. But there is even more to our polycrystalline modules. Only Q CELLS offers German engineering quality with our unique triple Yield Security.

YOUR EXCLUSIVE TRIPLE YIELD SECURITY

- Anti PID Technology (APT) reliably prevents power loss resulting from unwanted leakage currents (potential-induced degradation)[1].
- Hot-Spot Protect (HSP) prevents yield losses and reliably protects against module fire.
- Traceable Quality (Tra.Q™) is the 'Finger Print' of a solar cell. Tra.Q™ ensures continuous quality control throughout the entire production process from cells to modules while making Q CELLS solar modules forgery proof.

ONE MORE ADVANTAGE FOR YOU

- Reduced BOS costs: Optimised design to reduce costs per Wp.
- Improved energy yield: The actual output of all Q CELLS solar modules is up to 5 Wp higher than the nominal power thanks to positive sorting.
- Guaranteed performance: investment security do to 12-year product warranty and 25-year linear performance warranty[2].

EUPD RESEARCH TOP BRAND PV MODULES EUROPE 2014

Q CELLS YIELD SECURITY: ANTI PID TECHNOLOGY (APT), HOT-SPOT PROTECT (HSP), TRACEABLE QUALITY (TRA.Q™)

VDE Quality Tested: high reliability, low degradation, frequent product surveillance. ID. 40032587

Photon: Q CELLS Best polycrystalline solar module 2013, Q.PRO-G2 235, 151 modules tested

THE IDEAL SOLUTION FOR:

Ground-mounted solar power plants

[1] APT test conditions: Cells at -1000 V against grounded, with conductive metal foil covered module surface, 25 °C, 168 h

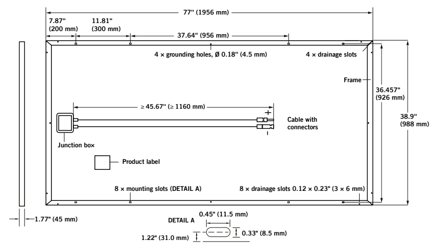
[2] See data sheet on rear for further information.

Engineered in **Germany**

Q CELLS

MECHANICAL SPECIFICATION

Format	77 in × 38.9 in × 1.77 in (including frame) (1956 mm × 988 mm × 45 mm)
Weight	59.52 lb (27.0 kg)
Front Cover	0.16 in (4.0 mm) thermally pre-stressed glass with anti-reflection technology
Back Cover	Composite film
Frame	Anodised aluminium
Cell	6 × 12 polycrystalline solar cells
Junction box	Protection class IP67, with bypass diodes
Cable	4 mm² Solar cable; (+) ≥ 45.67 in (1160 mm), (-) ≥ 45.67 in (1160 mm)
Connector	SOLARLOK PV4, IP68



ELECTRICAL CHARACTERISTICS

PERFORMANCE AT STANDARD TEST CONDITIONS (STC: 1000 W/m², 25 °C, AM 1.5 G SPECTRUM)[1]

NOMINAL POWER (+5 W/-0 W)		[W]	300	305	310	315
Average Power	P_{MPP}	[W]	302.5	307.5	312.5	317.5
Short Circuit Current	I_{SC}	[A]	8.93	8.97	9.01	9.06
Open Circuit Voltage	V_{OC}	[V]	45.27	45.56	45.84	46.13
Current at P_{MPP}	I_{MPP}	[A]	8.34	8.40	8.47	8.53
Voltage at P_{MPP}	V_{MPP}	[V]	36.27	36.59	36.91	37.23
Efficiency (Nominal Power)	η	[%]	≥15.5	≥15.8	≥16.0	≥16.3

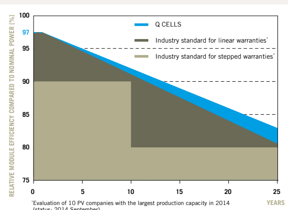
PERFORMANCE AT NORMAL OPERATING CELL TEMPERATURE (NOCT: 800 W/m², 45 ±3 °C. AM 1.5 G SPECTRUM)[2]

NOMINAL POWER (+5 W/-0 W)		[W]	300	305	310	315
Average Power	P_{MPP}	[W]	222.9	226.6	230.3	233.9
Short Circuit Current	I_{SC}	[A]	7.20	7.24	7.27	7.30
Open Circuit Voltage	V_{OC}	[V]	42.14	42.41	42.68	42.95
Current at P_{MPP}	I_{MPP}	[A]	6.53	6.58	6.64	6.69
Voltage at P_{MPP}	V_{MPP}	[V]	34.15	34.42	34.70	34.97

[1] Measurement tolerances STC: ±3 % (P_{mpp}); ±10 % (I_{sc}, V_{oc}, I_{mpp}, V_{mpp})

[2] Measurement tolerances NOCT: ±5 % (P_{mpp}); ±10 % (I_{sc}, V_{oc}, I_{mpp}, V_{mpp})

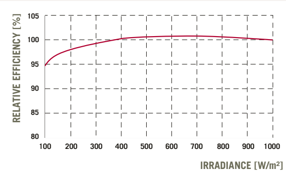
Q CELLS PERFORMANCE WARRANTY



At least 97 % of nominal power during first year. Thereafter max. 0.6 % degradation per year.
At least 92 % of nominal power after 10 years.
At least 83 % of nominal power after 25 years.

All data within measurement tolerances. Full warranties in accordance with the warranty terms of the Q CELLS sales organisation of your respective country.

PERFORMANCE AT LOW IRRADIANCE



The typical change in module efficiency at an irradiance of 200 W/m² in relation to 1000 W/m² (both at 25 °C and AM 1.5 G spectrum) is -2 % (relative).

TEMPERATURE COEFFICIENTS (AT 1000 W/M², 25 °C, AM 1.5 G SPECTRUM)

Temperature Coefficient of I_{SC}	α	[%/K]	+0.04	**Temperature Coefficient of V_{OC}**	β	[%/K]	−0.30
Temperature Coefficient of P_{MPP}	γ	[%/K]	−0.42	**NOCT**		[°F]	113 ± 5.4 (45 ± 3 °C)

PROPERTIES FOR SYSTEM DESIGN

Maximum System Voltage V_{SYS}	[V]	1000 (UL)	**Safety Class**	II
Maximum Series Fuse Rating	[A DC]	20	**Fire Rating**	C
Max Load (UL)[2]	[lbs/ft²]	75 (3600 Pa)	**Permitted module temperature on continuous duty**	-40 °F up to +185 °F (-40 °C up to +85 °C)
Load Rating (UL)[2]	[lbs/ft²]	33 (1600 Pa)	[2] see installation manual	

QUALIFICATIONS AND CERTIFICATES

VDE Quality Tested, IEC 61215 (Ed. 2); IEC 61730 (Ed. 1), Application class A
This data sheet complies with DIN EN 50380.

C US Certified UL 1703 (254141)

PACKAGING INFORMATION

Number of Modules per Pallet	22
Number of Pallets per 53' Container	28
Number of Pallets per 40' Container	22
Pallet Dimensions (L × W × H)	79.1 in × 43.1 in × 46.5 in (2010 × 1095 × 1180 mm)
Pallet Weight	1429 lb (648 kg)

NOTE: Installation instructions must be followed. See the installation and operating manual or contact our technical service department for further information on approved installation and use of this product.

Hanwha Q CELLS USA Corp.
8001 Irvine Center Drive, suite 1250, Irvine CA 92618, USA I **TEL** +1 848 748 59 96 I **FAX** +1 949 748 59 84 I **EMAIL** q-cells-usa@q-cells.com I **WEB** www.q-cells.us

Engineered in **Germany**

C.2 Inverter Datasheet

Datasheet courtesy of Wholesale Solar.[4]

HiQ Solar TrueString 480V Inverter
TS480-8k Specifications

Features

- Rugged 3-phase 480V plug & play system
- Small and light (hand holdable, 24 lb.)
- Non-isolated inverter for use with ungrounded DC systems
- Peak 98.6% efficiency, CEC efficiency of 98%
- 200-850V MPP voltage range for 600V and 1,000V systems
- 8 kW_{AC} full power MPP voltage range 425-850V
- Two DC string inputs with independent monitoring and MPPT management.
- Waterproof NEMA6, silent convection cooling
- Designed for high reliability, uses no electrolytic capacitors
- Wide temperature range, -40 to +65 °C
- Utility-Interactive; Listed to UL1741
- Compliant with NEC 690.11 arc detection

Note
Operates on 5-wire wye - neutral must be connected or damage may result

Applications

- Rooftop commercial, usable where other solutions just won't work - for example coastal, desert, high altitude locations
- Car ports, parking and shade structures; units may be mounted at any orientation, under modules, on racking without extra strengthening, clear of risk of liability from vandalism

HiQ Solar TS480-8k Specifications

DC Input (2 identical inputs)	
Maximum open circuit voltage per String, V_{OC}	1,000 V_{DC}
Full power MPPT range, per string	425-850 V_{DC}
PV start voltage	200 V_{DC}
DC allowable stacking ratio (total, 2 inputs combined)	Must not exceed 6.375 under any circumstances[1]
DC maximum input current, per DC input	10 A
DC maximum input short circuit current	30 A
DC maximum input source back feed current to input source	0 A
DC disconnect means	The DC connector has been evaluated and approved for use as the load-break disconnect required by the NEC[2]
AC Output	
AC maximum continuous total output power to +45 °C	8 kW_{AC} max
AC de-rate with temperature, +45 to +65 °C	-150 W/ °C
AC nominal output current, per phase	9.6 A
AC maximum continuous output current, per phase	9.6 A
AC maximum output over current protection	60 A
AC 3-phase system compatibility	480V Wye, 3 phases, neutral and ground
AC voltage range, phase to phase (min / nominal / max)	422 / 480 / 528 V (Limits adjustable, see below)
AC voltage range, phase to neutral (min / nominal / max)	244 / 277 / 305 V (Limits adjustable, see below)
AC output frequency range (min / nominal / max)	59.3 / 60 / 60.5 Hz (Limits adjustable, see below)
Power Factor	≥0.98

Note 1: Stacking: On the DC side of the inverter, each input limits at 5 kW and/or 10A, and the combined total AC output is limited to 8 kW. Higher DC STC string powers may be applied, the inverter will limit as described above. Total stacking for inverter must not exceed 6.375 under any circumstances

Note 2: NEC section 690.17, allowed by the exception of meeting requirements specified in 690.33

AC Output, continued			
AC lower frequency trip limit	Default	59.3 Hz	+/- 0.1 Hz
	Adjustment	57-59.3 Hz in 0.1 Hz increments	
	Clearing time default	0.16 s	+/- 2 cycles
	Clearing time adjustment	0.16-300	
AC upper frequency trip limit	Default	60.5 Hz	+/- 0.1 Hz
	Adjustment	60.5-62.0 Hz in 0.1 Hz increments	
	Clearing time default	0.16 s	+/- 2 cycles
	Clearing time adjustment	0.16-300 s	
AC lower voltage trip limit (Phase to Neutral)	Default	245 V	+/- 2 %
	Adjustment	220-245 V	
	Clearing time default	2 s	+/- 2 cycles
	Clearing time adjustment	1-20 s	
AC upper voltage trip limit (Phase to Neutral)	Default	305 V	+/- 2 %
	Adjustment	305-315 V	
	Clearing time default	1 s	+/- 2 cycles
	Clearing time adjustment	1-20 s	
AC reconnect delay	Default	5 minutes	+/- 1 s
	Adjustment	1 s -10 minutes	
AC synchronization in-rush current		0 A	
Maximum output fault current and duration		10A, <0.5ms	
AC minimum wire gauge for grid connection		14 AWG	
AC disconnect means		The AC connector has been evaluated and approved for use as the load-break disconnect required by the NEC[2]	
Other Specifications			
Peak efficiency		98.6 %	
CEC efficiency		98.0 %	
Dimensions		475 x 334 x 76 mm (18 3/4 x 13 1/8 x 3”)	
Weight		11 kg (24 lb.)	
Operating temperature range		-40 to +65 °C (-40 to 150 °F)	
Power consumption standby/ night		<4.5 W / <4.5W	
Cooling		Natural convection, no fan	
Communication		Powerline	
Environmental rating		Outdoor / rooftop, NEMA 6, IP67	
Certification		Listed to UL 1741 / IEEE 1547 (Utility Interactive) CSA C22.2 NO. 107.1, FCC Part 15, meets the requirements of NEC 690.11	
Included warranty		10 Years, optionally extendable	

Ordering Guide		
Item	**Part Number**	**Description**
TrueString System	TS480-8k	**TrueString 480V Inverter, 8kW, 3-phase.** Inverter with MC4-compatible connectors. MPPT per string, monitoring per string. Includes 10 year limited warranty. *Does not include Gateway. Does not include AC cable, must be ordered separately.*
	TS480-8k-AUX	**TrueString 480V TrueString Inverter, 8kW, 480V 3-phase, with Aux Connector.** Inverter with MC4-compatible connectors (1ea). MPPT per string, monitoring per string, RS485 communication and Aux connector. Includes 10 year limited warranty. *Does not include Gateway. Does not include AC cable, must be ordered separately.*
	TS480-8k-W25	**Option - TrueString System Warranty Extension to 25 years for 1 TrueString 480V.** Must be ordered at time of system purchase. Includes system Gateway(s).
TrueString AC Cables	CBL-480A-05	**TrueString 480V AC Cable, 5ft.** Includes TrueString 480V AC mating connector, other end unterminated.
	CBL-480A-15	**TrueString 480V AC Cable, 15ft.** Includes TrueString 480V AC mating connector, other end unterminated.
	CBL-480A-30	**TrueString 480V AC Cable, 30ft.** Includes TrueString 480V AC mating connector, other end unterminated.
	CBL-480A-50	**TrueString 480V AC Cable, 50ft.** Includes TrueString 480V AC mating connector, other end unterminated.

2030 Duane Avenue, Santa Clara, CA 95054
info@hiqsolar.com, www.hiqsolar.com

Appendix D

Transposition to the Plane of the Array

The equations used in this section are based on the model used by Duffie and Beckman (1980),[32] which was developed by Liu and Jordan (1963) and extended by Klein (1977).[110] [111]

D.1 Solar Geometry

At any moment in time, the position of the sun relative to a plane on the surface of the earth can be described in terms of several angles.

Declination, δ, is the angular position of the sun at solar noon with respect to the plane of the equator,

$$\delta = 23.45° \sin\left(2\pi \frac{284 + n}{365}\right) \tag{D.1}$$

where n is the day-of-the-year number.

Hour angle, ω, is the angular displacement of the sun east or west of the local meridian. The hour angle increases by 15°every hour due to the rotation of the earth. The sunrise/sunset hour angle, ω_s, is the hour angle when the sun is on the horizon (i.e. $\theta_z = 90°$),

$$\cos\omega_s = -\tan\varphi\tan\delta \tag{D.2}$$

where φ is the latitude and δ is the declination.

Zenith angle, θ_z, is the angle between the vertical and the line to the sun,

$$\cos\theta_z = \cos\varphi\cos\delta\cos\omega + \sin\varphi\sin\delta \tag{D.3}$$

where φ is the latitude, δ is the declination, and ω is the hour angle. It is also equal to the angle of incidence of beam radiation on a horizontal surface.

Angle of incidence, θ, is the angle between the beam radiation on a surface and the normal to the surface,

$$\cos\theta = \begin{aligned}[t] &\sin\delta\sin\varphi\cos\beta \\ &-\sin\delta\cos\varphi\sin\beta\cos\gamma \\ &+\cos\delta\cos\varphi\cos\beta\cos\omega \\ &+\cos\delta\sin\varphi\sin\beta\cos\gamma\cos\omega \\ &+\cos\delta\sin\beta\sin\gamma\sin\omega \end{aligned} \tag{D.4}$$

where φ is the latitude, β is the angle between the surface and the horizontal (aka the tilt angle), γ is the surface azimuth angle (where 0° is due south, -90° is due east, and +90° is due west), and ω is the hour angle. If the array is tilted towards the sun, θ decreases and $\cos\theta$ approaches 1 . If $\gamma = 0$, then the equation simplifies to

$$\cos\theta = \begin{cases} \cos(\varphi-\beta)\cos\delta\cos\omega + \sin(\varphi-\beta)\sin\delta, & \varphi > 0 \\ \cos(\varphi+\beta)\cos\delta\cos\omega + \sin(\varphi+\beta)\sin\delta, & \varphi < 0 \end{cases} \tag{D.5}$$

for a south-facing array in the northern hemisphere ($\varphi > 0$) or a north-facing array in the southern hemisphere ($\varphi < 0$).

D.2 Diffuse Fraction of Insolation

$$\frac{\overline{H_d}}{\overline{H}} = \begin{cases} 1.391 - 3.560\overline{K_T} + 4.189\overline{K_T}^2 - 2.137\overline{K_T}^3, & \omega_s \leq 81.4° \text{ and } 0.3 \leq \overline{K_T} \leq 0.8 \\ 1.311 - 3.002\overline{K_T} + 3.427\overline{K_T}^2 - 1.821\overline{K_T}^3, & \omega_s > 81.4° \text{ and } 0.3 \leq \overline{K_T} \leq 0.8 \end{cases} \tag{D.6}$$

where $\overline{H}$ is the monthly average daily insolation on a horizontal surface, $\overline{H_d}$ is the diffuse component of $\overline{H}$, $\overline{K_T}$ is the monthly average clearness index, and ω_s is the sunrise/sunset hour angle.

D.3 Direct Beam Tilt Factor

The direct beam tilt factor, R_b, is the ratio between the beam radiation on a tilted surface and the beam radiation on a horizontal surface,

$$R_b = \frac{G_{b,T}}{G_b} = \frac{\cos\theta}{\cos\theta_z} \tag{D.7}$$

where $G_{b,T}$ is the beam radiation on a tilted surface, G_b is the beam radiation on a horizontal surface, θ is the angle of incidence on a tilted surface, and θ_z is the angle of incidence on a horizontal surface. Equations D.3 and D.5 can be substituted into Equation D.7 to solve for R_b, assuming that the surface azimuth angle is 0.

However, the average direct beam tilt factor for a specific month, $\overline{R_b}$, is calculated using the following equation:

$$\overline{R_b} = \frac{\cos(\varphi-\beta)\cos\delta\sin\omega_s' + \frac{\pi}{180^\circ}\omega_s'\sin(\varphi-\beta)\sin\delta}{\cos\varphi\cos\delta\sin\omega_s + \frac{\pi}{180^\circ}\omega_s\sin\varphi\sin\delta}\ , \qquad \omega_s' = \min\begin{bmatrix}\arccos(-\tan\delta\tan\varphi)\\ \arccos(-\tan\delta\tan(\varphi-\beta))\end{bmatrix} \tag{D.8}$$

where φ is the latitude, β is the tilt angle, δ is the declination, ω_s is the sunrise/sunset hour angle, and ω_s' is a modified sunrise/sunset hour angle that accounts for the sun setting behind the array before it sets behind the horizon. Equation D.8 assumes that the surface azimuth angle is 0.

D.4 Measured Monthly Average Daily Insolation on a Horizontal Surface

The data in Table D.1 was measured by the NASA Atmospheric Science Data Center at a latitude of 42.3° and a longitude of 72.6°from July 1983 to June 2005.[113] This data was used for calculating annual insolation and annual energy production for all arrays.

Table D.1: Monthly average daily insolation, $\overline{H}$ $(kWh/m^2/day)$, at 42.3°N, 72.6°E

Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	*Average*
1.85	2.58	3.51	4.65	5.77	6.54	6.59	6.10	4.90	3.35	2.11	1.56	4.13

However, this data is actually for the incorrect location. The correct insolation for Northampton, MA (latitude 42.3°, longitude -72.6°) is shown in Table D.2. It is estimated that insolation was overestimated by about 10%, but possibly up to 20%. Future work would include repeating transposition calculations with the correct data and improving the estimates of annual energy production.

Table D.2: Monthly average daily insolation, $\overline{H}$ $(kWh/m^2/day)$, at 42.3°N, 72.6°W

Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	*Average*
1.77	2.67	3.62	4.38	5.12	5.57	5.62	5.01	4.07	2.87	1.83	1.50	3.67

D.5 Monthly Reflectivity Values

Monthly reflectivity values, shown in Table D.3, were estimated for Northampton, MA based on the combination of the man-made environment and seasonal changes to the natural landscape. These values were determined qualitatively by comparing to published reflectivity values for different surfaces, shown in Table D.4.

Table D.3: Estimated monthly ground reflectivity values, ρ_g, for Northampton, MA

Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
0.75	0.75	0.60	0.30	0.25	0.25	0.25	0.25	0.25	0.30	0.30	0.60

Table D.4: Reflectivity values for different surfaces, integrated over the solar spectrum and angle of incidence [5]

Surface	Average reflectivity
Snow	0.75
Water surfaces	0.07
Soils	0.14
Earth roads	0.04
Coniferous forest (winter)	0.07
Forests in autumn, plants	0.26
Weathered blacktop	0.10
Weathered concrete	0.22
Dead leaves	0.30
Dry grass	0.20
Green grass	0.26
Bituminous and gravel roof	0.13
Crushed rock surface	0.20
Building surfaces, dark	0.27
Building surfaces, light	0.60

D.6 Example Transposition Spreadsheet

A spreadsheet was used to calculate the annual energy production per square meter at any tilt angle. The spreadsheet utilized the equations from Appendices D.1 to D.3, the monthly average daily insolation data shown in Table D.1, and the reflectivity values shown in Table D.3.

The example spreadsheet below calculates the annual energy production per square meter at 37.74°, the optimal tilt angle in Northampton, MA for a single module. Table D.5 provides further information about the units and definitions of the symbols used in the spreadsheet.

Constants

G_{sc}	1367
ϕ	42.3
P_{mpp}	312.5
A_{module}	1.9325
η_{PV}	0.1617
η_{derate}	0.77
β (°)	37.74

Month	n	N	δ	ω_s	H_o	H	K_T	H_d/H	H_d	H_b	ω_s'	R_b	ρ_g	H_T	$\Sigma E_{in,T}$	$\Sigma E_{out,T}$
Jan.	16	31	-21.1	69.4	3.80	1.85	0.49	0.40	0.75	1.10	69.4	2.372	0.75	3.43	106.33	13.24
Feb.	45	28	-13.6	77.3	5.21	2.58	0.50	0.40	1.02	1.56	77.3	1.887	0.75	4.06	113.62	14.15
Mar.	75	31	-2.4	87.8	7.32	3.51	0.48	0.46	1.61	1.90	87.8	1.425	0.6	4.37	135.42	16.86
Apr.	105	30	9.4	98.7	9.44	4.65	0.49	0.45	2.07	2.58	90.8	1.102	0.3	4.84	145.26	18.09
May	136	31	19.0	108.3	11.01	5.77	0.52	0.42	2.40	3.37	91.6	0.912	0.25	5.37	166.54	20.74
June	166	30	23.3	113.1	11.63	6.54	0.56	0.38	2.50	4.04	92.0	0.839	0.25	5.80	173.99	21.66
July	197	31	21.4	110.8	11.30	6.59	0.58	0.36	2.40	4.19	91.8	0.872	0.25	5.97	185.17	23.06
Aug.	228	31	13.5	102.6	10.02	6.10	0.61	0.34	2.09	4.01	91.1	1.017	0.25	6.11	189.33	23.57
Sept.	258	30	2.2	92.0	8.08	4.90	0.61	0.34	1.69	3.21	90.2	1.283	0.25	5.76	172.77	21.51
Oct.	289	31	-10.0	80.8	5.84	3.35	0.57	0.32	1.09	2.26	80.8	1.712	0.3	4.95	153.54	19.12
Nov.	319	30	-19.1	71.6	4.14	2.11	0.51	0.38	0.80	1.31	71.6	2.224	0.3	3.69	110.68	13.78
Dec.	350	31	-23.4	66.8	3.37	1.56	0.46	0.43	0.67	0.89	66.8	2.572	0.6	2.99	92.66	11.54
Annual						4.13								4.78	1745.30	**217.32**
						Average								Average	Total	Total

Table D.5: Descriptions of symbols used in transposition spreadsheet

Symbol	Unit	Definition
G_{sc}	W/m^2	Solar constant
ϕ	°	Latitude
P_{mpp}	W	Maximum power of module at STC
A_{module}	m^2	Area of module
η_{PV}		Photovolatic efficiency
η_{derate}		Derate factor
β	°	Tilt angle
n		Day of the year
N		Number of days in month
δ	°	Declination
ω_s'	°	Modified sunrise/sunset hour angle
H_o	kWh/m^2	Monthly average daily extraterrestrial insolation
H	kWh/m^2	Monthly average daily insolation on horizontal surface
K_T		Clearness index
H_d	kWh/m^2	Monthly average daily diffuse insolation
H_b	kWh/m^2	Monthly average daily beam insolation
R_b		Monthly average direct beam tilt factor
ρ_g		Ground reflectivity
H_T	kWh/m^2	Monthly average daily insolation on tilted surface
$\sum E_{in}$	kWh/m^2	Monthly energy available (total is annual energy available)
$\sum E_{out}$	kWh/m^2	Monthly energy produced (total is annual energy produced)

D.7 Annual Energy Available and Annual Energy Production for Various Tilt Angles

Values of annual energy available per square meter and annual energy production per square meter are shown for various tilt angles in Table D.6. All values are for south-facing arrays at 42.3° latitude with Q PRO L 310 panels. Annual energy production per square meter was calculated by multiplying annual energy available (i.e. insolation) by the PV efficiency, 0.16, and the derate factor, 0.77. A tilt angle of 37.74° yielded the maximum annual energy production.

Table D.6: Annual energy available and annual energy production for various tilt angles

Tilt Angle (°)	Annual Energy Available ($kWh/m^2/yr$)	Annual Energy Production ($kWh/m^2/yr$)
0	1509	187.9
5	1565	194.9
10	1615	201.1
15	1657	206.3
20	1691	210.6
25	1717	213.8
30	1735	216.0
35	1744	217.2
37.74	1745	217.3
40	1744	217.2

D.8 Estimation of Array Size Needed to Replace Utility Purchases

This section estimates the array size that would be necessary to replace all electricity purchased from the utility with electricity generated by solar. The load was set equal to Smith's purchased electricity in FY 16, 8,000 MWh.[95] For simplicity, the array was assumed to be mounted on the horizontal and produce 187.9 kWh/m^2 per year. For the purpose of this calculation, it is assumed that all electricity produced would be consumed behind-the-meter or that excess generation would be valued as the full retail rate. In other words, each kWh of solar energy would replace a full kWh of energy purchased from the utility.

The total collecting area of the necessary array size was calculated using Equation D.9,

$$A = \frac{W}{E_u} \tag{D.9}$$

where A represents the collecting area of the array, W represents the load, and E_u represents the useful energy per unit area produced by the array. It was assumed that W was 8,000 MWh and E_u was 187.9 kWh/m^2, which yielded a collecting area of 42,576 m^2. Then, the total capacity of the array was then calculated using Equation D.10,

$$P = \frac{A}{A_{module}} P_{module} \tag{D.10}$$

where P was the total DC capacity, A was the total collecting area, A_{module} was the area of the module, and P_{module} was the maximum DC power of the module at STC. The area and power rating of the module, 1.93 m^2 and 312.5 W, respectively, were based on the specifications of the Q.PRO L 310 module. (See Appendix C.1.) Thus, it was estimated that an array with a capacity of 6.88 MW (about 7 MW) would be needed to produce 8,000 MWh per year.

Appendix E

Financial Impact Analysis

E.1 Historical and Projected Average Retail Rates in Massachusetts

Historical electricity retail rates in Massachusetts were obtained from aggregated sales and revenue data from 1990 to the present collected by the Energy Information Administration (EIA). This data, shown in Table E.1, was collected by Form EIA-861M, the Monthly Electric Power Industry Report, from a statistically chosen sample of electric utilities in the United States. These specific data are the year-to-date "total" prices, as in the total across all sectors (e.g. residential, commercial, industrial, transportation).[6]

Table E.1: Historical retail rates in Massachusetts [6]

Year	Total Retail Price (¢/kWh)	Year	Total Retail Price (¢/kWh)
1990	8.847	2004	10.767
1991	9.533	2005	12.181
1992	9.660	2006	15.449
1993	9.979	2007	15.163
1994	10.004	2008	16.234
1995	10.115	2009	15.447
1996	10.126	2010	14.258
1997	10.448	2011	14.113
1998	9.586	2012	13.788
1999	9.071	2013	14.512
2000	9.491	2014	15.355
2001	11.548	2015	16.902
2002	10.061	2016	16.472
2003	10.559		

Linear regression was performed on these data and the results, shown in Table E.2, were used

Table E.2: Linear regression table for total retail rate versus year

	Coefficients	Standard Error	T Statistic	P-value
Intercept	-596.6806656	63.25872371	-9.432385457	1.02887E-09
Year	0.303989346	0.03158175	9.625475015	6.8884E-10

to calculate projected retail rates for the future. In addition, the linear regression yielded an R square of 0.788. The line fit plot and the residuals are shown in Figures E.1 and E.2, respectively. The regression line on the line fit plot is extended to show the projection of future retail rates.

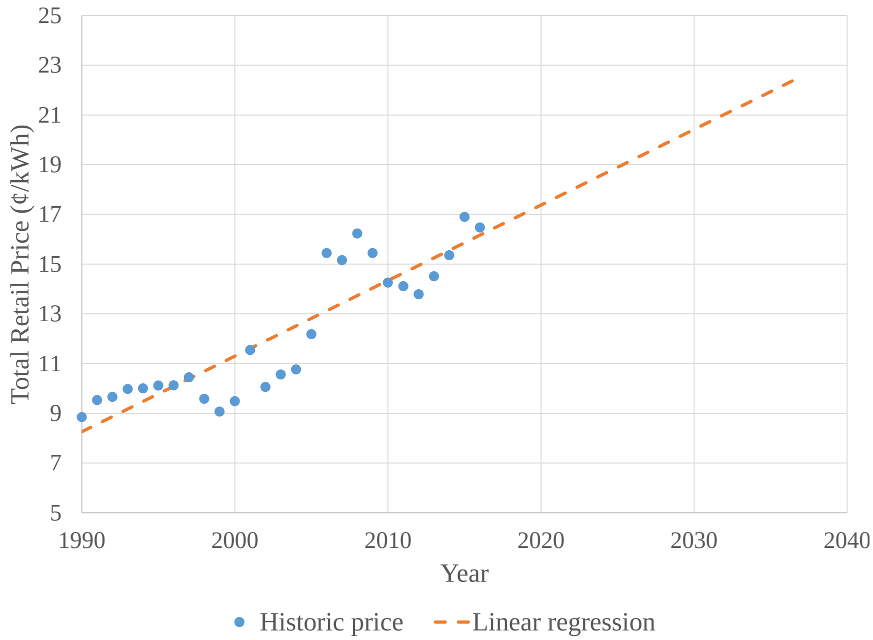


Figure E.1: Linear regression line fit plot for retail rates versus year

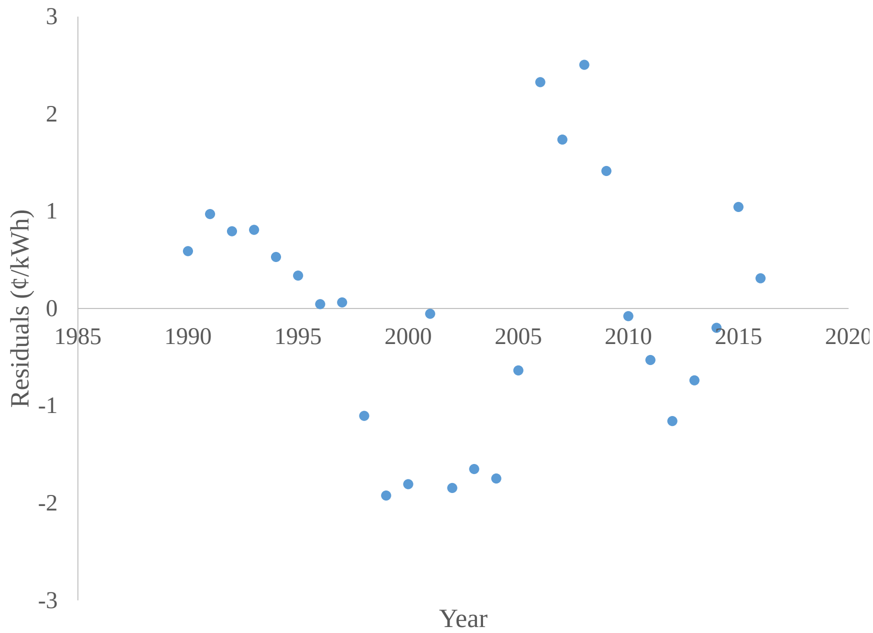


Figure E.2: Linear regression residuals plot for retail rates versus year

E.2 Life-Cycle Cost Formulas

The present worth of an annual expense is calculated according to Equation E.1:

$$pw = A \times \frac{\left(1 - (1 + I)^{-N}\right)}{I} \tag{E.1}$$

which is the formula for the uniform present worth (pw) of an annual sum (A) received or spent over a period of years (N) at a given discount rate (I).

Similarly, the annual worth of a present worth of an expense or revenue is calculating according to Equation E.2:

$$A = pw \times \frac{I}{\left(1 - (1 + I)^{-N}\right)} \tag{E.2}$$

which is the formula for the uniform annual worth (A) of a present expense or revenue over a period of years (N) at a given discount rate (I).

In all life-cycle assessments for this design, a discount rate of 6% was used.

E.3 Example of Lifetime Compensation Calculation

The table below demonstrates how the present worth of the total compensation over an array's lifetime was calculated. In this example, the total compensation for a net metering agreement on Fort Hill was calculated assuming a clearing price of competitive procurement of \$0.11/kWh. In the table, "PW" is an abbreviation for present worth.

Year	Energy (MWh/yr)	All-in rate ($/kWh)	Market NMC ($/kWh)	Compensation ($/kWh)	Total credits ($)	PW ($)
2018	1554.214843	0.121	0.100619014	0.121	188,060.00	188,060.00
2019	1554.214843	0.121	0.10244295	0.121	188,060.00	177,415.09
2020	1554.214843	0.121	0.104266886	0.121	188,060.00	167,372.73
2021	1554.214843	0.121	0.106090822	0.121	188,060.00	157,898.80
2022	1554.214843	0.121	0.107914758	0.121	188,060.00	148,961.13
2023	1554.214843	0.121	0.109738694	0.121	188,060.00	140,529.37
2024	1554.214843	0.121	0.11156263	0.121	188,060.00	132,574.88
2025	1554.214843	0.121	0.113386566	0.121	188,060.00	125,070.64
2026	1554.214843	0.121	0.115210502	0.121	188,060.00	117,991.17
2027	1554.214843	0.121	0.117034438	0.121	188,060.00	111,312.42
2028	1554.214843	0.121	0.118858374	0.121	188,060.00	105,011.72
2029	1554.214843	0.121	0.12068231	0.121	188,060.00	99,067.66
2030	1554.214843	0.121	0.122506246	0.122506246	190,401.03	94,623.48
2031	1554.214843	0.121	0.124330183	0.124330183	193,235.82	90,596.49
2032	1554.214843	0.121	0.126154119	0.126154119	196,070.60	86,722.22
2033	1554.214843	0.121	0.127978055	0.127978055	198,905.39	82,996.27
2034	1554.214843	0.121	0.129801991	0.129801991	201,740.18	79,414.27
2035	1554.214843	0.121	0.131625927	0.131625927	204,574.97	75,971.86
2036	1554.214843	0.121	0.133449863	0.133449863	207,409.76	72,664.72
2037	1554.214843	0.121	0.135273799	0.135273799	210,244.55	69,488.56
				Totals	3,859,302.24	2,323,743.47

E.4 Life-Cycle Assessment and Sensitivity Analysis

The results of the life-cycle assessment and the sensitivity analysis are shown below where each bolded and italicized row is the conservative estimate of the annual worth for the given system. The conservative estimates used a clearing price of $0.11 per kWh, which was the lower end of the predicted clearing prices, and the mean capital cost for the capacity range (see Table 3.7).

Constants	
Lifetime (yr)	20
O&M ($/kW$_{DC}$/yr)	19
Discount rate	0.06

Site	Capital ($/W$_{DC}$)	Rounded ($/W$_{DC}$)	Clearing ($/kWh)	DC capacity (kW$_{DC}$)	AC capacity (kW$_{AC}$)	Energy (MWh/yr)
Fort Hill CSS	3.267	3.3	0.11	1250	962.5	1554.214843
Fort Hill CSS	3.267	3.3	0.13	1250	962.5	1554.214843
Fort Hill CSS	***2.493***	***2.5***	***0.11***	***1250***	***962.5***	***1554.214843***
Fort Hill CSS	2.493	2.5	0.13	1250	962.5	1554.214843
Fort Hill CSS	1.719	1.7	0.11	1250	962.5	1554.214843
Fort Hill CSS	1.719	1.7	0.13	1250	962.5	1554.214843
Fort Hill NMA	3.267	3.3	0.11	1250	962.5	1554.214843
Fort Hill NMA	3.267	3.3	0.13	1250	962.5	1554.214843
Fort Hill NMA	2.493	2.5	0.11	1250	962.5	1554.214843
Fort Hill NMA	2.493	2.5	0.13	1250	962.5	1554.214843
Fort Hill NMA	1.719	1.7	0.11	1250	962.5	1554.214843
Fort Hill NMA	1.719	1.7	0.13	1250	962.5	1554.214843
Parking garage CSS	4.267	4.3	0.11	237.1875	182.634375	294.9122665
Parking garage CSS	4.267	4.3	0.13	237.1875	182.634375	294.9122665
Parking garage CSS	***3.493***	***3.5***	***0.11***	***237.1875***	***182.634375***	***294.9122665***
Parking garage CSS	3.493	3.5	0.13	237.1875	182.634375	294.9122665
Parking garage CSS	2.719	2.7	0.11	237.1875	182.634375	294.9122665
Parking garage CSS	2.719	2.7	0.13	237.1875	182.634375	294.9122665
Tennis court lots CSS	4.267	4.3	0.11	202.1875	155.684375	256.0586551
Tennis court lots CSS	4.267	4.3	0.13	202.1875	155.684375	256.0586551
Tennis court lots CSS	***3.493***	***3.5***	***0.11***	***202.1875***	***155.684375***	***256.0586551***
Tennis court lots CSS	3.493	3.5	0.13	202.1875	155.684375	256.0586551
Tennis court lots CSS	2.719	2.7	0.11	202.1875	155.684375	256.0586551
Tennis court lots CSS	2.719	2.7	0.13	202.1875	155.684375	256.0586551

Constants

Lifetime (yr)	20
O&M ($/kW$_{DC}$/yr)	19
Discount rate	0.06

Max capacity (kW$_{AC}$)	CBCR Factor
25	2
250	1.5
500	1.25
1000	1.1
2000	1

Site	Capital ($/W$_{DC}$)	Rounded ($/W$_{DC}$)	Clearing ($/kWh)	Compensation ($/kWh)	Total capital	Total O&M
Fort Hill CSS	3.267	3.3	0.11	0.171	($4,125,000.00)	($272,410.63)
Fort Hill CSS	3.267	3.3	0.13	0.193	($4,125,000.00)	($272,410.63)
Fort Hill CSS	***2.493***	***2.5***	***0.11***	***0.171***	***($3,125,000.00)***	***($272,410.63)***
Fort Hill CSS	2.493	2.5	0.13	0.193	($3,125,000.00)	($272,410.63)
Fort Hill CSS	1.719	1.7	0.11	0.171	($2,125,000.00)	($272,410.63)
Fort Hill CSS	1.719	1.7	0.13	0.193	($2,125,000.00)	($272,410.63)
Fort Hill NMA	3.267	3.3	0.11	0.121	($4,125,000.00)	($272,410.63)
Fort Hill NMA	3.267	3.3	0.13	0.143	($4,125,000.00)	($272,410.63)
Fort Hill NMA	2.493	2.5	0.11	0.121	($3,125,000.00)	($272,410.63)
Fort Hill NMA	2.493	2.5	0.13	0.143	($3,125,000.00)	($272,410.63)
Fort Hill NMA	1.719	1.7	0.11	0.121	($2,125,000.00)	($272,410.63)
Fort Hill NMA	1.719	1.7	0.13	0.143	($2,125,000.00)	($272,410.63)
Parking garage CSS	4.267	4.3	0.11	0.275	($1,019,906.25)	($51,689.92)
Parking garage CSS	4.267	4.3	0.13	0.305	($1,019,906.25)	($51,689.92)
Parking garage CSS	***3.493***	***3.5***	***0.11***	***0.275***	***($830,156.25)***	***($51,689.92)***
Parking garage CSS	3.493	3.5	0.13	0.305	($830,156.25)	($51,689.92)
Parking garage CSS	2.719	2.7	0.11	0.275	($640,406.25)	($51,689.92)
Parking garage CSS	2.719	2.7	0.13	0.305	($640,406.25)	($51,689.92)
Tennis court lots CSS	4.267	4.3	0.11	0.275	($869,406.25)	($44,062.42)
Tennis court lots CSS	4.267	4.3	0.13	0.305	($869,406.25)	($44,062.42)
Tennis court lots CSS	***3.493***	***3.5***	***0.11***	***0.275***	***($707,656.25)***	***($44,062.42)***
Tennis court lots CSS	3.493	3.5	0.13	0.305	($707,656.25)	($44,062.42)
Tennis court lots CSS	2.719	2.7	0.11	0.275	($545,906.25)	($44,062.42)
Tennis court lots CSS	2.719	2.7	0.13	0.305	($545,906.25)	($44,062.42)

Constants

Lifetime (yr)	20
O&M ($/kW$_{DC}$/yr)	19
Discount rate	0.06

Site	Capital ($/W$_{DC}$)	Rounded ($/W$_{DC}$)	Clearing ($/kWh)	Total revenue	Total present worth	Total annual worth
Fort Hill CSS	3.267	3.3	0.11	$3,048,369.43	($1,349,041.20)	($117,615.56)
Fort Hill CSS	3.267	3.3	0.13	$3,440,557.31	($956,853.32)	($83,422.83)
Fort Hill CSS	***2.493***	***2.5***	***0.11***	***$3,048,369.43***	***($349,041.20)***	***($30,431.00)***
Fort Hill CSS	2.493	2.5	0.13	$3,440,557.31	$43,146.68	$3,761.72
Fort Hill CSS	1.719	1.7	0.11	$3,048,369.43	$650,958.80	$56,753.55
Fort Hill CSS	1.719	1.7	0.13	$3,440,557.31	$1,043,146.68	$90,946.28
Fort Hill NMA	3.267	3.3	0.11	$2,323,743.47	($2,073,667.16)	($180,791.75)
Fort Hill NMA	3.267	3.3	0.13	$2,702,174.49	($1,695,236.14)	($147,798.41)
Fort Hill NMA	2.493	2.5	0.11	$2,323,743.47	($1,073,667.16)	($93,607.20)
Fort Hill NMA	2.493	2.5	0.13	$2,702,174.49	($695,236.14)	($60,613.85)
Fort Hill NMA	1.719	1.7	0.11	$2,323,743.47	($73,667.16)	($6,422.64)
Fort Hill NMA	1.719	1.7	0.13	$2,702,174.49	$304,763.86	$26,570.70
Parking garage CSS	4.267	4.3	0.11	$930,220.63	($141,375.54)	($12,325.76)
Parking garage CSS	4.267	4.3	0.13	$1,031,699.24	($39,896.93)	($3,478.40)
Parking garage CSS	***3.493***	***3.5***	***0.11***	***$930,220.63***	***$48,374.46***	***$4,217.51***
Parking garage CSS	3.493	3.5	0.13	$1,031,699.24	$149,853.07	$13,064.87
Parking garage CSS	2.719	2.7	0.11	$930,220.63	$238,124.46	$20,760.78
Parking garage CSS	2.719	2.7	0.13	$1,031,699.24	$339,603.07	$29,608.14
Tennis court lots CSS	4.267	4.3	0.11	$807,667.47	($105,801.20)	($9,224.23)
Tennis court lots CSS	4.267	4.3	0.13	$895,776.64	($17,692.03)	($1,542.47)
Tennis court lots CSS	***3.493***	***3.5***	***0.11***	***$807,667.47***	***$55,948.80***	***$4,877.87***
Tennis court lots CSS	3.493	3.5	0.13	$895,776.64	$144,057.97	$12,559.63
Tennis court lots CSS	2.719	2.7	0.11	$807,667.47	$217,698.80	$18,979.97
Tennis court lots CSS	2.719	2.7	0.13	$895,776.64	$305,807.97	$26,661.73

E.5 Annual Electric Bill of Average Massachusetts Resident

Based on the EIA Residential Energy Consumption Survey, the average Massachusetts household used about 6,980 kWh of electricity and spent about $1,131 on electricity in 2009.[126] [127] Thus the average price of electricity for residential customers was $0.16 per kWh.

Appendix F

Addendum to Detailed Design

F.1 Wire Sizing Spreadsheet

This spreadsheet was used to determine the necessary gauge of copper wire for the system voltage, voltage drop, safety factor, current, and wire length. The values shown in this spreadsheet are for the detailed design for the parking garage.

System Voltage	591 V
%Voltage Drop	2 %
Safety Factor	1.5

Wire Size

	20	18	16	14	12	10	8	6	4	2	1/O	2/O	3/O
Ohm/ft Actual	0.01015	.006385	.004016	2.5E-03	1.6E-03	1.0E-03	6.3E-04	4.0E-04	2.5E-04	1.6E-04	9.8E-05	7.8E-05	6.2E-05
Ohm/ft Design	0.01016	9.6E-03	6.0E-03	3.8E-03	2.4E-03	1.5E-03	9.4E-04	5.9E-04	3.7E-04	2.3E-04	1.5E-04	1.2E-04	9.3E-05
diam,mm	0.812	1.024	1.291	1.63	2.05	2.59	3.26	4.11	5.19	6.54	8.25	9.27	10.40

Wire Size

Current, A	20	18	16	14	12	10	8	6	4	2	1/O	2/O	3/O
1	1163	1234	1962	3121	4962	7889	12544	19944	31710	50416	80163	101155	127508
2	582	617	981	1560	2481	3944	6272	9972	15855	25208	40081	50578	63754
3	388	411	654	1040	1654	2630	4181	6648	10570	16805	26721	33718	42503
4	291	309	491	780	1241	1972	3136	4986	7928	12604	20041	25289	31877
5	233	247	392	624	992	1578	2509	3989	6342	10083	16033	20231	25502
6	194	206	327	520	827	1315	2091	3324	5285	8403	13360	16859	21251
7	166	176	280	446	709	1127	1792	2849	4530	7202	11452	14451	18215
8	145	154	245	390	620	986	1568	2493	3964	6302	10020	12644	15939
9	129	137	218	347	551	877	1394	2216	3523	5602	8907	11239	14168
10	116	123	196	312	496	789	1254	1994	3171	5042	8016	10116	12751
200	6	6	10	16	25	39	63	100	159	252	401	506	638
250	5	5	8	12	20	32	50	80	127	202	321	405	510
300	4	4	7	10	17	26	42	66	106	168	267	337	425
350	3	4	6	9	14	23	36	57	91	144	229	289	364
400	3	3	5	8	12	20	31	50	79	126	200	253	319
450	3	3	4	7	11	18	28	44	70	112	178	225	283
500	2	2	4	6	10	16	25	40	63	101	160	202	255

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