Williamstown Fire Station
Feasibility Assessment

Table of Contents

1 Executive Summary

EDM Architecture and Engineering (EDM) has retained Solar Design Associates (SDA) to investigate the solar potential of the proposed Williamstown Fire Station. Located on Main Street in Williamstown MA, the proposed site conditions, civil plans, and utility policies and their effect on potential solar photovoltaic production were examined.

SDA was provided with rooftop plans for the Fire station dated July 7th, 2022 in DWG format and a site civil plan dated July 28th, 2022 in DWG format from EDM. SDA created Helioscope and Energy Toolbase reports of the site on October 26th, 2022. As specified, three PV system proposals were created and presented herein. Helioscope takes the rooftop's access to sunlight into account and provides the estimated expected yearly production. Energy Toolbase provides a detailed ROI including the Net Present Value and the Payback Period.

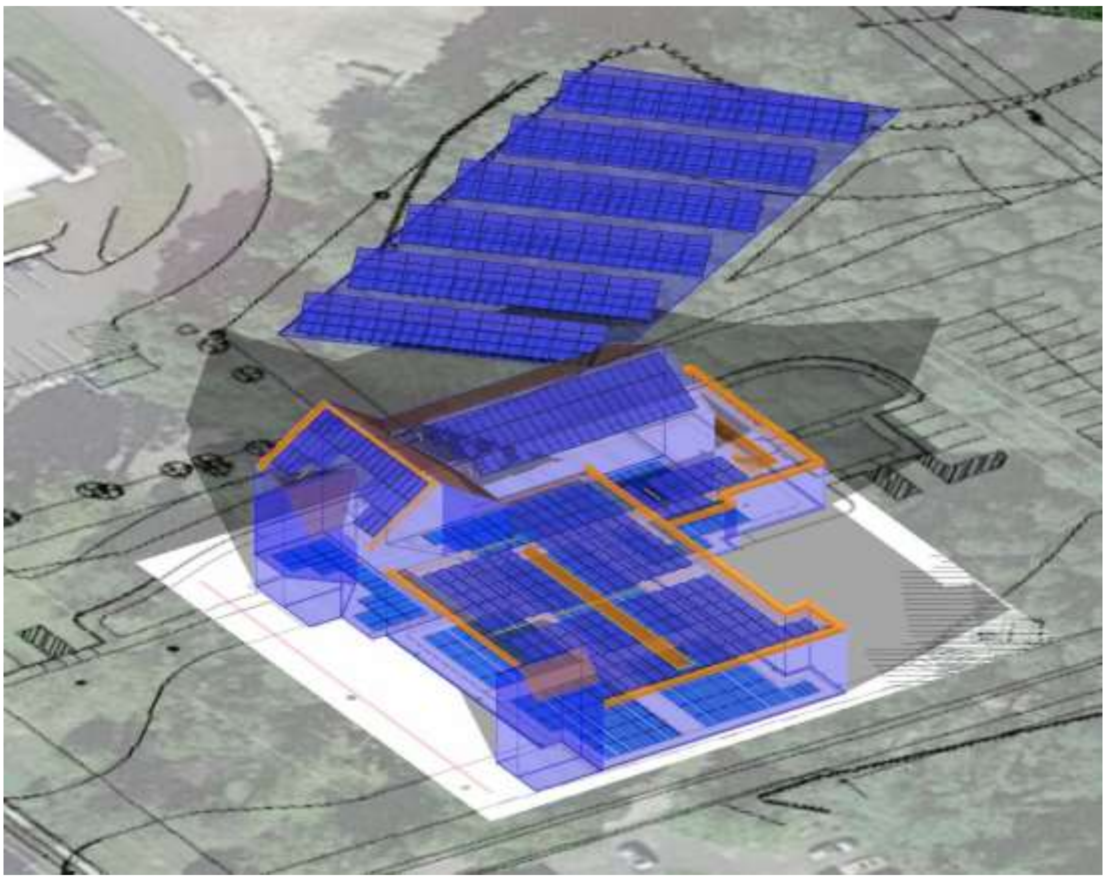

Figure 1: A Helioscope shot of the Williamstown Fire Station, PV Design by Solar Design Associates (October 2022).

1.1 Design Results and Conclusions

Assuming a solar ready roof space based off of the rooftop footprint proposed by SDA, multiple subarrays were investigated to determine roof coverage, walkway accessibility, and overall kWh production. SDA identified a racking tilt and system for each application that allowed for a high kWh/kWdc ratio while not compromising on wire management. The flat roof portions consists of the PanelClaw ClawFR 10˚ racking system with 11" row spacing. Eleven inch row to row spacing was chosen to maximize on roof coverage while still allowing for access to wiring beneath the modules. The system include ballasted racking which minimizes the use of mechanical attachments to the roof deck. The pitched roof sections of the building deploy flush mounted arrays at 32˚ and 23˚ tilts. These arrays use the IronRidge XR100 rails and the IronRidge FlashFoot2 weather-proof attachments for shingled roofs. The ground mount array will be fixed at a 25˚ tilt. This array will use the Terrasmart GLIDE agile racking system.

The PV system's interconnection strategy is covered in Section 6 with recommendations on what would be required given the array options, as well as what is required by the National Electric Code.

Given the assumptions laid out later in this report, SDA presents the following summary of the proposed system, presented in Table 1.

Sub-Array	Modules	Tilt	Azimuth	DC power (kW)	AC power (kW)	Estimated Production (kWh)
Upper Flat Roof	174/ 480W	10˚	223.6˚	83.52	120.0	89,608
Lower Flat Roof	21/ 480W	10˚	223.6˚	10.08		10,814
SW Flush Mount Roof	31/ 480W	32˚	223.6˚	14.88		15,965
SE Flush Mount Roof	66/ 480W	23˚	133.6˚	31.68		33,989
Ground Mount	288/ 480W	25˚	180.0˚	138.24	125.0	165,346
Total System	**580/ 480W**	**Varies**	**Varies**	**278.4**	**245.0**	**315,722**

Table 1: An overview of the power and production specifications of the subarrays

A detailed breakdown of the assumptions made for the above table can be found in section 7 and section 8 of this document.

2 Definitions

The following section defines terminology and industry vocabulary used throughout this document.

2.1 Rooftop Array Ballasting

The two main methods for securing PV modules to a roof surface are by the use of mechanical anchors or ballasting with concrete ballast blocks. Modules are typically attached to a racking structure situated above the roof surface, and the racking structure is secured to the roof via mechanical anchoring or held down in place via ballasting.

Ballasting a PV system on a flat roof is traditionally accomplished by placing hydraulically pressed concrete blocks inside ballast pans that are integrated into the racking system. The PV modules are mechanically fastened to the racking which is secured to the surface of the roof by the weight of the ballast. Ballasting an arrayis significantly less expensive than using mechanical attachments and requires only one work trade and no specialized labor to install.

2.2 Ground Array Racking

The two main methods for securing PV modules to the ground are by the use of posts driven into the ground or ballasting with concrete ballast blocks. Modules are typically attached to a racking structure supported above the ground via the posts.
The posts may be driven by either ground screws or placed in concrete piers. A ballasted system would likely consist of poured-in-place concrete blocks.

2.3 Behind-the-Meter PV System

A behind-the-meter system refers to a PV system which is interconnected on the customer's side of an existing utility meter, such that the PV system acts as a "negative load" offsetting existing "positive" building loads. The interconnection point for a behind-the-meter system can be anywhere on the customer side of the service's main meter. This type of interconnection requires upgrading the standard-issue utility meter to a bi-directional meter which is capable of measuring energy flow both into and out of the service point.

2.4 Edge Setback

The edge setback refers to the minimum distance a rooftop array must be kept away from the roof edge. Typical edge setbacks vary from 4 to 10 feet depending on local wind conditions, racking manufacturer guidelines, local permitting requirements, and maximum roof loading. Modules closer to the edge of the roof typically require more ballast to ensure the array remains in place. If there is not enough physical space under the racking to accommodate additional ballast blocks, or if the roof cannot support additional loading, mechanical attachments may be required. For this system, a 4' setback from the inside of the parapet wall was observed.

2.5 Far Shading

Far shading refers to shade that occurs as a result of distant objects that adversely impact the amount of solar radiation reaching the PV array. Nearby landscape features such as hills or a large stand of trees are considered to be far shading objects. A characteristic of far shading is that it affects the whole array at once. For example, if the sun were to go behind a mountain, the array would be quickly plunged into total shade.

2.6 Near Shading

Near shading refers to any object that affects the PV system in a highly localized manner. Obstructions on the roof such as vents, pipes, ladders, railings, and HVAC equipment are all examples of objects that can introduce near shading. Other objects such as adjacent trees, towers, chimney stacks, and tall buildings would also be considered near shading. Near shading is characterized by the manner in which it affects localized parts of the array, rather than affecting the entire array as would a far shading object. Near shading varies throughout the day and the seasons. For example, a vent pipe may only shade a single module at a particular time of day but may shade a different module at a different time of day. The shading impact from near shading objects is typically greater in the winter than the summer when the sun is lower in the sky.

2.7 Obstructions

Any feature added on or near the roof surface that either physically prevents potential module placement or casts shade on areas of potential module placement is an obstruction. This often includes objects such as roof drains, HVAC equipment, ductwork, plumbing vents, communication equipment, walkways, chimneys, and exhaust pipes. Obstructions not only physically take up roof space, but also cast shadows throughout the year thus reducing the available and viable area for PV modules.

2.8 Production Ratio

The production ratio refers to the ratio of projected or measured energy production of an array (in kilowatt-hours, kWh) to the array's dc nameplate (in kilowatts) and is expressed in units of kWh/kWdc. The production ratio can be thought of as a means to describe how much energy is produced by each module. This ratio is typically used for determining the efficiency of a particular solar array. With the amount of energy (kWh) produced by an array being nearly directly linked to the amount of revenue the system generates, the production ratio can help determine if it is economically advantageous to install more modules or if the system design will yield a desirable return on investment.

2.9 Shade Spray

Shade spray is a term used to define the cumulative shading impact of an obstruction, or any other object, over the course of the entire year. Solar Design Associates typically uses a shade spray defined by the following parameters:

Winter Solstice Shading: 10 am to 2 pm
Fall/Spring Equinox Shading: 8 am to 4 pm
Summer Solstice Shading: 8 am to 4 pm

A top-down view of a shade spray for an obstruction of arbitrary height is illustrated in **Figure 2**. Shade sprays are used to visualize the extent of shading from an obstruction and define the physical space impacted by an obstruction over the course of a year.

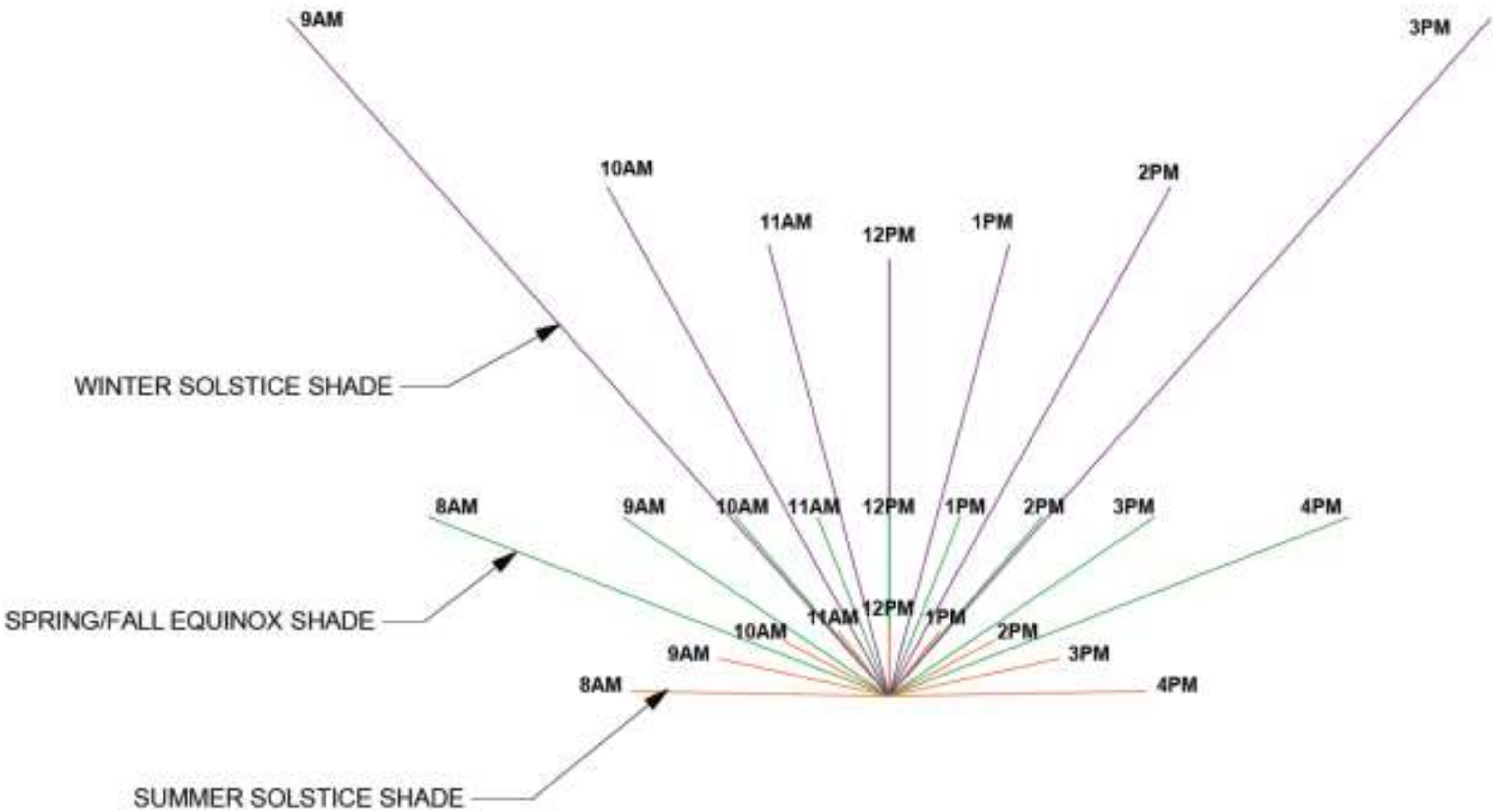

Figure 2: A depiction of a shade spray that is used to determine shading from an object as the sun moves throughout the sky relative to it. The shade causing point of the object would be located at the focal point of the diagram.

3 Basis of Design

Given the roof profile of the fire station along with its orientation, it was determined that the best racking configuration is a fixed-tilt ballasted system for the flat roof, a flush mount rail system for the tilted roofs, and a fixed tilt for the ground mounted system. These racking configurations can accept varying cell count modules as they are all standardized industry products. Necessary electrical equipment, such as optimizers and inverters, were also included in the feasibility analysis in order to gauge potential system sizes. This information further defines the energy production of the PV system as well as what will be required for interconnection into the building's electrical distribution system. All equipment that is part of this study have been chosen to best suit the needs and requirements of the project.

3.1 PV Modules

The namesakes for PV systems—as well as the most visible element—are the photovoltaic modules. Typically made from crystalline silicon, the semi-conducting solar cells create DC electricity when photons from sunlight strike the crystalline structure of the cell, releasing electrons from the structure which are then directed along bus bars and aggregated at junction boxes. Connecting many of these cells together allows for the transmission of this electricity, the scale of which can be enhanced and intensified through further connections with subsequent PV modules. While PV modules have been historically produced in various shapes and sizes, the market for distributed generation has settled on standards for varying cell count modules. The main difference between module sizes are their geometry and power output, with the larger cell count modules being both larger and more powerful.

Figure 3: The 156-cell module used in the PV system proposal, a QCells Q.PEAK DUO XL-G10.2 480W module

Both types of modules can be used anywhere but smaller modules are often chosen for residential rooftop applications while the larger modules are commonly chosen for commercial and ground mount applications. The larger physical size and higher wattage of these modules is beneficial for ground mount systems because fewer modules are required to achieve a certain amount of kWdc capacity, as compared to the same system constructed using the smaller modules. In this way, using the larger modules can greatly aid the speed of installation and reduce construction costs. smaller modules are typically more favorable on rooftops due to their smaller physical size. By building an array out of a smaller sub-unit, designers are capable of placing modules into tighter spaces between/around roof obstructions and are able to more closely follow complex roof geometry.

The 156 half-cell module chosen for this analysis is the Hanwha QCells Q.PEAK DUO XL-G10.2 480 module. It is a 480 Watt PV module that employs high-efficiency monocrystalline cells with a module efficiency of 20.7%. QCells is a Tier 1 manufacturer and includes a 25-year linear performance warranty and a 12-year product warranty. The modules are wind and snow load tested and approved for conditions in the northeast.

3.2 Inverters

Inverters are designed to convert DC electricity generated by the PV modules to AC electricity that is compatible with the building's electrical infrastructure. The rooftop arrays are designed to use a three-phase SolarEdge inverter with a 277/480Vac output voltage. The SolarEdge inverter pairs with DC optimizers distributed throughout the array to help mitigate conditions of localized shading, module soiling, and slight mis-matches between module electrical characteristics. DC-DC optimizers are mounted on the rear frame of the PV modules and provide for Rapid System Shutdown at the module level; a requirement of the 2020 National Electric Code (NEC) under section 690.12. The optimizer chosen for compatibility with these options is the SolarEdge P1101. This optimizer allows you to connect two modules to it in series and carries a UL3741 certification which satisfies NEC 2020 rapid shutdown requirements.

SolarEdge inverters offer a range of capabilities, including module-level monitoring, internet connectivity, and integrated arc fault protection as required by NEC 2017 690.11. Additionally, there is an integrated data monitoring system that is used to facilitate performance analysis, fault detection, and troubleshooting of the PV system. The integrated data monitoring suite is available via a web portal specifically designated to the building's PV system. SolarEdge inverters also come standard with a twelve-year warranty while the associated DC-DC optimizers come with a 25 year warranty. Inverter warranties extensions can be purchased for a period of up to 25 years. Figures 4 and 5 show images of the SolarEdge inverters as well as the DC-DC optimizers to be mounted to the module frames.

Figure 4: SolarEdge SE120KUS inverter, proposed for the rooftop system.

Figure 5: SolarEdge DC-DC optimizer. The optimizer is mounted directly to the module frame.

An SMA inverter was chosen for ground mount system in order to take advantage of 1500Vdc string voltages. Rooftop voltages are limited to 1000Vdc by the section 690.7 of the 2020 NEC. 1500Vdc allows for more efficient physical wiring of an array as well as less voltage drop losses for the system. Ground mount systems do not require the module level power electronics that are required for rooftop systems as 690.12 rapid shutdown does not apply to systems that are not located on a building. The SMA inverter will output three-phase 480Vac. A separate integrated data monitoring system is used to facilitate performance analysis, fault detection, and troubleshooting of the PV system. SMA offers a standard 5 year warranty, with optional extensions ranging between 10 to 25 years. Figure 6 shows an image of the SMA inverter.

Figure 6: SMA Sunny Highpower PEAK3 inverter, proposed for ground mount system.

3.3 Ballasted Fixed Tilt Racking System

Ballasted PV systems typically use racking structures to secure modules in place in continuous rows with a fixed tilt. The racking structure is then secured in place on the roof through the use of concrete ballast blocks. This system utilizes the weight of the racking and concrete blocks to keep the PV system secure during adverse weather conditions. SDA expects that the max distributed load for a ballasted system such as this not to exceed 8 lb/ft^2.

If additional means of securement are required beyond the capabilities of ballasting, mechanical attachments can be used. Generally speaking, the likelihood of attachments being required increases proportionally with the height of the building and inversely with the size of the array. At this time, SDA does not expect for attachments to be required, but a submittal of the design to the racking manufacturer would be required to confirm this.

Primary benefits of a ballasted racking system include its ease of installation and ease of removal for roof repairs. Ballasted arrays usually require no penetrations of the existing roof surface. Despite these advantages, this type of system cannot be used on all roofs due to the main mechanism of securement being the application of concrete ballast blocks. Prior to a candidate roof having a ballasted PV system installed, the ability of the roof to support the significant additional dead loading must first be confirmed by a licensed structural engineer. As the slope of the roof increases, the likelihood of the system requiring mechanical attachments increases as well. Most ballasted racking systems on the market can be installed on a roof with a slope as high as 7°. For the current assumed basis of design, the roof slope is adequate for the ballasted racking.

For this feasibility analysis, the PanelClaw clawFR 10° ballasted racking system was chosen based on its durability, versatility, reliability, and high module density. A single-tilt racking system was selected entirely due to it best suiting the orientation and geometry of the building’s roof. This particular racking solution is available with three row to row spacing options: 11”, 14”, or 17”. The row to row spacing is the closest measured distance between two adjacent module rows. The 11” repeat spacing option is explored in the designs that follow due to the high module density it offers. With this repeat spacing, more modules can fit within a given area.

Figure 8: An example of a PanelClaw clawFR roof mounted ballasted PV system.

3.4 IronRidge Flush Mount System

Flush mount PV systems typically use rails and attachments to secure modules in place in continuous rows. SDA assumes the tilt roof systems utilize shingles, which allows the use of the IronRidge FlashFoot2 attachment. This consists of a flashing, a custom-design lag bolt, and a twist on rail attachment cap.

The FlashFoot2 is installed by having the roof shingles overlap the flashing and then using a silicon seal or equivalent method to water proof the overlap. Then, the lag bolt secures the flashing in place and the rail attachment cap is twisted over the lag bolt. The elevated platform under the lug and a stack of rugged components are able to lift the seal an inch and divert water away. Additionally, the cap fully-encapsulates the seal. The multiple methods of water proofing allowed the FlashFoot2 to be the first solar attachment to pass the TAS-100 Wind-Driven Rain Test. Lastly, the rails are attached to the cap.

This particular attachment solution uniquely aligns the rail and lag bolt to create a stronger concentric loading design. With this design, the row to row spacing can be 1”, which allows for more modules fitting within a given area.

Figure 8: An example of a IronRidge FlashFoot2.

3.5 Fixed Tilt Ground Mount Racking System

PV systems typically use racking structures to secure modules in place in continuous rows with a fixed tilt. The racking structure is then secured in place through the use of driven posts or concrete ballast blocks. For this feasibility analysis, the TerraSmart GLIDE Agile racking system was chosen based on its durability, versatility, and reliability. This particular racking solution utilizes ground screws and is designed to work in a multitude of soil conditions. SDA estimates that each row of 4x12 modules will require eight ground screws to be properly supported.

SDA has chosen a array tilt of 25° in man attempt to balance row-to-row shading and PV production. This can be further refined as required as the project progresses. SDA determined a row-to-row spacing defined as the closest measured distance between two adjacent module rows of 16' based on the local winter solstice shading between the hours of 10am and 2pm.

Figure 5: An example of a screw driven ground mounted PV system.

4 Proposed Conditions

4.1 Proposed Roof Conditions

For the proposed rooftop layout shown, there is no equipment and minimal obstructions on the investigated roof surfaces. This will allow for more uniform array layouts across the roof sections. The only instance of physical obstruction to the PV are the roof drains on the lower flat roof.

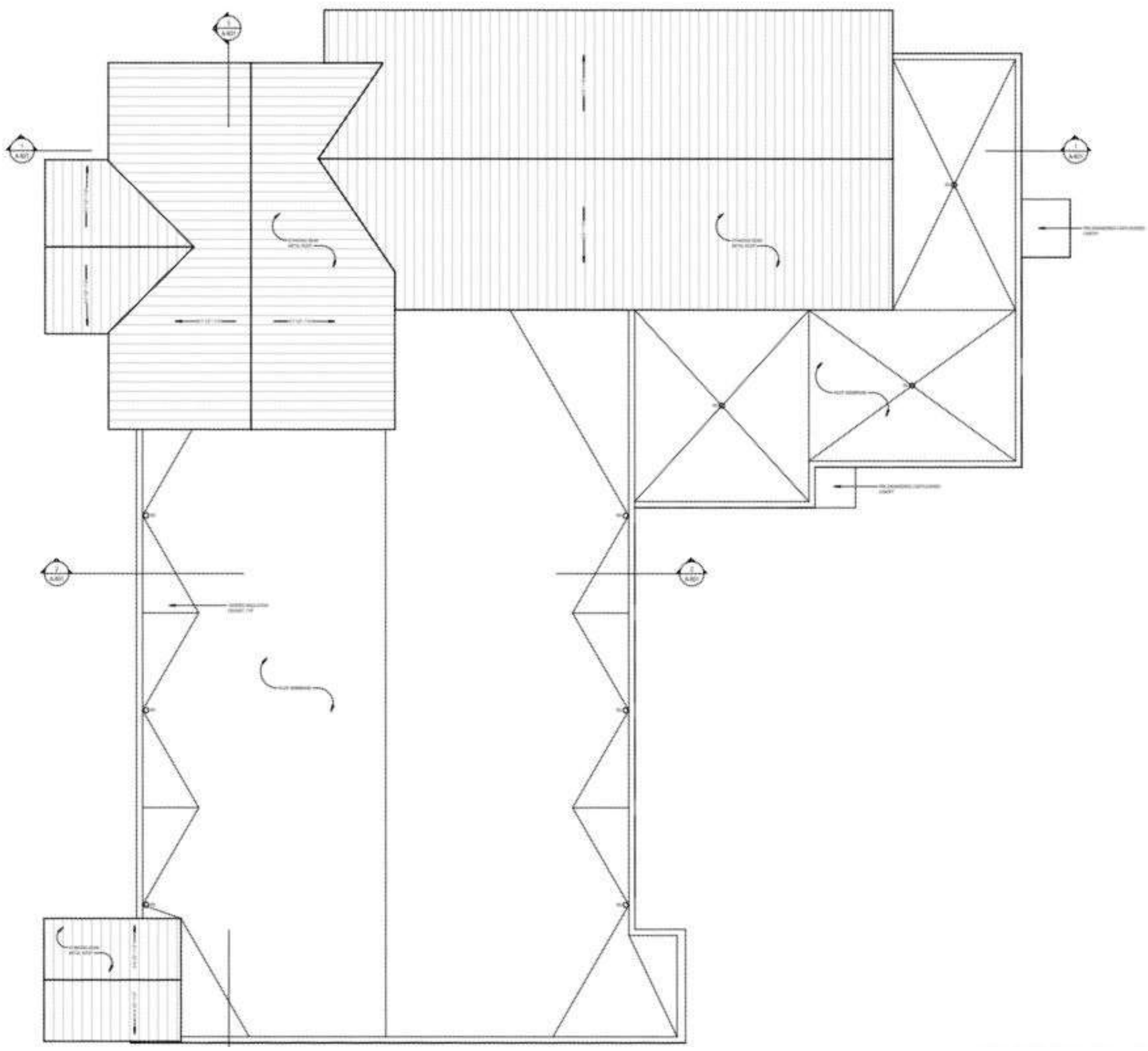

Figure 6: The proposed roof plan provided by EDM.

4.2 Proposed Civil Conditions

For the proposed site plan shown, the proposed ground mount solar system would occupy the east of the site. It would be positioned between the parking lane, the 15’ side yard setback to the east, the 50’ wetland buffer to the north, and the storm water rain garden. The site plan indicates a “new tree line” up to this 15’ setback on the east. SDA would recommend the fire station cut as much of the tree line on the east as feasible in order to minimize shading on the array. The tree line along the wetland buffer zone can remain, as trees to the north of the panel will not impact system production.

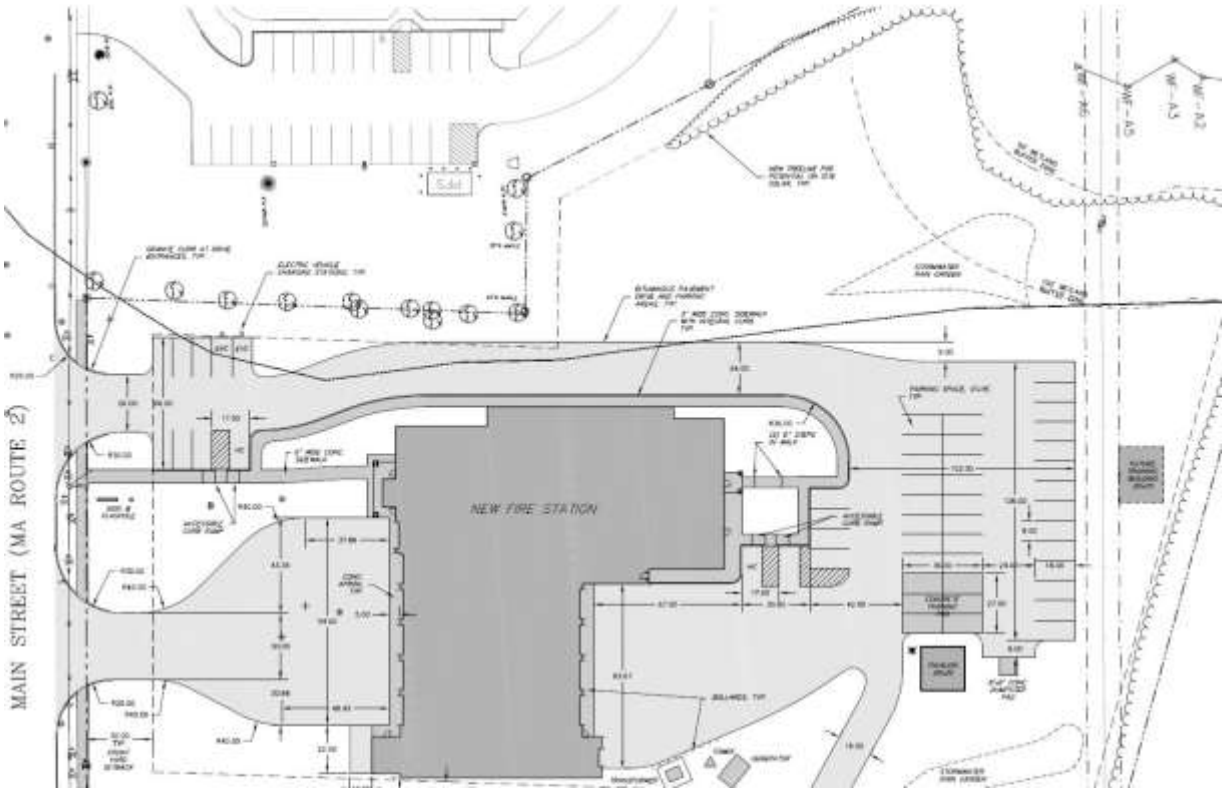

Figure 7: The site plan provided by EDM.

5 System Design Proposals

Influenced by the knowledge gathered from Section 4's proposed plans, this report focuses on the roof and ground areas available for the installation of a PV system. Power production of each PV system was estimated by using Folsom Lab's Helioscope calculator in conjunction with Energy Tool Base's financial modeling software.

The following are the assumptions and guidelines used to develop this analysis:

- A target kWh goal to meet estimated site consumption of 300,000 kWhr/year, with a PV production buffer above that to ensure the net zero goals are met.
- A roof edge setback of 4 feet was utilized as is allowed for a building of these dimensions.
- A 15' side setback from the property line was observed. No fencing will be used for the ground mount array.
- All rooftop features were treated as obstacles and the PV array will not contact any existing equipment. All rooftop features and equipment were modeled as obstructions with an associated height to account for any localized areas of shadow that may occur.
- The system was modeled using string inverter typology. The specific modeled inverter type for this study are the SolarEdge SE120KUS and the SMA SHP 125-US-21 inverters.
- National Solar Radiation Database (NSRDB) gridded insolation data for the location (42.70°N, 73.17°W) was used to estimate production.

5.1 Option 1 – (278.40 kWdc, 245.00 kWac)

Module Specifications: 580qty/ 480W QCells Q.PEAK DUO XL-G10.2 480
Racking: PanelClaw clawFR 10 Degree 11" Spacing
IronRidge XR1000 Rails - Flush Mount
Terrasmart GLIDE Agile, 25°, 16' Spacing
Inverters: 1qty / 120.0kW SolarEdge SE120KUS
1qty / 125.0kW SMA SHP 125-US-21

Option 1 consists of thirteen subarrays; 4 on the upper flat roof, 1 on the lower flat roof, 1 on the southwest flush mount roof, 1 on the southeast flush mount roof, and 6 on the ground mount.

The array totals 278.40 kWdc with 580qty QCells Q.PEAK DUO XL-G10.2 480W PV modules. The flat roof arrays are mounted on PanelClaw's clawFR 10 Degree flat roof ballasted system and face 223.6°. The southwest flush mount array is mounted on IronRidge XR1000 rails at a tilt of 32° and face 223.6°. The southeast flush mount array is mounted in IronRidge XR1000 rails at a tilt of 23° and face 133.6°. The ground mount arrays are mounted on Terrsmart's GLIDE Agile 25 degree screw driven ground mount system and faces 180°.

Collectively, the inverters total to 245.0 kWac with 1qty SolarEdge SE120KUS inverters for rooftop arrays and SMA SHP 125-US-21 125.0kW inverter for the ground mount system. Also incorporated into the system to accommodate for module level shutdown are 150qty P1101 SolarEdge optimizers on the rooftop arrays. The final location for the inverters has yet to be determined, but SDA recommends locating the rooftop inverter inside the main electrical room and locating the ground mount inverter in the field on the racking structure itself.

Using Folsom Lab's solar production calculator Helioscope, the system is estimated to annually produce 183,005 kWh per year. The proposed layout can be seen in **Figure 8** on the next page.

PV Array	Azimuth	Modules	DC Power	AC Power	Annual Energy	Production Ratio (kWh/kWdc)
Rooftop	Varies	292/ 480W	140.16 kW	120.00 kW	150,376 kWh	1,072.9
Ground Mount	180°	288/ 480W	138.24 kW	125.00 kW	165,346 kWh	1,196.1
TOTAL	**Varies**	**580 /480W**	**278.40 kW**	**245.00 kW**	**315,722 kWh**	**1,134.1**

Table 2: Production Table for Option 1.

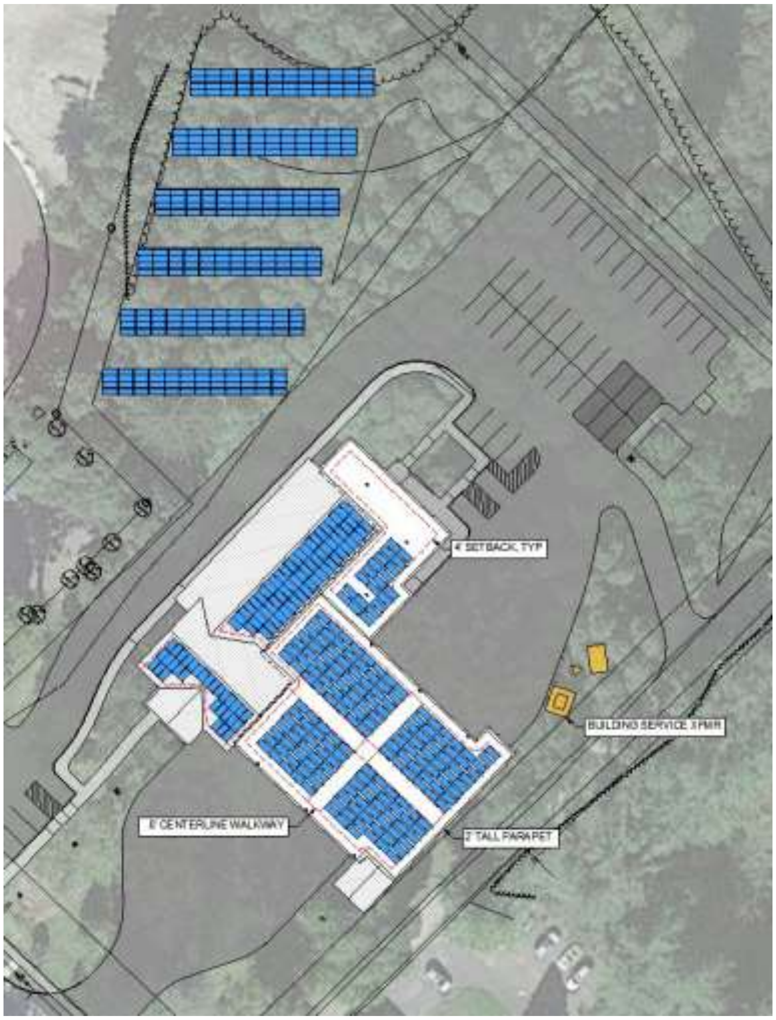

Figure 8: Option 1 proposed layout (278.4 kWdc; 245.0 kWac).

6 Electrical Interconnection

The method of electrical interconnection determines how the electricity generated by the PV system will reach building power circuits and ultimately, the grid. There are multiple methods to take care of this: the system can be a stand-alone system with its own inverter and service; the system can interconnect on the secondary side of the transformer; or the system can interconnect to the building's main distribution switchgear and have a designated circuit breaker. When designing how a PV system is to be integrated with a building that has yet to be designed or constructed, connecting to the main distribution switchgear—if room allows—is the desired method.

This site will be have one point of interconnection; Ideally the PV system will connect directly to the main switchboard in the main electrical room of the building. Shown below are three options of worked examples for determining the main breaker and bus size of the main switchboard. If the system size or equipment is changed, the minimum bus size should be determined as shown in the 120% equation below.

Total PV Current = 144.3 A (SE120KUS) + 151.0 A (SMA PEAK3 125kW) = 295.3A
PV Breaker Size 400A – Must be at least 295.3*1.25 = 369.125A

Coordinate Busbar Rating to Comply with NEC 705.12(B)(3)(2)
Located PV Interconnection Breaker at Opposite end of Bus from Main Supply

Main Breaker + 125%*PV Current ≤ 120% Busbar Rating

Given a Main Breaker of 1600A on a 1600A bus:
1600 + 125%*295.3 ≤ 120% *1600
1969 ≥ 1920, Not Code Compliant

Given a Main Breaker derated to 1500A on a 1600A bus:
1500 + 125%*295.3 ≤ 120% * 1600
1869 ≤ 1920, Code Compliance Confirmed

Given a Main Breaker of 2000A on a 2000A bus:
2000 + 125%*295.3 ≤ 120% *2000
2369 ≤ 2400, Code Compliance Confirmed

The above equipment and interconnection calculations are all based on the assumption that the system is 277/480Vac. However, if the system is 120/208Vac than either a step-down transformer could be used before interconnection, or 208V inverters could be used.

6.1 Equipment Requirements

The ideal location for PV inverters is in an electrical room adjacent to the main distribution switchgear and the point of interconnection, however nearly all inverters carry a NEMA 3R rating and are capable of being mounted outdoors in a strategic location (at a serviceable location and out of direct sunlight).

For the site, a dedicated panelboard is required to combine the output of the inverters. The panelboard will utilize a single set of conductors leaving the combiner traveling to the point of interconnection. Additional required equipment include an externally mounted AC disconnect (required by the utility) and an appropriately sized meter socket with its associated production meter.

An example of inverters with a PV panel and AC disconnect mounted to the side of a building can be seen below in Figure 8. The production meter for this system is not depicted.

Figure 9: An example installation of PV inverters with a PV combining panelboard and AC disconnect switch.

To size the interconnecting circuit breaker to a main distribution panel or switchgear, the combined output amperage of the inverters is multiplied by 1.25 to determine the required overcurrent protection device (OCPD). A table of their inverter output current and subsequent required breakers and interconnection breaker can be seen in **Table 5** below.

Inverter Model	Output Current (A)	Required Circuit Breaker (A)
SolarEdge SE120KUS	144.3A	200A
SMA PEAK3 125-US	151.0A	200A
Interconnection Total: 245.0 kWac	295.3A	400A

Table 3: Inverter currents leading to the required size of the interconnection breaker.

Referencing the above table, a dedicated 400A PV circuit breaker on the end of the buildings main switchboard be required for interconnection of the PV system. The system will have a utility required exterior mounted AC disconnect. Alternative methods of interconnection will need to comply with applicable sections of the NEC.

6.2 Solar Ready Building Design

An important part of including PV in any building design is providing adequate methods of making sure that power via wiring from the PV system on the rooftop can travel to where it needs to end up for interconnection. Therefore it is helpful to determine equipment locations and where rooftop penetrations or extra conduits to the rooftop should be provided. Designing for this before building will save time and effort when it comes to building, as holes can avoid being drilled in a newly finished roof and any wireway or conduit for electrical wiring can be installed as the building is constructed. Therefore, collaboration for equipment locations and interconnection methodology is highly stressed to ensure the smoothest PV installation possible once the building in completed and ready.

Figures 10 and 11: Examples of how conduit has been pre-installed to ensure the building is PV-ready.

7 Economic Analysis

7.1 Federal ITC

Following the passage of the Inflation Reduction Act of 2022 (IRA), the Solar Investment Tax Credit (ITC) was vastly expanded and extended to 2032. The ITC is a 30% tax credit, meaning that a system owner can deduct 30% of the total system cost as credit on their taxes. The expanded ITC now allows for a "Direct payment" option for tax-exempt organizations as well as state and local governments to claim this credit in the form of a check for 30% of the project cost.

The expanded ITC also had provisions for potential adders that the project can apply for. At the writing of this report, many details for these adders are still being determined by the Treasury Department, but the current state of the program is as follows;

- 30% Base ITC
- 10% Bonus for Meeting Domestic Content Minimums
  - System must include 100% domestic steel/iron. Treasury is still determining percentage of total system to be made domestically
- 10% Bonus for Systems in "Energy Communities"
  - "Energy Communities" defined as former coal towns, brownfield sites, or communities with a % employed in the oil sector
- 10% Bonus for Systems in Low-Income Communities or on Indian Land
- 20% Bonus for Systems on Qualified Low-Income Residential Buildings

The IRA also allows the system owner to opt for an alternative Production Tax Credit (PTC) instead of the ITC. At the writing of this report, SDA has determined given the current state of the program that the only time the PTC is more advantageous than the ITC is for systems that are priced less than $1.00/W.

7.2 Net Metering

Net metering is referred to as 20 CMR 18.00 under Massachusetts regulations. Net metering allows for the energy that is produced by a PV system to be sold back to the grid at a given rate. Facilities where the host customer is an individual or company are deemed "private", while facilities whose host customer is a municipality or other governmental entity are deemed "public". Generally speaking, private net metering facilities earn a net metering credit for 60% of their net excess kilowatt hours that are exported to the grid. On the other hand, public facilities are entitled to a net metering credit worth 100% of their net excess kilowatt hours.

The net metering tariff requires that electric companies must have separate net metering caps for public and private facilities to limit the amount of projects that can apply for net metering and defines the caps as a percentage of the utility's highest peak load. For National Grid, the private cap is 7%, or 359MW of capacity, and the public cap if 8%, or 410MW of capacity. At the writing of this report, the private cap in

National Grid territory is full, and the public cap has 2.5MW of capacity left. SDA is hopeful that this project will be able to apply for a cap allocation, but the project will be unable to apply for allocation until National Grid has reviewed the system and given its permission to install, which may be some months or even years in the future, at which time the cap may be full. The DPU currently has docket 21-100 open, and is in the process of changing the language of the tariff relative to the net metering cap. At this time, SDA cannot comment on if the new rules will expand the cap for this facility.

7.3 Massachusetts SMART Program

It is the understanding of SDA that this project will seek the ILFI Zero Energy Certificate, which will require that the system owner hold the Renewable Energy Credits (RECs) that the system produces. This will be mutually exclusive with the Solar Massachusetts Renewable Target Program (SMART), which requires that the utility owns the rights to all RECs produced by the system. This report includes separate financial models for the system to examine the difference between if the system has the SMART incentive or not.

7.3.1 Background on SMART

The SMART program is referred to as 225 CMR 20 under Massachusetts regulations. Unless stated otherwise, all information discussed in this section is taken from this tariff. There are two main goals of the SMART program; first is to provide an easy to predict, long term incentive amount that allows stakeholders to calculate the value provided by their PV system. The second goal is to design incentive payments such that the overall incentive received is the same for both a net metered facility and a standalone solar generation facility.

The original SMART program includes provisions for 1,600 MWac of solar capacity, a portion of which is allocated to each investor owned utility in Massachusetts. Utilities with allocations include: National Grid, National Grid Nantucket, Eversource East (formerly NSTAR), Eversource West (formerly WMECO), and Unitil. Municipal electric utilities do not participate in the SMART program. In October of 2020, the SMART program was expanded to include an additional 1,600 MWac of solar capacity.

To be eligible for the SMART program a project must be under 5 MWac, be located in Massachusetts, and use solar photovoltaic technology. This project in Woburn would be serviced by Eversource East and is under 5 MWac in size. Thus the PV system slotted for the roof is eligible to participate in the SMART program.

Please see section 7.3.6 for detailed info about the current state of the SMART program.

7.3.2 Block Capacities

As mentioned in the previous section, for the original SMART program, the 1,600 MWac of capacity was divided among the utilities in Massachusetts based on peak total load for the 2016 calendar year. National Grid delivered 45.01% of Massachusetts's total electric load during that time and thus received 720.178 MWac of capacity under the program. In the original SMART program, these total capacities were divided into 8 equal sized capacity blocks. For National Grid, blocks 1-8 are 90.022 MWac each. Additionally, each block is further divided with 25% of the block being set aside for projects equal to or less than 25 kWac.

For the expanded SMART program, the 1,600 MWac was divided according to peak total load for the 2018 calendar year. National Grid delivered 45.23% of Massachusetts's total electrical load, and received 723.726 MWac of additional capacity. Each of the subsequent 8 blocks are 90.466 MWac each.

As of the writing of this report, National Grid has yet to utilize it 458.3271 MWac of its allocated capacity under the expanded program.

The compensation rate in the first block begins with using the base incentive rate as determined in the competitive RFP (see section 7.3.3). For the first 8 blocks, once a capacity block is has been filled, the compensation rate in the subsequent block of capacity will have the base incentive rate decline by 4%. This rate was reduced to 2% for blocks 9-16 set forth in the expanded capacity block. For example, if this project was submitted to the SMART program while block 1 was still open, it would have received a base incentive rate of $0.15563 per kWh. If these projects are unable to be submitted to block 1 and are instead installed under block 2 they will receive a base incentive rate of $0.14940 per kWh. The base rates for each block for National Grid is shown in **Table 4**.

Original SMART	**Block 1**	**Block 2**	**Block 3**	**Block 4**	**Block 5**	**Block 6**	**Block 7**	**Block 8**
	$0.15563	$0.14940	$0.14343	$0.13769	$0.13218	$0.12690	$0.12182	$0.11695
SMART Expansion	**Block 9**	**Block 10**	**Block 11**	**Block 12**	**Block 13**	**Block 14**	**Block 15**	**Block 16**
	$0.11461	$0.11232	$0.11007	$0.10787	$0.10571	$0.10360	$0.10153	$0.09949

Table 4: Utility Base Rate Blocks - The first block price is determined through a competitive RFP, base compensation declines 4% in each subsequent block as block capacity fills for the first 8 blocks, 2% for the remaining 8. Taken from Capacity Block Rate Guidelines, available from CLEAResult at http://masmartsolar.com/

7.3.3 Base Incentive Rate Determination

The base incentive rate was determined by a joint utility issued, statewide, open, competitive RFP for 100MWac of solar aggregated statewide. To be eligible for RFP, the solar project had to be sized between 1 and 5MWac. For each individual project submitted to the RFP, the solar developer would also include an incentive rate in the form of $/kWh that they would need in order to make the project profitable. The incentive rate they could request was capped at $0.17/kWh. Averages of the requested incentive rates, calculated separately for each utility, were then used as the base incentive rate for Block 1. The base incentive rate National Grid territory was set at $0.15563.

7.3.4 Base Compensation Rate Factor

The base incentive rate is further modified by a compensation rate factor and this compensation rate factor is determined by the size of the project. **Table 5** shows the criteria for each rate factor.

Generation Unit Capacity	**Base Compensation Rate Factor (% of Current Block's Compensation Rate)**	**Term Length**
Low income less than or equal to 25kWac	230%	10 years
Less than or equal to 25kWac	200%	10 years
Greater than 25kWac to 250kWac	150%	20 years
Greater than 250kWac to 500kWac	125%	20 years
Greater than 500kWac to 1000kWac	110%	20 years
Greater than 1000kWac to 5000kWac	100%	20 years

Table 5*: Base Compensation Rate Factor*

As can be seen in the table, the term length varies for projects below 25kWac as compared to projects above 25kWac. Since commercial projects are typically larger than 25kWac; this effectively means commercial projects under the SMART program would receive a 20-year contract length while residential projects would receive a 10-year contract length. For the fire station, at 245kWac we would expect 150% base rate factor and a term length for 20 years.

7.3.5 Compensation Rate Adders

In addition to receiving a rate factor based on project size there are also rate adders based on project location, project off-taker, and project technology. These are summarized below.

Project Location/Type	Adder Value ($/kWh)
Building Mounted	$0.01920
Floating Solar	$0.03000
Located on Brownfield	$0.03000
Located on Landfill	$0.04000
Canopy Solar	$0.06000
Agricultural Solar	$0.06000

Off-taker	Adder Value ($/kWh)
Community Shared Solar	$0.03064
Low Income Property	$0.03000
Low Income Community Shared Solar	$0.05530
Public Entity	$0.03686

There is a $0.01 per kWh adder for solar tracker systems as well as a variable adder for including an energy storage system coupled with a PV system.

Similar to the capacity blocks for solar projects each off-taker compensation rate adder has its own tranche capacity. The first tranche size for each rate adder is 80MWac. Once the first tranche is filled, that particular adder will have its value decline by 4% for the next block. For example, if 80MWac of solar projects qualifying for the public entity rate adder are submitted statewide, the tranche for that adder will be closed and any new public entity solar projects will fall into the second tranche. The beginning value of the public entity adder is $0.04, thus in the second tranche the value would be reduced by 4% to $0.0384. Each tranche size moving forward will be 80MW.

Projects may only qualify for one adder from each category. For example, the canopy and agricultural adders are mutually exclusive under the SMART program. Thus, a solar tracker system mounted on a landfill with battery storage and public off-taker would be eligible for an adder from each category (project type, off-taker, solar tracker, and battery storage).

7.3.6 Current SMART Incentive Outlook

As of the writing of this report, National Grid is on block 10 of 16 of its SMART allocation per the SMART expansion.

This project would be split into two systems, with one able to utilize the “Building Mounted” incentive adder while the ground mounted system would not. If this system is also owned by the town of Williamstown (or another public entity with an associate public ID from the DPU), it will qualify for the “Public Entity” incentive adder. Since the estimated date of completion is unknown at this time, SDA will assume that this project will qualify for Block 11 in National Grid, Tranche 2 for the building mounted added, and Tranche 3 for the public entity adder.

The base compensation rate would be $0.16511/kWh (the eleventh block compensation rate multiplied by 1.50 for being a system size of 25kWac to 250kWac) for both systems. Additional rate adders of $0.01920/kWh from the second tranche of the building mounted adder will be added to the rooftop system, and $0.03840/kWh for public entity adder will be added to both systems. Collectively, this results in a total compensation rate of $0.22271/kWh for the rooftop system and $0.20351/kWh for the ground mount system.

Currently, since the proposed building's National Grid rate class is unknown, SDA assumes the site will use a G-2 WCMA rate. Since this project will ideally be behind the meter, the estimate value of energy based on the 3-year basic service average for that rate will need to be subtracted from the total compensation rate in order to determine the total solar incentive payment. The value of energy was calculated to be $0.15041/kWh, resulting in a solar incentive payment of $0.07230/kWh for the rooftop system, and a solar incentive payment of $0.05310/kWh for the ground mount system.

7.4 Direct Ownership vs. PPA

In this report, SDA examines two methods of procurement for the PV system in question; Direct Ownership and a Power Purchase Agreement (PPA).

Direct Ownership is where the customer will take full ownership of the system, incurring all immediate upfront costs directly, and also being responsible for all operations and maintenance of the system. This includes recommended yearly commissioning of the system, and any and all repairs that may be required in order to maintain the function of the array. With the direct ownership model, the customer benefits from all revenue and savings provided by the PV system, including (but not limited to); the avoided cost of energy, net metered energy, and any state or federal incentives.

A Power Purchase Agreement is a method of PV system procurement where the customer would enter into an agreement with a third-party PPA provider, who would be the one who owns the system outright. Under this arrangement, the customer would pay no money upfront for the system. However, the third party owner would benefit from all the revenue and incentives associated with the system. There are a variety of pricing structures that could be implemented. The first being a roof lease in which the third party owner pays the property owner a monthly (or yearly) lease payment for the right to construct and operate the system on the owners property. A second pricing structure puts in place an agreement in which the property owner purchases the PV generated kWhrs at a reduced rate than that of the servicing utility. The exact structuring of these agreements typically varies from site to site and customer to customer depending on SMART block allocation, anticipated construction costs, site development costs, utility upgrade costs, net metering availability, the ability to interconnect behind an existing building meter, etc. At the end of the term, the customer would buy the system out for a cost close to zero.

Since the town is a public entity, and RFQ or RFP process would need to be offered, and PPA providers would send in bids to supply the town with a PPA agreement. SDA discussed this project in high level terms with a PPA provider we have worked with in the past, who indicated that the town would expect to see a $0.04/kWh savings on their electricity bill for a 20 year term. The PPA provider also indicated that it would be very likely that in order for the project to be economically viable to a PPA provider, the system would need to participate in the SMART program.

8 Payback Period (Basic)

Determining an accurate payback period for a PV system is a complicated endeavor due to the many moving parts and client variables. Tax attorneys are typically required to determine if a client can fully capture the ITC. Equipment and labor costs also adds to the complexity and uncertainty.

This report has made a number of assumptions and performed a basic analysis of the payback period of these proposed PV system options.

8.1 Assumptions

The following assumptions were made for this project;

1. Two options were examined;
    a. The project will apply under Block 11 of National Grid SMART program.
        i. The project tranche 2 building adder rate and tranche 3 public entity rate.
    b. The project will not participate in SMART and will hold all RECs.
        i. No PPA model was examined if the project does not participate in SMART
2. The building's electricity rate would be the G2-WMCA National Grid rate and would escalate at 3% per year.
3. Total annual load will be based off an early estimate of 300,000 kWh/year.
    a. A default NREL load profile for a similarly sized building in the northeast was used to determine 15 minute interval load data.
    b. Exported energy will be worth ~90% of the retail rate of imported energy for a municipal project receiving full net metering credits.
4. The system would qualify for the 30% direct payment ITC.
5. PV module degradation will be 0.54% per year.
6. A turn-key roof mount system would cost $2.75 per watt for the rooftop, $3.25 per watt for the ground mount, totaling $834,720.
7. Annual snow cover was not taken into account.

8.2 Results

The results of the payback period for total upfront cost of the system calculations are shown in the table below:

<table>
<tr><th>Option</th><th>System</th><th>kWdc</th><th>kWhr/yr</th><th>Estimated Const. Cost</th><th>Incentive Rate ($/kWh)</th><th>Incentive Payment (1 Yr)</th><th>Avoided $ of Energy (1 Yr)</th><th>Payback Period (yr)</th><th>20 Year Cash Flow</th></tr>
<tr><td rowspan="2">Direct (SMART)</td><td>Roof</td><td>140.16</td><td>150,376</td><td>$385,440</td><td>$0.07230/kWh</td><td>$10,872</td><td rowspan="2">$66,250</td><td rowspan="2">6.5</td><td rowspan="2">$1,467,756</td></tr>
<tr><td>Ground</td><td>138.24</td><td>165,346</td><td>$449,280</td><td>$0.05310/kWh</td><td>$8,780</td></tr>
<tr><td rowspan="2">Direct (ILFI)</td><td>Roof</td><td>140.16</td><td>150,376</td><td>$385,440</td><td>N/A</td><td>N/A</td><td rowspan="2">$66,250</td><td rowspan="2">8.1</td><td rowspan="2">$1,095,146</td></tr>
<tr><td>Ground</td><td>138.24</td><td>165,346</td><td>$449,280</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="2">PPA</td><td>Roof</td><td>140.16</td><td>150,376</td><td>N/A</td><td>N/A</td><td>N/A</td><td rowspan="2">$12,000</td><td rowspan="2">N/A</td><td rowspan="2">$322,444</td></tr>
<tr><td>Ground</td><td>138.24</td><td>165,346</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
</table>

Table 6: Simple payback period for each option.

This ROI includes a very preliminary avoided cost of electricity using the default Energy Toolbase load data for a medium sized nonresidential building located in Massachusetts. The above table reflects anticipated values if the systems were to be purchased by the property owner vs. if the system would participate in a PPA. Please refer to the full Energy Toolbase models for more detail.