

# The Producer Partnership Energy Independence Plan

May 2022

Authors:

Ayush Acharya, Joe Boland, Carrie Heilbrun, Helena Lam, Steven Yannacone

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## 1. Executive Summary

At the start of the pandemic in 2020, Matt Pierson, a fifth-generation rancher, founded The Producer Partnership (TPP) in Livingston, Montana to help food insecure people get access to fresh hamburger meat for hot meals. TPP is a non-profit focused on partnering with local Montana ranchers to transform excess cattle into hamburger patties to be donated to local food banks. The ranchers in return receive a tax deduction for the donated meat. In 2020 alone, TPP was able to donate 53,345 pounds of hamburger meat, and 42,622 pounds in 2021<sup>1</sup>.

TPP set out to expand their operations in 2021 by building Montana's first federally inspected, non-profit processing facility to be opened in 2022 on the Pierson ranch. In need of an energy supply for the new processing facility, Matt was weighing out the option to use a natural gas generator with natural gas provided by Northwestern Energy, the local Montana utility provider, and the option to self generate renewable energy with limited ability to interconnect to the grid. There is no available option to directly connect to the electricity grid due to the remote location of the processing plant on the ranch. Ultimately, NorthWestern Energy is the major vertically-integrated utility provider in Livingston, which means that they are the sole provider for electricity and natural gas for the area.

Given TPP's positive impact to society, The Producer Partnership has ultimately tasked the Yale team to devise an energy independence plan including a budget to utilize 100% renewable energy for the processing plant, if possible. This plan would also include social and environmental considerations that a renewable energy plan can create. The hope is that TPP's renewable energy powered processing plant can be an example that can be replicated in other locations across the U.S..

The major criteria for the renewable energy plan include:

- **Reliability** – ensuring that energy will be able to power 24/7 machinery, such as the refrigerators storing the packaged meat boxes
- **Cost effectiveness** – ensuring that the plant's operation costs are properly managed and in line with donated funds
- **Ease of development** – ensuring that the renewable energy and battery system is able to be fixed quickly and added to easily (creating time for Matt to take care of the ranch of expand operations)

The three options we considered include:

- **Wind and battery storage**

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<sup>1</sup>The Producer Partnership, 2021 Annual Report, <https://www.producerpartnership.com/2021-annual-report>.

- **Solar and battery storage**
- **Mix of solar, wind, and battery storage**

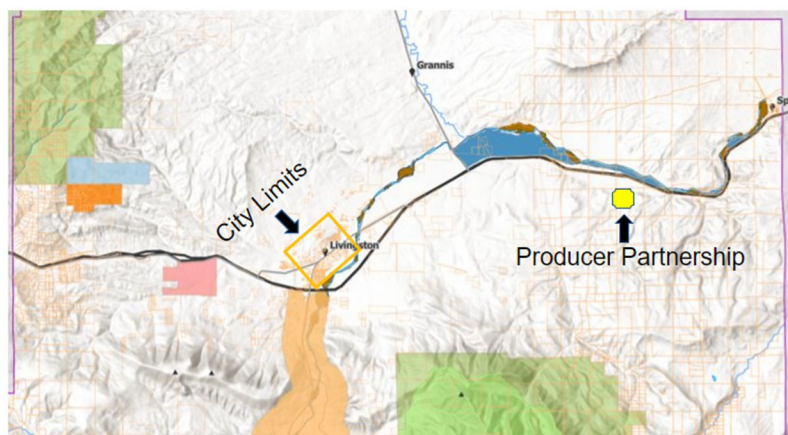
Based on our optimization of capital cost and reliability, we find that our most cost-effective system that can maintain “perfect” reliability (i.e., no dependence on the natural gas generator for backup) is the hybrid 150 kW solar – 150 storage – 20kW wind system. We recommend building out the solar + storage piece first, occasionally relying on the relatively cheap generator for occasional low-sun winter days, and later installing the 20kW turbine to eliminate reliance on the generator entirely.

In the subsequent sections, the Yale team will provide a short background about the processing plant location, local regulations, and zoning requirements, and the potential load profile for the plant. This will be followed by a summary of each of the three scenarios based on the load profile including the methodologies to create each scenario and our key findings based on our models. We will conclude with a discussion of the social and environmental implications of a renewable powered processing plant will have on the local community.

## 2. Background

Before building, we need to know what zoning code restrictions exist that will limit our build based on things like turbine height, solar panel land parcel coverage ratio, or visual impacts to the community. Montana zoning law is extraordinarily friendly to wind and solar, not because of any specific provisions *encouraging* their adoption, but because hardly any restrictions *limit* their adoption. Out of all Montana towns, Bozeman is the only one with any solar PV-specific regulation<sup>2</sup>. TPP’s location renders it free from virtually any restrictive zoning code. The operation is outside the City limits of Livingston and also outside the five citizen-initiated special zoning districts and one county-initiated special zoning district of Park County<sup>3</sup>.

Figure 1: Park County Map of Zoning Districts & Producer Partnership’s Property



<sup>2</sup> Maneta, Diana, Permitting Processes for Solar Photovoltaic Systems in Montana, Montana Renewable Energy Association, Montana Dep’t of Env’tl. Quality, July 2013, Page 11.

<sup>3</sup> Park County, “Zoning,” <https://www.parkcounty.org/Government-Departments/Planning/Zoning-Applicaitons/>. Last visited May 11, 2022.

Items still needed for any construction project include a State Building Permit from the State Building Inspector (likely 1.6% of panel cost), and an \$40-120 Electrical Permit, obtainable online by any electric contractor<sup>4</sup>.

Some best practices based off the law within the nearby City of Livingston include keeping turbine height below 150 ft and preferably to 100ft, distancing all turbine construction 100% of tower height away from all property lines, painting turbines in “subdued, neutral tones” such as grey or brown, and keeping a \$1 Million general liability insurance policy<sup>5</sup>.

## 2.1 Load Profiling

The Producer Partnership plant will not be operational till late summer of 2022, therefore, one of the challenges in deriving the load profile was the unavailability of historical energy demands for the facility. In order to get a rough estimate of the energy demand, we initially tried to derive the load profile based on the installed load capacity and inputs from plant owners on expected operation hours. However, a typical meat processing plant can have highly segregated hourly demand profile because of the variety of functions of each equipment type. The cooling demand spreads out 24/7 for entire week, whereas other units like fabrication, packaging and slaughterhouse are in operation only during business hours (8am – 5pm) over weekdays. Projecting a reliable electricity demand estimate based on only inputs like expected operational hours and installed load capacity can be highly inefficient, as each facility has different utilization factor; a typical refrigeration unit can sometimes perform at well below its rated nameplate power rating<sup>6</sup>. These are largely plant specific data which depend on the behavioral trends of plant owners and cannot be replicated from other plants unless they are identical to the design plant.

We initially attempted to compartmentalize loads based on function of equipment<sup>7</sup> and extrapolated load profiles based on other medium sized meat processing plants<sup>8</sup>. Refrigeration and Freezer units are the most energy intensive load components in a meat processing plant which accounts for approximately 25 percent of total electricity consumption in representative medium scale plants in the mid-west US. Likewise other units have different operational energy data. In regards to diurnal patterns of load profile, the medium scale meat processing plants from cited work gives an indicative

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<sup>4</sup> Maneta, Diana, “Permitting Processes for Solar Photovoltaic Systems in Montana, Montana Renewable Energy Association, Montana Dep’t of Env’tl. Quality, July 2013.

<sup>5</sup> Livingston City Code §30.59.1.

<sup>6</sup> Larson, Ben, Robert Davis and Jeffrey Uslan. “Is Your Refrigerator Running? Energy Use and Load Shapes for Major Household Appliances.” (2014). <https://www.semanticscholar.org/paper/Is-Your-Refrigerator-Running-Energy-Use-and-Load-Larson-Davis/6d19dfeb86a60ba6d25bc1e7cd1020bd705d8b6f>

<sup>7</sup> Li, S, Ziara, RMM, Dvorak, B, Subbiah, J. Assessment of water and energy use at process level in the U.S. beef packing industry: Case study in a typical U.S. large-size plant. J Food Process Eng. 2018; 41:e12919. <https://doi.org/10.1111/jfpe.12919>

<sup>8</sup> Shafiullah, GM, Bond Watson, Christopher Lund, Md M. Rahman, Gloria Rupf, and Jonathan Whale. 2017. "Voltage Optimisation Technology for an Australian Abattoir—A Techno-Economic Evaluation" Energies 10, no. 11: 1764. <https://doi.org/10.3390/en10111764>

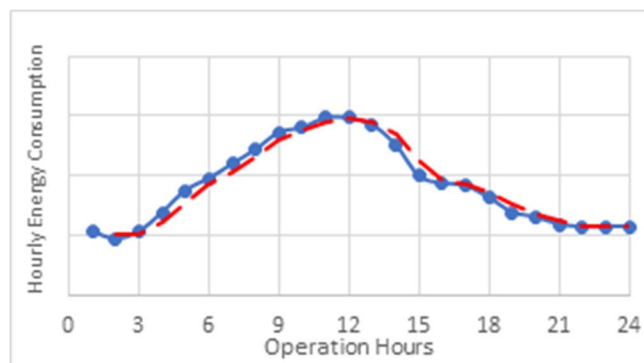
estimate for the Producer Partnership plant, but again is largely speculative as it differs from Producer Partnerships in terms of all operation features including size, location and equipment characteristics.

The Shafiullah et al. paper discusses that typical electrical load profiles for a meat processing facility are highest during boning and the initial stages of carcass cooling, whereas a typical weekend electricity consumption is relatively constant throughout the day. All of their findings are based on site-based data collected from three medium scale meat processing plants that have daily energy demand of >20,000kWh/day. This was the more relevant literature we could find for a comparably sized meat processing plants, and is >50x times larger than the size of Producer Partnership. As such, we were reluctant in using these estimates and load profile for our study.

*Table: Load Compartmentalization based on Function of different Equipment Types*

Units	Electricity Consumption Share
<b>Refrigeration Unit</b>	24.50%
<b>Fabrication and Packaging</b>	18.40%
<b>Engine Room</b>	17.60%
<b>Slaughterhouse</b>	13.90%
<b>Rendering</b>	11.20%
<b>Wastewater Treatment</b>	6.50%
<b>Other</b>	7.90%

*Figure 2: Daily Load Profile for Medium Scale Meat Processing Plant*



The Producer Partnership processing plant is based on a unique mobile and modular meat harvest and processing (MMHP) system manufactured by Friesla; a turnkey meat processing equipment supplier based in Everson WA. The MMHP is a relatively newer solution provided by Friesla therefore, only few other plants have adopted this solution so far. Therefore, to get an accurate estimate of gathered monthly energy demand we contacted Friesla; from them we were able to gather monthly utility bills from other similar sized processing plants in Texas and Wyoming, that are based on MMHP. For this study, the Wyoming bill was preferred as it offered better resemblance in terms of weather conditions to Montana. Although the Wyoming plant had a similar design but used a slightly different refrigeration unit. However, the technical representative from Friesla who oversees Producer Partnership as well assured us that the energy demand for both plants will be largely similar. As a result, we were able to estimate the daily energy demand based on the highest energy demand month from the utility bills that we received which

gave a figure of 441kWh/day. Due to the constraint of not having an already operational plant, the 441kWh/day figure was the best metric for us to base our simulations and system design on. Likewise, without a comprehensively logged hourly consumption data for the plant, we were limited to using a flat average demand curve spread evenly across all hours of the day. Going forward, we recommend installing an energy data logger on-site once the plant is under operation that would give a better estimate for rendering a daily load profile.

**\*Based on Electricity Consumption Data for a Near-Identical Plant in Wyoming**

<b>Monthly Electricity Demand (kWh)</b>	13,230
<b>Average Daily Electricity Demand (kWh)</b>	441

This energy use entails that the current Caterpillar 375kW Natural Gas Generator would be average operating at 18.26kW for any given hour, or about 5% of max capacity. A 375 kW generator running at 25% capacity consumes 1,724 ft<sup>3</sup>/hr<sup>9</sup>. If we assume the rate of natural gas consumption for a generator operating at 5% capacity is proportional to the rate at 25% capacity (a conservative estimate), then the generator can be expected to consume on average 340 ft<sup>3</sup>/hr, or 2,942 ft<sup>3</sup>/year. At a 2020 Montana commercial natural gas cost of \$6.98/thousand ft<sup>3</sup>,<sup>10</sup> that amounts to a total annual cost of \$20,537 and a 25-year cost of \$513,430. Note that these estimates are over 2x as high as those originally quoted because they take into account generator efficiency. If we can achieve 100% reliability without resorting to any natural gas use and we can resell the generator for the price paid for it (\$149,900), we would avoid \$663,330 in total electricity costs over 25 years.

### 3. Wind Outlook

#### 3.1 Methodology

When siting large-scale wind, financing professionals commonly require at least 3 years of wind speed data, captured by SODAR, LIDAR, or met tower at the exact project location. Given that Producer Partnership expects to be up and running within just a few months, there was not time to secure 3 years of wind data at the project site prior to our first operation date. However, we can model based off proxy data. With the help of Keith and Cory at NOAA's local Billings, MT office and Professor Xuhui Lee and Tarek Kandakji at Yale, we were able to locate 10-year hourly ASOS wind speed, direction, and gust data for Livingston Mission Field Airport (LVM). Similar ASOS 3-year hourly Big Timber, MT data is also available, and referenced in determining average speed, but was not otherwise extensively used in modeling wind patterns due to the shorter historical measurement period. All reference wind pattern estimates were therefore taken at ASOS' standard measurement height of 33 ft above ground-level.

<sup>9</sup> Generator Source, "Approximate Natural Gas Consumption Chart," [https://www.generatorsource.com/Natural\\_Gas\\_Fuel\\_Consumption.aspx](https://www.generatorsource.com/Natural_Gas_Fuel_Consumption.aspx). Last visited May 11, 2022.

<sup>10</sup> U.S. Energy Information Administration, "Natural Gas Prices," April 29, 2022, [https://www.eia.gov/dnav/ng/ng\\_pri\\_sum\\_dc\\_u\\_smt\\_a.htm](https://www.eia.gov/dnav/ng/ng_pri_sum_dc_u_smt_a.htm).

Elevation does not vary to any significant degree between Mission Field Airport and our project site at 356 Frontage Road East, although relatively more surrounding hills around the Airport may slow speeds relative to the project site. As seen from the photo below - oriented West to face the dominant wind - Producer Partnership is located on vast, open, flat landscape with few obstructions to block the wind.

Figure 3: Westward-looking View (Facing the Wind) of 356 Frontage Rd. East, Livingston MT, 59047



We extrapolated the Mission Field Airport annual and season wind patterns to the average wind speed at 100 ft originally quoted to us by Company B's 10-year wind model, which was 14.8 mph (6.6 m/s). That is, we assume that the observed annual and seasonal wind speed deviations from the 12.96 mph (5.8 m/s) Mission Field Airport average at a 33ft equally vary (by percentage change) around the 14.8 mph (6.6 m/s) expected average annual speed at 100 ft height. An annual average wind speed in the range of 13-15 mph is also supported by the Big Timber data, at which the observed annual average speed is 14.2 mph (6.3 m/s) at 33ft. More to the point, a speed of 14.8 mph is not far off what would be predicted by a re-arranged Wind Profile Power Law equation:

$$U_2 = U_1 * \left(\frac{Z_2}{Z_1}\right)^{\frac{1}{7}}$$

Z1 = Height of Lower Speed (U<sub>1</sub>) Measurement; Z2 = Higher Height at Which Turbine Will Be Placed;  
 U1 = Speed at Height Z<sub>1</sub>; U2 = Speed at Height Z<sub>2</sub>

With our inputs:

$$U_2 = 5.79 \text{ m/s} * \frac{(30.48\text{m})^{1/7}}{10.06\text{m}}$$

$$U_2 = 6.78 \text{ m/s (15.17 mph)}$$

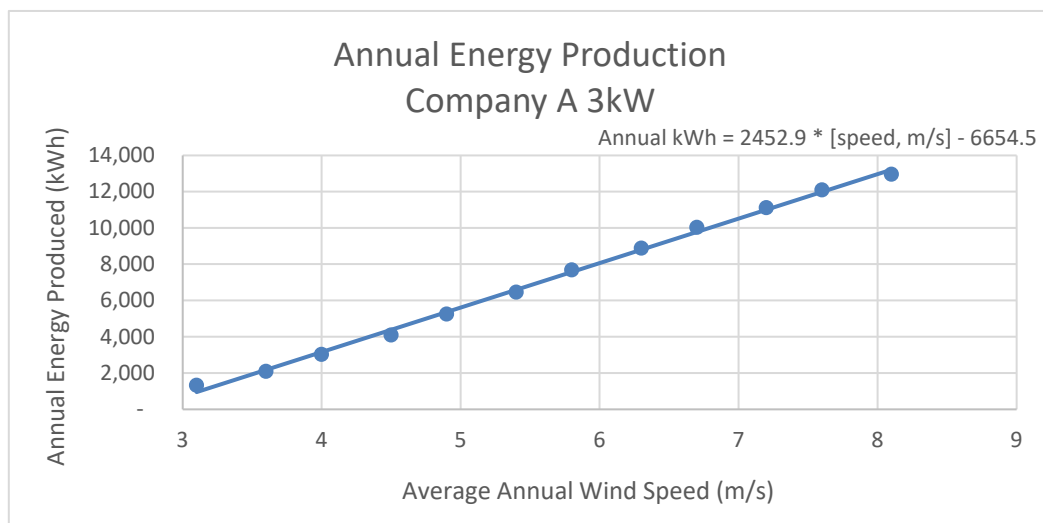
The exact average annual speed and seasonal deviations could only be captured with at least one year of SODAR data, and Company B's initial number does not take into account the speed accelerating/decelerating effects of nearby topography (not to mention the last time we called they had dropped the estimate to 13 mph). Still, 14.8 mph (6.6 m/s) at 100ft is a reasonable estimate, and the one that we primarily work off for the purposes of system sizing.

Day-night diurnal variation is also measured, but is not entered into calculations because day-night patterns at heights less than 40m are known to be unrepresentative of patterns at heights over 40m, and our hub height is close to that 40m threshold. See Appendix 3 for observed variation at 33 ft.

Unless otherwise stated, turbine production estimates are based off 100 ft tower height. Company B was the only company that offered clear tower height options. Company B's 80 ft lattice tower option shows promise, but according to the same company, wind speed drops 3 mph at 60-foot height. As discussed in more detail in the next section, this renders tower heights less than 70-80 ft impractical from any supplier.

All annualized energy production estimates are based off manufacturer numbers provided through manufacturer experts, websites, and brochures. Proprietary information learned through non-public phone and email conversations has been redacted. Beach Wind Energy (BWE) is the only wind company routinely mentioned by name, because they were our winning supplier. We obtained data for all turbine options in tabular Speed vs. Annual Production format, which appears to be industry standard. We plotted these points for each turbine model on a graph and used Excel's "trendline" function to create a speed-to-production function. As can be seen below, despite the cubic relationship of speed to power, the speed-to-annual-production relationship is almost perfectly linear for non-variable pitch systems over the relevant range of 3-9 m/s averaged speeds. To be fair, a "Power" relationship also often fits along these ranges, and does so with a nearly cubic 2.7 exponent too, but only fit the points best when assessing BWE's Variable Pitch 10kW and 20kW turbines. See appendix for all Speed vs. Energy graphs:

Figure 4: Relationship Between Average Speed and Annual Energy Produced for a Company A Turbine



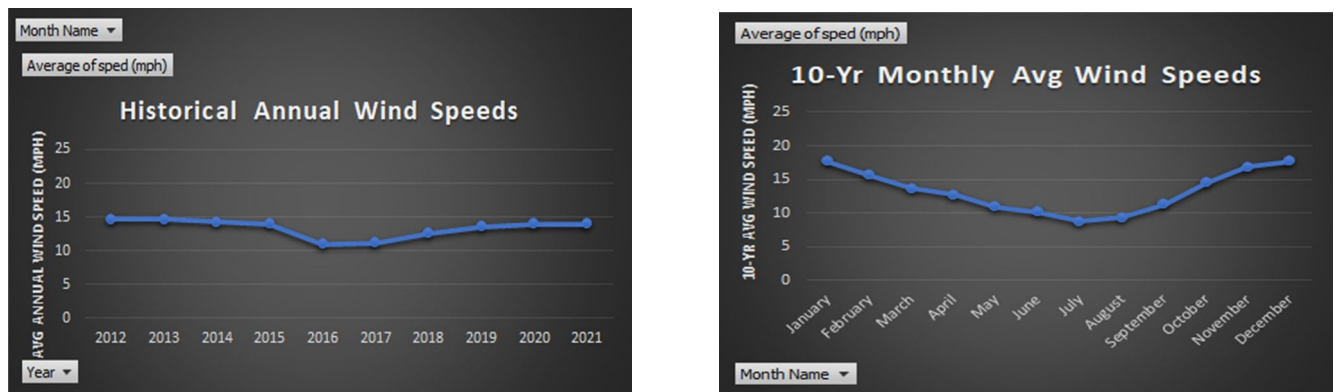
Our predicted annual wind speed of 14.8 mph (6.6 m/s) - or lower as appropriate for varying Company B tower heights - was plugged into each of the resulting Speed vs. Power equations to estimate annual energy production. The resulting annual kWh-per-turbine figure was used to size the required number of systems, space, total cost, and cost-per-kWh in 2 scenarios: one where average production equates to consumption (160,000 kWh), and one where the system is sized to meet the 10-year monthly average minimum wind speed (occurring June 2019).

### 3.2 Speed Analysis Results

When sizing the wind system to meet near-100% of 160,000 kWh annual (13,333 kWh monthly) demand, we must plan to meet not the best conditions, but the worst conditions. We can begin to understand what a bad wind period looks like by first analyzing the lower bound of wind speeds in an atypically bad year. As apparent from the graphs below, the worst years within the last decade were in 2016 and 2017, and represented roughly 20% (-3mph) below-average variations.

This issue could easily be solved with batteries if the variations occurred in intervals evenly spread across weeks of the year. Unfortunately, the 10-year aggregated monthly average data reveals a larger problem: regular months-long dips in wind speeds during the summer, which, if building to average wind speed, would require batteries with 5-month storage (with energy capacity of tens of thousands of kWh) to maintain near-100% renewable supply at reasonable build cost. The worst month's deviation (July) from average wind speed represents a -48.3% (-4.2 mph) shift from the average across the year:

Figure 5: Historical Annual Average and 10-Year Average Monthly Wind Speeds at Mission Field Airport at 33ft.

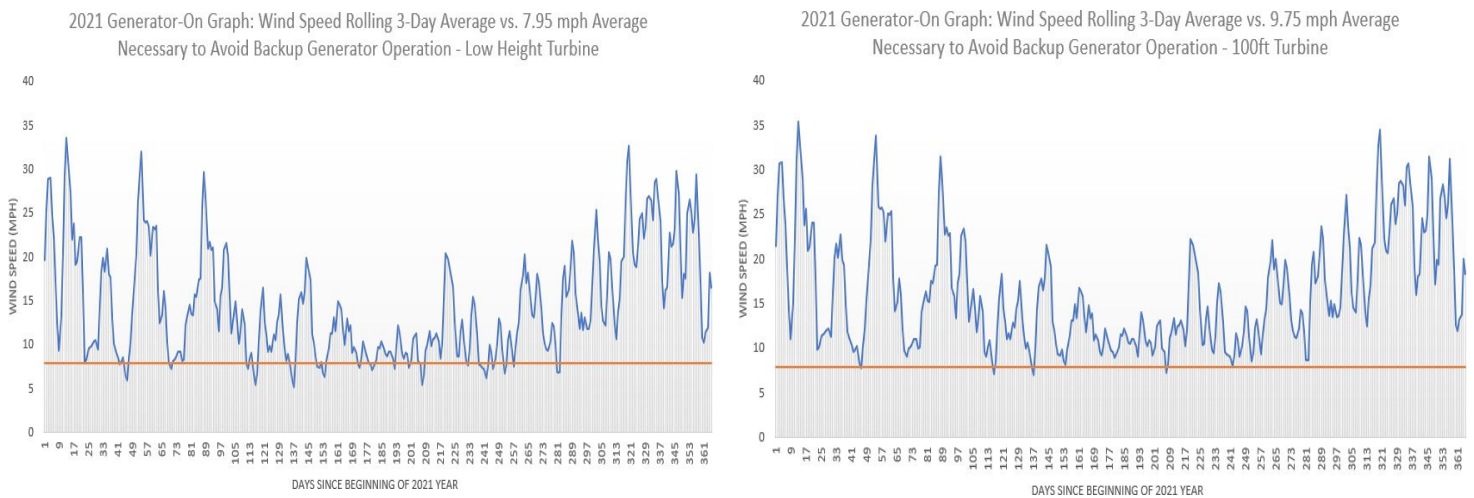


The combination of an atypically bad year and a typically bad month results in 33-ft speeds of 7.95 mph (extrapolated to be 9.75 mph at 100 ft), occurring in July of 2019. While actually only 9.9% below the monthly average for July (within-month deviations are not by themselves necessarily large), this speed is 39% below annual average (-5.01 mph). If the relationship between wind speed and energy generated were a 1:1 relationship, we would need to oversize the system about 1.6x to meet average energy demand operating with 40% below-average wind speeds.

But while the relationship between wind speed and energy can be represented linearly at our typical range of speeds, it is not a 1:1 relationship nor does it begin at 0,0. Thus, in sizing the system to meet the 10-year monthly minimum, we need to use one or more of the equations created from the manufacturer data. Plugging this 9.75 mph 100-ft speed into the Company B equation (picked to be typical of most turbines) and comparing that to energy produced from the average speed yields that the system must be sized 2.81x that needed for a system sized to provide 100% of energy if annual speeds remained the same year-to-year and month-to-month. Based off a 160,000 kWh system size then, we would need to build to produce 449,435 kWh in order to meet minimum monthly demand. As shown in the next section, this necessarily drastically increases both expense and required space.

Furthermore, even with such a build, batteries would not be able to fully support the day-to-day intermittency of wind. To analyze the issue, we built out what 3-day rolling wind speeds look like. The idea is that, on the first day, our oversized system would provide, on the second day batteries could provide, and it is only on the third day that we would need wind speeds to surpass the minimum monthly average again if the system is to work. Based on a typical average-speed year (2021), at a 33ft height, we still require additional energy input to meet demand on 41 days (11%) and 17 periods throughout the year. But even at high heights where it is assumed that all speeds are 1.8 mph faster, we would still require additional generator or other power on 5 days (1%) and 4 periods, unless we overbuilt the system even more. The minimum 3- day rolling average at low height (and at 100ft in a particularly bad year/month) of 3.95 mph is actually lower than all turbine options' cut-in speed, meaning that *regardless* of build size we could not completely meet 100% of energy needs with wind energy alone.

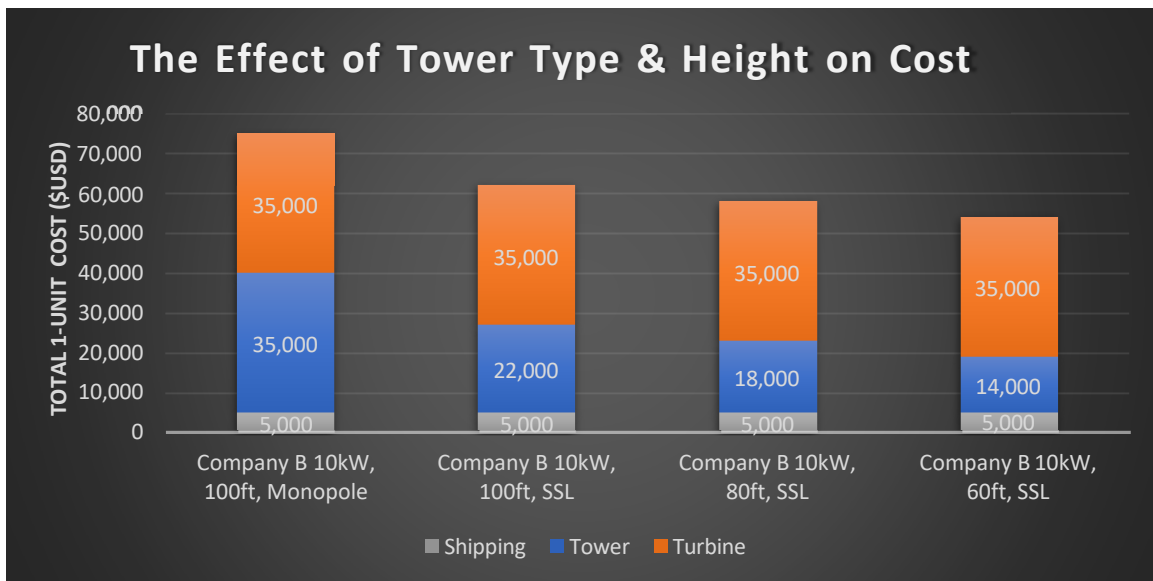
Figure 6: 2021 Observed Wind Speeds Versus Minimum Average Speed at Which Wind Will Not Provide 100% Energy and Nat. Gas Generator (or Solar) Energy Must Supplement; at 33ft (left) and 100ft (right)



### 3.3 (Near) 100% Wind Results

We explored a variety of turbine companies and sizes, including (in order of size) the Primus Air 30, Primus Air 40, Zephyr Airdolphin, Company A's 3kW, Company B's 10kW and 15kW, BWE Variable-Pitch 10kW and 20kW, Aeolus 60kW (not available in North America), the NPS 60C (not available in North America), Company D's 100kW, and more. Towers for small-to-medium sized turbines are generally offered with 100 ft tower heights. For these small-to-medium sized turbines, the tower commonly makes up 30% or more of the cost, and where options are given, serious consideration should be given to lattice towers (\$14,000-22,000 depending on height), which seem to be about 40% cheaper than monopole towers (\$35,000). Where available, a guy wire setup should also be considered, since relatively high-altitude guy wire setups can be purchased for just \$5,000 or \$6,000, although less aesthetically pleasing than lattice or monopole towers. Of all turbine companies, Company B offered the most variety in terms of tower options. See below for a comparison of Company B towers by type and by height:

Figure 7: The Effect of Company B Tower Type & Height on Total Cost

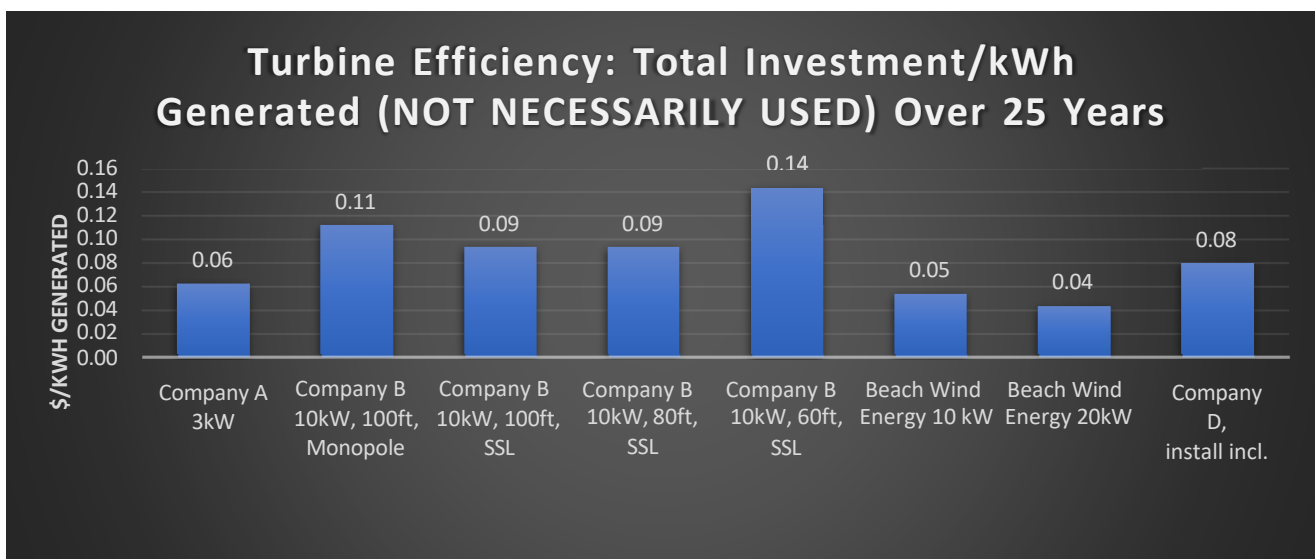


All tower numbers given above and throughout this report include the cost of charge controller and dump load, but do not include installation costs. Based on Company D's estimate for installation cost and the estimates given to us by Company B for installation of their 10kW turbines, installation & electrical work together will likely amount to an additional 20-30% of total cost where not already accounted for.

[redacted]

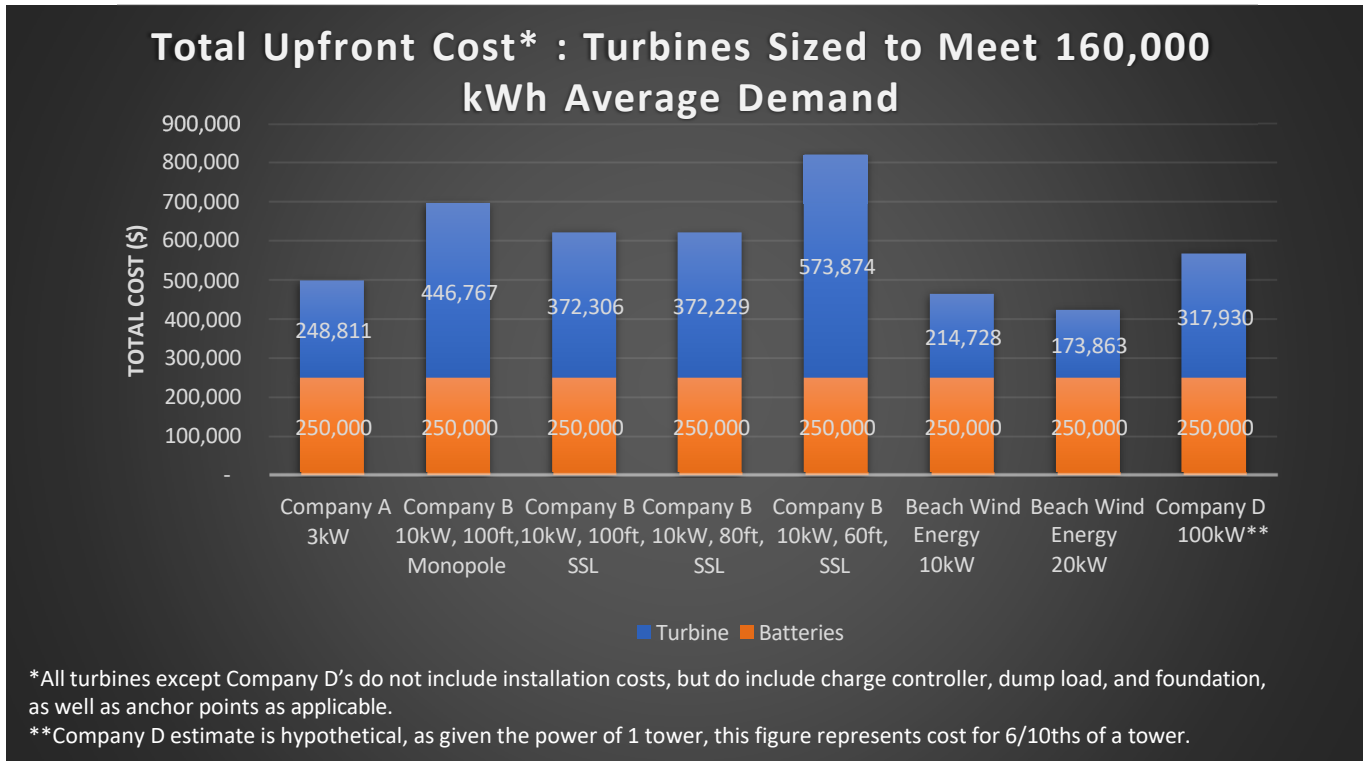
Because all of these turbines have vastly different capacities, it is best to analyze them according to their upfront cost *per kWh* produced over a 25-year lifetime. The differences can be stark. Note that, despite a .5 mph decrease in wind speeds at an 80 ft height (as modeled by Company B), the Company B 10kW with an 80 ft tower ends up in cost parity with the similar 100 ft tower variety due to the upfront savings of \$4,000 per tower. However, we should be wary of lowering tower height too much because a 3 mph decrease in wind speeds observed at 60 ft height (as modeled by Company B) kills the cost-effectiveness of the additional \$4,000/turbine upfront tower savings in dropping from 80ft to 60ft. Company A's turbine, despite its small capacity (3 kW), is highly cost-effective, although as will be shown, the space that would need to be occupied by the turbines to support our energy load is enormous. The Beach Wind Energy (BWE) Variable Pitch (BWE) systems are superior to all other models; among BWE systems, the 20kW is more cost-efficient than the 10kW version by a small margin. Our use of this turbine is reliant upon securing higher towers for similar cost, since the default offering is only 40 ft and 59 ft high for the 10kW and 20kW models respectively; however, the BWE representative has assured us that this special order can be met, and we do not anticipate this change to meaningfully impact cost savings or the final recommendations of this report.

Figure 9: Upfront Cost/kWh Generated Over a 25-Year Turbine Lifetime



So, what is the total upfront cost? First, we evaluate what the total upfront cost would be with the system sized to meet average annual demand. This scenario, despite heavy reliance upon relatively dirty natural gas backup for the low-wind 5 warmer months of the year, is useful to include for two reasons: first we see that wind can be as cost-effective or even lower-cost than solar. Second, and relatedly, if we were ever able to connect to the grid and sell back energy for at value, this build is one that would create net-\$0 annual average electricity cost each year, if compensated at retail rates. The least expensive options, as seen below, are (in order of cost-effectiveness) the BWE variable-pitch 20kW, the BWE variable-pitch 10kW, Company A's 3kW, the Company D's 100kW, and the 80ft Self-Supported Lattice Company B 10kW.

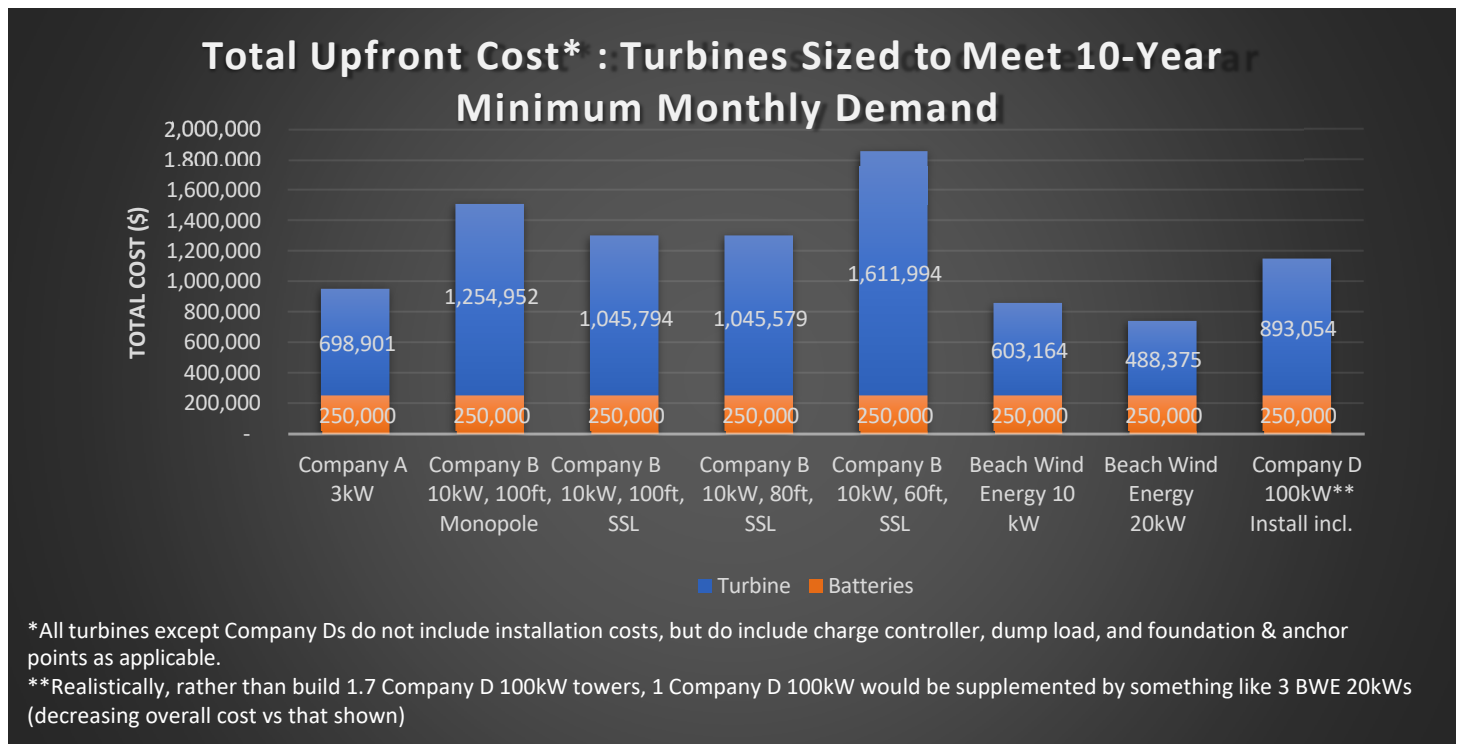
Figure 10: Total Upfront Cost of a 160,000 kWh/year System



Due to the relatively even production of wind in both the day and nighttime, it is (very roughly) estimated that 125kW of batteries (and likely less), priced at \$2,000/kW, are needed to meet daily energy demand.

Unfortunately, the above image is not close to the reality of what we would need to be nearly 100% renewable during the low-wind summer months. In order to do that, we need to oversize the system 2.8x (see Methodology section for details). At such expanded capacities, even our cheapest option, the BWE 20kW, together with our estimated 100kW battery expense, is just about at parity with alternative and equally reliable Solar + Storage options, coming in at a total price tag of \$738,375. Not to mention, such an option comes with additional uncertainties as to our ability to secure a higher tower for the BWE 20kW (a relatively minor concern) and as to actual wind speed at 100ft at our specific site (a larger concern).

Figure 11: Total Upfront Cost of a 449,435 kWh/year System (Sized to Meet Monthly Minimum Speeds)



It may appear above that the Company A and our Company B or BWE 10kW options are relatively competitive options as compared to the BWE 20kW or Company D’s 100kW option than they actually are. While it is true that on a cost basis these options are relatively competitive, the space they would occupy would at best be an inefficient use and at worst would be completely impractical. For optimal performance, wind turbines must be spaced 5x the rotor diameter away from each other parallel to the predominant wind direction and 8x the rotor diameter downwind.<sup>11</sup> Wind power is based on the square of rotor diameter windswept area but distance between turbines is based on simple multiplication. Thus, for instance, a single BWE 20kW with rotor diameter of 9.8m occupies much less space per kWh produced than 2 Company B 10kW turbines with rotor diameter of 7m. By the same logic, 200kW worth of 20kW and 10kW turbines takes up much more space than 2 Company D 100kW turbines with rotor diameter 20.9m each. See appendix for an illustration of just how untenable this space-allocation reality is for 100% Company A 3kW or Company B 10kW setup.

This quantity of turbines can actually technically be supported by the plateau to the Southeast, but ultimately it was decided that the plateau should be reserved for a future large-scale, grid-tied wind operation using turbines of capacities equivalent to or exceeding that of Company D’s 100kW turbine.

Practical options for the site, therefore, are narrowed down to 8 BWE 20kW turbines (which would still push space limitations), 2 Company D 100kW turbines (which would oversupply

<sup>11</sup> Mitchell, Peter R., “Wind Turbine Separation Distances Matter,” North American Platform Against Windpower, June 2014, <http://www.na-paw.org/Mitchell/Mitchell-Wind-Turbine-Separation-Distances.pdf>.

energy), or a combination of the two, such as 1 Company D 100kW turbine and 3 BWE 20kW turbines. Ultimately, however, the most cost- and space-effective option involves use of wind as a *supplement* (an incredibly powerful one, to be sure, but still a supplement) to a Solar + Storage setup. This option is explored in section 5.

## 4. Solar + Storage Outlook

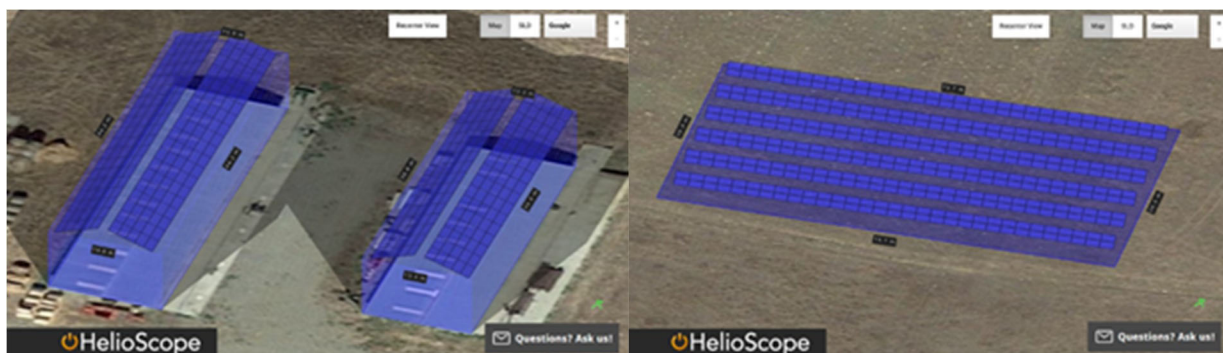
### 4.1 Solar Siting and Sizing: Methodology

#### Design Considerations and Mounting Options

The siting and placement considerations made during installation of a solar plant is one of the most significant factors that determines the margin of optimization for electricity yield. Producer Partnerships have two adequately sized rooftop spaces at their plant location. The client wanted to utilize this space prior to exploring the option for a ground-mount solar. However, both these building are located longitudinally at an east-west orientation, therefore, do not provide the most optimal conditions for roof-top mount PV system. Therefore, we took the approach to make quantitative comparisons between rooftop and ground-mount systems for the required size of solar.

Initially, configurations for both the systems were sized using HelioScope that allows us to overlay the PV system design over satellite imagery of the existing buildings and land configurations. The two rooftop spaces are a sloping roof design with a corrugated sheet structure, and offer a collective surface area of approximately 1,107 m<sup>2</sup>. All the simulation in HelioScope were performed using SunPower's CSP-18-72H 545Wp monocrystalline panel.

*Figure 12: Modelling Total Installed Capacity of PV for Available Rooftop and Fixed-Axis Ground-Mount Systems*



Furthermore, HelioScope was also used for quantifying the effects of shading. The analysis calculated the Plane of Array (POA) irradiance, which is a measure of the total amount of solar energy that is available to an array, based on the location of the array and the direction of the modules. POA irradiance is calculated at the module level and averaged across modules to generate system-level values that incorporates shading from row-to-row shading as well as other physical interferences from both near and far conditions were calculated from the simulation.

The annual electricity productions (AEP) estimate for different system options were simulated using the PVsyst software. A typical meteorological year data from Meteonorm 8.0 was used in the simulation based on a ground-based resource data that was extrapolated from an on-site solar resource measurement station located at a radius of <1km from the site location. The TMY data is based on a 15-year data range expanding from 1991-2005. Additionally, all typical loss factors and other parameter for a typical captive solar plant were incorporated in PVsyst for performing the simulation. The same 545Wp PV module from SunPower is used in PVsyst along with 3 units of a string inverter module of 62.5kWac capacity from SMA Sunny Tripower Series for the simulation. String inverters while not providing the same optimum generation benefits as a micro-inverter, is significantly more effective than a central inverter and comes falls under a medium price spectrum. Thus is a good fit for a commercial captive project such as this.

The output from a PV system, specially for a ground-mount system, is largely impacted by other critical design considerations. One of the prominent considerations is the use of solar tracking system with the panel mounting structures. Multiple simulations were run for different panel mounting configurations with AEP as the result metric. We examined AEP increases for different panel mounting systems that included (i) fixed tilt (base case), (ii) seasonal tilt adjusted, (iii) single axis tilt tracking, (iv) dual axis tracking. Likewise, we also simulated AEP results for bifacial panel option.

## 4.2 Demand and Capacity

### Total Installed Capacity

Based on results from HelioScope simulation, we found that collectively, the two rooftop spaces can house an approximate installed capacity of 192kWp of PV. The simulation was performed for an east-west racking configuration with a flush mounting system. The east-west tilt angle matches the slope angle of the rooftop. In terms of inter-panel spacing, inter-row and inter-frame spacings are set to zero to maximize the area available for PV with some space left at the crowning of the rooftop for maintenance. Likewise, some inter-module spacing is set to account for thermal expansion during warmer weathers.

For a ground-mount configuration, we had ample land to work with, therefore, we sized the system based on a predetermined size for the PV system. A total installed capacity of 200kWp was selected which required an area of 2,895 m<sup>2</sup>. The 200kWp capacity was used based on the best rating scenario from the simulation results generated by NREL's System Advisory Model (SAM) which is the optimum size of the PV system when used with a 200kW battery storage system. Therefore, the rooftop option does provide a 2.56x times greater optimization index for space to installed capacity ratio with a fraction of 5.76 m<sup>2</sup>/kWp in comparison to the latter case with a fraction of 14.47 m<sup>2</sup>/kWp.

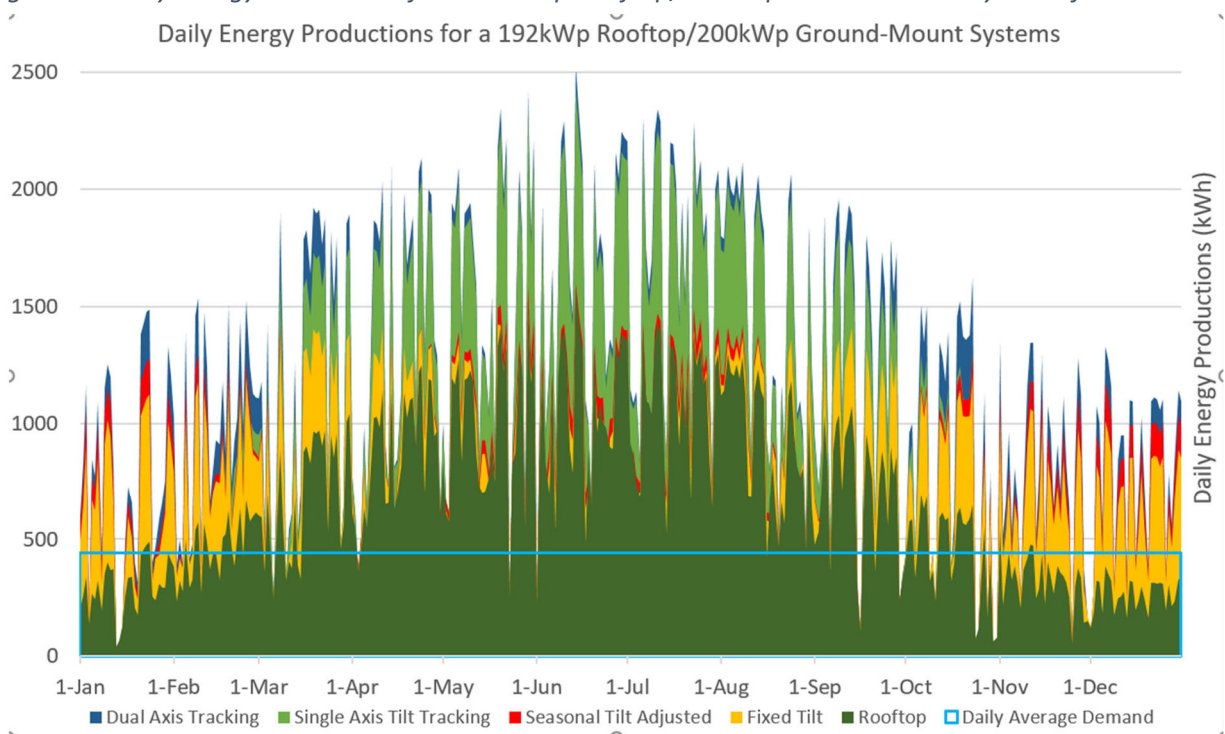
From the simulation results for shading analysis, the maximum shading losses for rooftop system was found to be <1 percent, whereas for the ground mount system, both near-shading (row-to-row shading) and far shadings are zero due to adequate spacing between panel rows and absence of any obstructions in farther proximities to the site location.

## Annual Energy Production for Different Design Considerations

PVsyst simulation was then used to generate the AEP estimates for a TMY for each of the different cases. Initial results were compared for rooftop vs ground-mount options which showed a significant increase in AEP of 27 percent for the latter system configuration. This led us to stick with the ground-mount option, as not only did the configuration provide substantial growth in AEP, but also was a superior option when taking into account other secondary factors such as mounting complications, risk of high wind during winter on rooftop mounting, the roof load bearing capacity, and overall higher cost associated with rooftop mounting in comparison to a ground-mount option.

After finalizing on a ground-mount configuration, other simulations were run for different optimization cases in terms of module mounting structure and type of PV modules used. The simulated AEP results for bifacial panel option showed an increase in AEP of mere 1.7 percent. Although bifacials can provide a more cost-effective benefits above latitudes of 40°<sup>12</sup>, the proposed plant site is situated at a latitude of 46°, so perhaps this is the reason for an insignificant increase in yield. Furthermore, based on the estimates from PVsyst, AEP increases for different panel mounting systems showed that compared to the fixed tilt (base case), a seasonal tilt adjusted system provided an increase of 4 percent, single axis tilt tracking with an increase in 25 percent, and dual axis tracking with an increase of 40 percent. However, it was also important to deep dive into these figures at a more granular level to be able to identify the best mounting configuration for the Producer Partnership. A daily production curve for all cases used in comparative simulation cases are presented in the figure below modelled over an entire TMY.

Figure 13: Daily Energy Productions for a 192kWp Rooftop/200kWp Ground-Mount Systems for a TMY



<sup>12</sup> Carlos D. Rodríguez-Gallegos, Monika Bieri, Oktoviano Gandhi, Jai Prakash Singh, Thomas Reindl, S.K. Panda, "Monofacial vs bifacial Si-based PV modules: Which one is more cost-effective?", Solar Energy, Volume 176, 2018, Pages 412-438, <https://doi.org/10.1016/j.solener.2018.10.012>.

The daily productions graph shows significant variance in terms of monthly average electricity productions. For the rooftop system configuration, the daily productions are significantly compromised across months extending from fall to spring (Oct-Apr); for summer months the productions from rooftop system are comparable to a fixed-tilt ground-mount system. Number of days with unmet demand (average daily demand highlighted by the blue straight line) is suggestively more for a rooftop configuration, whereas with a fixed tilt ground mount system the generation always peaks over the average daily demand when the daily available solar resource is above critically low irradiance level. Furthermore, the variance metric in terms of average monthly productions is lowered by 46 percent with a fixed-tilt ground mount system as compared to a rooftop mount. When the panels are oriented at the optimum tilt angle and azimuth degree, then the system is able to optimally capture more of the winter solstice; this is largely absent in a E-W configured system which is not able to effectively work during winter season. This is the effect of solar geometry and the daily solar path which varies according to season and location. Generally, the summer solstice occurs when the sun height is at it's maximum; the *solar declination* which is the angle between the direction of the center of the solar disk measured from Earth's center and the equatorial plane is at its highest<sup>13</sup>. Therefore, both rooftop and ground-mount solar are able to capture maximum solar irradiance at a greater extent during peak sun hours, however, during the winter solstice, as solar declination is at its lowest therefore, without an optimum panel mount configuration, the system is not able to capture maximum daily irradiance as is the case for a E-W rooftop racking system.

*Table 1: Increase in AEP for different Upgradation Options and System Configurations*

Base Case	Upgraded Options	Increase in AEP
Rooftop	Fixed Tilt	27%
Fixed Tilt	Seasonal Tilt Adjusted	4%
Fixed Tilt	Single Axis Tilt Tracking	25%
Fixed Tilt	Dual Axis Tracking	40%

The simulation results for different panel mounting configurations also shows a seasonally varying AEP increment percentage. Both single axis tilt tracking and dual axis tracking systems show equivalent increase in AEP during the summer month however, the latter has significant advantage for the same reason explained earlier in regards to solar declination—a dual axis can also optimally capture winter solstice that a two-dimensional single axis tilt tracking system is not able to do. However, the most surprising results are obtained for a seasonal tilt adjusted tracking system. Although it is a highly inefficient design option in terms of the total AEP productions increment, this system provides higher productions than single axis tilt tracking system during winter solstice. Therefore, a more rudimentary seasonal tilt system provides the lowest variation for monthly productions while also essentially meeting average daily

<sup>13</sup> John Page, Chapter II-1-A - The Role of Solar-Radiation Climatology in the Design of Photovoltaic Systems, Editor(s): Soteris A. Kalogirou, McEvoy's Handbook of Photovoltaics (Third Edition), Academic Press, 2018, Pages 601-670, ISBN 9780128099216, <https://doi.org/10.1016/B978-0-12-809921-6.00016-1>.

demand during critically low irradiance level. So, for current electricity requirement and general operation and maintenance considerations, a seasonal tilt mounting structure is more preferable.

### 4.3 Solar and Battery Technology Considerations

The solar panel make and model used in our study is the monocrystalline silicon SunPower SPR-E19-310-COM, with a maximum nominal power of 310 W, 19.02% efficiency, and a temperature coefficient of -1.197 Watts per degree Celsius. The battery make and model used in our study is a lithium nickel manganese cobalt oxide battery (NMC/Graphite). The Li-ion NMC/graphite battery was sized for between 400 – 1600 kWh of energy provision, depending on the size of the battery bank, for 8 hours of continuous operation. The battery technology we selected operates at 80.2% capacity at 0 degrees Celsius.

The temperature coefficient, efficiency, and capital cost were all important factors in our selection. Though we advise Mr. Pierson and TPP to house the batteries in an insulated building of some sort, the conditions in Livingston are such that resilience to windy conditions and cold temperatures is especially important for the selected panels and battery models. Temperature coefficients helped us to narrow our selection to three battery technologies and solar panel makes and models listed in the tables below.

To ultimately decide which solar panel models and battery technologies to use, we held all other factors in the SAM model run of a 200 kW solar plus 150 kW storage system *ceteris paribus* and compared capital cost, temperature coefficient, and technological efficiency. The results are depicted in the below tables. Note that the SAM model sources its database of solar module costs and battery costs from NREL’s Annual Technology Baseline.<sup>14</sup>

Table 2: *Ceteris Paribus Comparison of Solar Panel Makes and Models (Source: NREL Annual Technology Baseline)*

Make and Model	Capital Cost	Temperature Coefficient	Efficiency
SunPower SPR-E19-310-COM	\$663,750	-1.197 Watts per C	19.02%
LG Electronics Inc. 310N1K-G4	\$667,342	-1.116 Watts per C	19.52%
Auxin Solar AXN6M610T310	\$667,224	-1.196 Watts per C	19.05%
Sunergy California LLC ASUN310-60MM5	\$667,709	-1.248 Watts per C	19.16%
Jinko Solar Co. Ltd. JKMS310M-60L-EP	\$667,539	-1.266 Watts per C	19.51%

Table: *Ceteris Paribus Comparison of Battery Technologies (Source: NREL Annual Technology Baseline)*

Technology	Capital Cost	Capacity at 0 C	Capacity at -20 C
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<sup>14</sup> Feldman, D.; Ramasamy, V.; Fu, R.; Ramdas, A.; Desai, J.; Margolis, R. (2021). U.S. Solar Photovoltaic System and Energy Cost Benchmark: Q1 2020. NREL/PR-6A20-78882. ([PDF 4.6 MB](#))

Nickel Manganese Cobalt Oxide	\$666,843	80.2%	NA
Lithium Iron Phosphate	\$663,872	88.8%	72.3%
Flooded Lead Acid	\$663,783	72.1%	44.5%
Lithium Cobalt Oxide	\$663,750	88.8%	72.3%
Nickel Cobalt Aluminum Oxide	\$666,754	88.8%	72.3%

We selected the SunPower solar panel module due to its superior pricing and comparable efficiency and temperature degradation to other modules. SunPower modules are domestically manufactured in San Jose, California, a crucial factor as solar and battery supply has tightened in the past two years, and lead times are especially long for foreign-made products.

We also selected the lithium-ion battery using nickel manganese cobalt oxide technology for our study. Even though the performance at low temperatures and capital cost is higher than other battery technology candidates presented in the table, Li-ion NMC technology is the most commonly used technology in the world, and thus Mr. Pierson and TPP can expect a low-risk investment with both reliable specs and a shorter supply chain lead time than some alternative battery technologies. However, we present our analysis as a recommendation of sorts, and should TPP choose to instead invest in a newer, superior technology, we would support their efforts.

#### 4.4 Hybrid Solar plus Storage Sizing and Reliability

We used NREL’s SAM model to calculate the upfront capital cost and reliability for various combinations of solar and storage. We calibrated for off-grid solar (see Appendix 6 for the methodology to calibrate SAM to model TPP’s particular system.) We iterated nine different permutations of solar-plus-storage sizing for TPP’s daily energy demand. We began by adding 200 kW of storage to the 200 kWp optimum solar capacity generated by SAM (see: Section 4.2, “Total Installed Capacity”) Each model run was standardized in terms of solar technology used. (See Section 4.3, “Solar and Battery Technology Considerations” for a comparison of different makes and models of solar panels and battery technologies.)

We assessed the permutations of solar-plus-storage sizing along two factors: 1) total installed capital cost, in \$ and 2) reliability, in terms of unmet load (kW) at a given time step in a year. The SAM model generated 25-year cash flow models based on the inputs specifically tailored to an off-grid, small commercial operation like TPP, including module and battery system specifications, daily demand profile, and grid interconnection (in this case, lack thereof.)

We also imported weather data for a typical meteorological year (TMY) in Livingston, Montana to capture a reasonable profile of temperature and solar installation on an hourly basis over the course of a year. The system performance, in combination with the TMY data, allowed us to visualize at what hours the solar-plus-storage system would fail to meet the energy demands of TPP’s meat processing facility. In this case, TPP would presumably turn to the natural gas generator to meet instantaneous demand. SAM output took the form of a graph plotting energy demand over time overlaid with unmet load (kW) over 8,760 time steps.

A summary of the sensitivity analysis we performed on our nine selected permutations and their capital cost and reliability can be found in the below table. For clarity, we ranked reliability on a scale of 1-5, with a score of 5 representing a solar-plus-storage system that can meet energy demands round-the-clock during a typical meteorological year.

Table 3: Solar-Plus-Storage Sizing Options

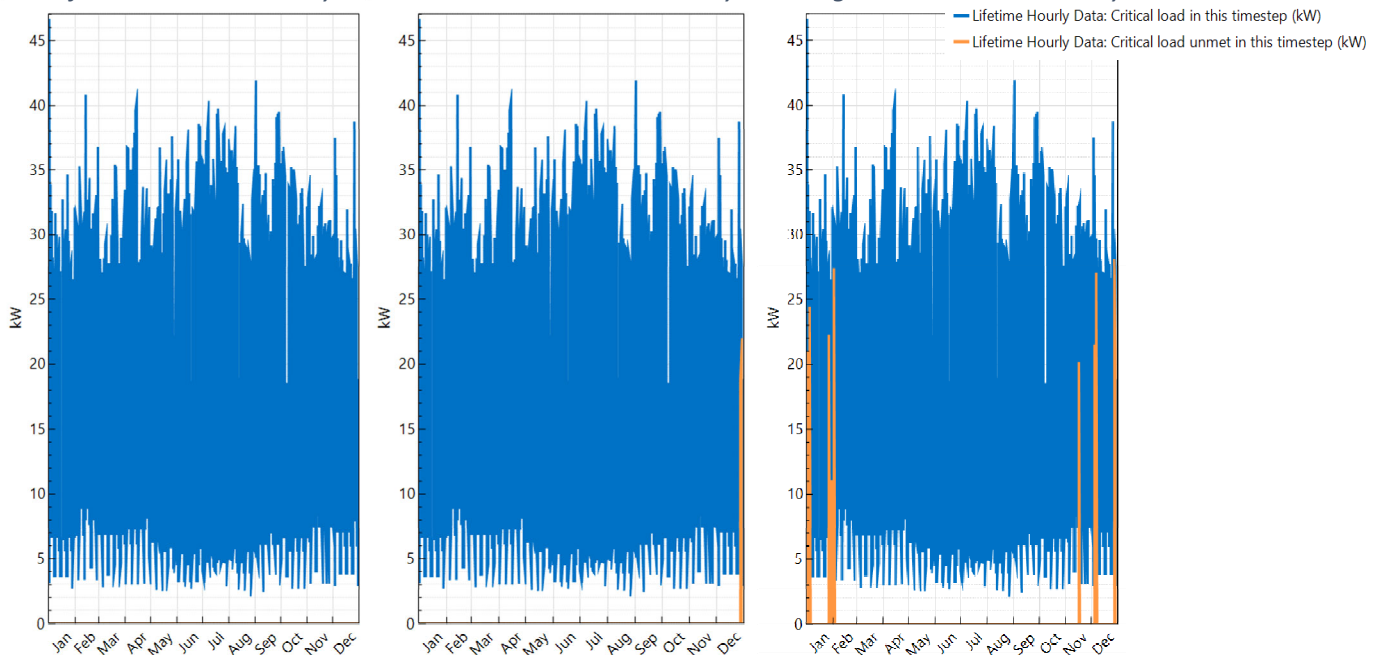
Solar size	Storage size	Storage duration	Capital Cost	Reliability
200 kW	200 kW	8h	\$774,091	5
150 kW	200 kW	8h	\$684,509	4
200 kW	150 kW	8h	\$666,843	4.5
120 kW	200 kW	8h	\$633,319	1.75
150 kW	150 kW	8h	\$577,261	3
120 kW	150 kW	8h	\$526,072	1.5
120 kW	120 kW	8h	\$462,152	1.5
200 kW	50 kW	8h	\$452,777	1.25
120 kW	50 kW	8h	\$312,006	1

Please see Appendix 5 (an .xlsx file titled “Appendix 5\_Solar plus Storage Cash Flows and Unmet Load\_Yale x TPP”) for detailed, year-by-year cash flow and hour-by-hour unmet load analyses.

The first option, 200 kW solar plus 200 kW storage, meets energy demand round-the-clock during a TMY. Of course, in an atypical meteorological event, even the 200-200 system might fail. The critical load (blue) and output load unmet (orange) for the 200-200 system are depicted in the below figure.

Figure 14: SAM Output superimposing critical load unmet on total critical load.

Left: 200 kW - 200 kW system. Center: 200 kW – 150 kW system. Right: 150 kW – 150 kW system.



Notably, for a nearly \$100,000 reduction in capital cost, a 200 kW solar plus 150 kW battery storage system would only fail to meet critical load during a few timesteps in December, when relatively weak solar resource and low temperatures fail to meet TPP's constant demand.

For a nearly \$100,000 reduction further in capital cost, a 150 kW solar plus 150 kW battery storage system fails to meet critical load during timesteps in the winter months only. Please see Section 5 for cost analysis of a solar-plus-wind-plus-storage system that supplements this 150-150 system with relatively strong wind resource in winter months.

Please see Appendix 3 for unmet load graphs for the other six solar-plus-storage sizing permutations.

## 5. Hybrid Solar-Wind-Storage System Outlook

### 5.1 Methodology

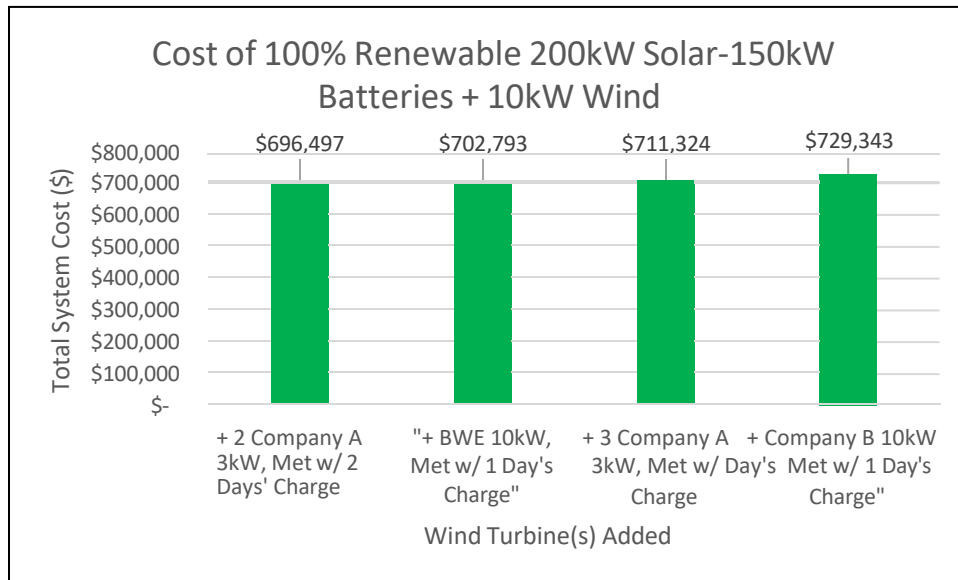
In order to approximate an integrated wind-and-solar model without advanced software, we isolated the days and hours from the Solar + Storage model when energy demand was not met into sets discrete hourly data, assuming that the kW deficit listed persisted over the whole hour (a conservative estimate), paired this with the 10-year average wind speed at those given hours of deficit, and used our derived speed vs. energy equations to calculate energy produced by several small turbine options over said hours. We then asked:

- 1) Within financial reason, which of our small & medium turbine options can meet this demand by simply running at the hours of S&S unmet demand?
- 2) If none can completely cover the deficit during the hours themselves within financial reason, how much time prior to the onset of the deficit would the turbines need to charge the batteries in order to supply the needed energy (ie. if a few hours, 1, or 2 days of charge is needed).
- 3) If that combined wind & reduced solar/battery combination is financially superior based on total system cost to the equivalently reliable and renewable no-wind S+S scenario.

### 5.2 Results

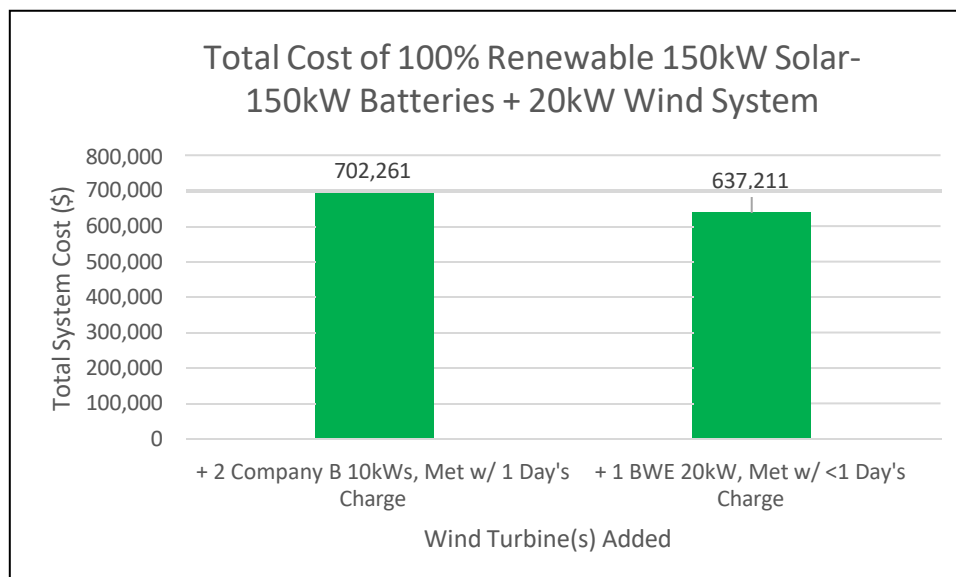
Perfect reliability with Solar + Storage alone costs \$774,091. By comparison, we can get equivalently perfect reliability (based off a "typical" solar year and a 10-year average wind year) by simply adding 3 Company A 3kW turbines or 1 Company B 80-ft SSL kW (which is not even our best 10kW turbine option) to a 200-150 S+S setup for a total cost of \$700,000-\$730,000. 2 Company A 3 kW turbines, as seen below, is technically the cheapest of the options below to achieve this, but considering the need for 2-day charge time with such a setup and the general unpredictability of weather, we would suggest for this setup, in order of preference: 1 BWE 10kW (if a 80-100 ft tower can indeed be supplemented), 1 Company B 10kW, or 3 Company A 3kW turbines.

Figure 15: 200-150-10 Solar-Storage-Wind Hybrid System Cost, with Various Turbine Options



The savings get even better, however, when we replace a further 50kW of solar and 50kW of batteries with just 20kW of wind. By adding just 20kW of wind to our \$577,261 150-150 S+S model, we transform a moderately unreliable system into a perfectly reliable system with a total price tag of \$637,211. For either supplemental application, we highly recommend the variable pitch options we have isolated (the BWE 20kW) not only for cost, but because of the ability to vary the blade pitch to meet the high speeds observed in the winter (the very time the supplement is needed). At our modeled time of greatest solar deficit (early December), the variable pitch capability of these turbines allows them to produce 26% more energy than an equivalent capacity of our non-variable pitch turbine option (2 Company B 10kW). The BWE 20kW would actually cover 82% of that time of greatest deficit just *during that largest deficit time period*, and only needs to have contributed to a few hours' worth of battery charge to completely cover said deficit.

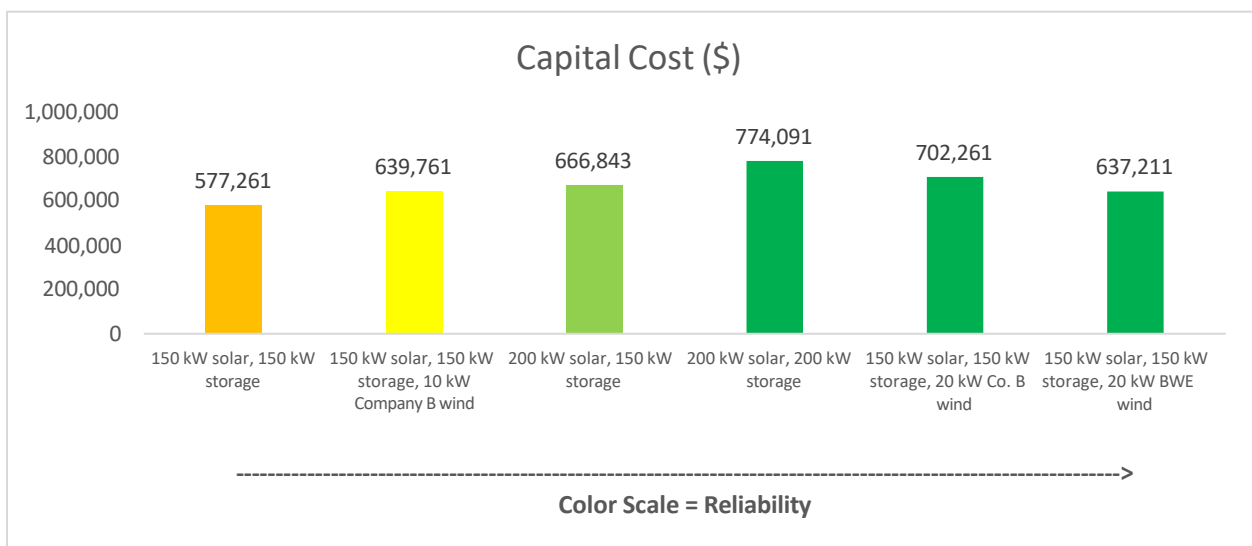
Figure 16: 150-150-20 Solar-Storage-Wind Hybrid System Cost, with Two Turbine Options



### 5.3 Key Findings

Based on our optimization of capital cost and reliability, we find that our most cost-effective system that can maintain “perfect” reliability (i.e., no dependence on the natural gas generator for backup) is the hybrid 150 kW solar – 150 storage – 20kW wind system. However, we recognize that perfect reliability may not exist due to atypical weather events that could exceed the severity of measurements contained in the TMY data. For that reason, we strongly recommend maintaining the natural gas generator as a backup. In that case, simple, low-cost options such as the solar-plus-storage 200 kW solar plus 150 kW battery storage system would also suffice.

Figure 17: Capital cost and reliability comparison of best S+S and S+S+W hybrid system options



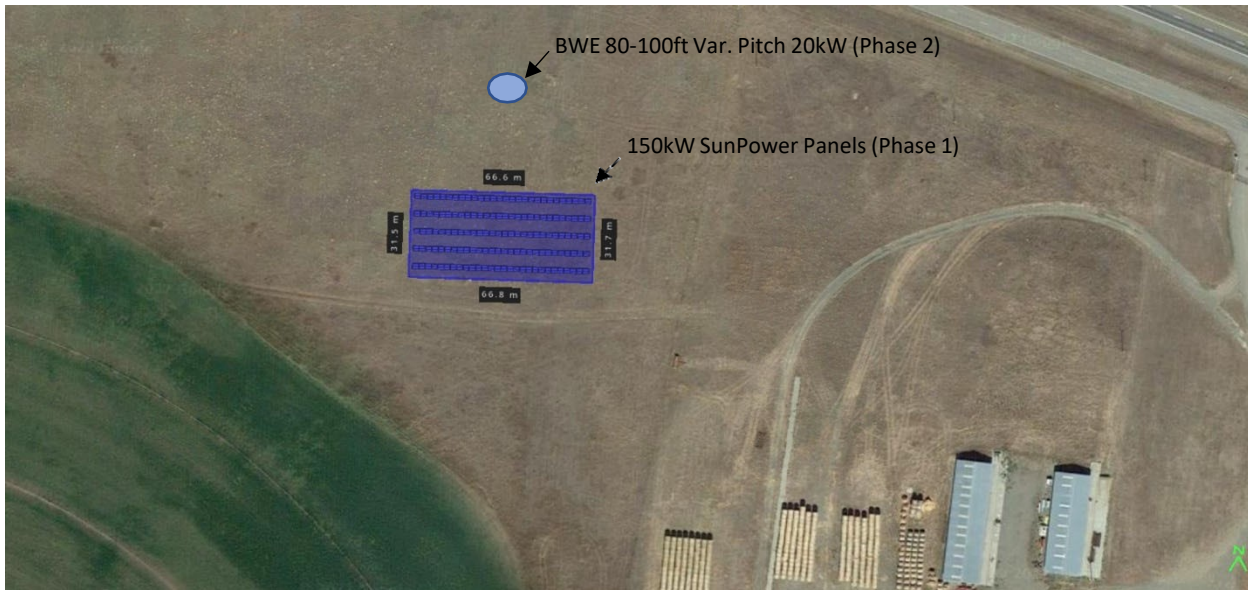
A good plan for moving forward while minimizing risk is to:

Phase 1: Build out the \$577,261 150-150 S+S system, using SunPower panels and Nuvation batteries, accepting generator reliance for a few winter days each winter.

Phase 2: When comfortable with this setup, add one \$59,950 20kW BWE Variable Pitch Turbine (with 80-100 ft tower) to the setup to achieve 100% renewable energy.

Phase 3: Once system reliability is proven (and ONLY once system reliability is proven) selling the natural gas generator for \$149,900.

Figure 18: Hybrid S-S-W 150-150-20 Setup Visualization: Total System Cost \$637,211



## 6. SCC and Emissions Analysis

The Social Cost of Carbon can be a useful measure for understanding the value of changes made according to policy decisions. In TPP’s particular case, we based our loose calculations on the EPA’s 2025 guidelines and supplemented those with an assumption of a 20-year lifetime use of a natural gas generator. Using discount rates of 5%, 3%, 2.50%, and 3% (High Impact and 95<sup>th</sup> percentile), these were our results:

	5.00%	3.00%	2.50%	3% (High Impact)
\$	9,801.32	\$ 31,527.58	\$ 45,902.85	\$ 94,909.45

To explain, given the provided discount rates, these would be the total material costs of the carbon produced over 20 years given a natural gas generator. That is, if TPP denied our proposal or if we had not provided a comprehensive plan, and “business as usual” was allowed to take place – these would be the amounts in USD that the EPA has determined matches the carbon emissions of the processing plant. Certainly, these are concerning figures for one plant and their usefulness can be assessed in the comparison of plan-to-plan and policy measure to measure.

Looking at the environmental impact, we also calculated the estimated CO<sub>2</sub>e emissions saving with our hybrid generation plan that includes 14 days of low natural gas usage of approximately 1,362 kWh of natural gas per day. This savings was calculated by subtracting the 14 days of low natural gas usage from the business-as-usual scenario where TPP would be using the natural gas generator at all

times. This was then multiplied with the 2021 UK DEFRA emissions factor for kWh of natural gas to get the annual CO<sub>2</sub>e savings. We then multiplied this by a 20 year time period to get the 20 year emissions savings. We were able to determine an annual CO<sub>2</sub>e savings of 28,800.83 tCO<sub>2</sub>e.

<b>Annual kWh Demand</b>			
<b>Hybrid generation plan</b>	19068		
<b>BAU</b>	160965		
<b>Emission factor for Natural Gas</b>			
UK DEFRA (2021)	kWH (Net CV)	to	kg CO <sub>2</sub> e
	1	to	0.20297
<b>Total Emissions</b>			
<b>BAU</b>	32671.067	kg CO <sub>2</sub> e/year	
	653421.32	metric tons CO <sub>2</sub> e/20 years	
<b>Hybrid generation plan</b>	3870.23	kg CO <sub>2</sub> e/year	
	77.4	metric tons CO <sub>2</sub> e/20 years	
<b>Total Annual tCO<sub>2</sub>e Savings</b>	28800.83		
<b>Total 20 year tCO<sub>2</sub>e Savings</b>	653343.92		

## 7. Additional Financial Considerations

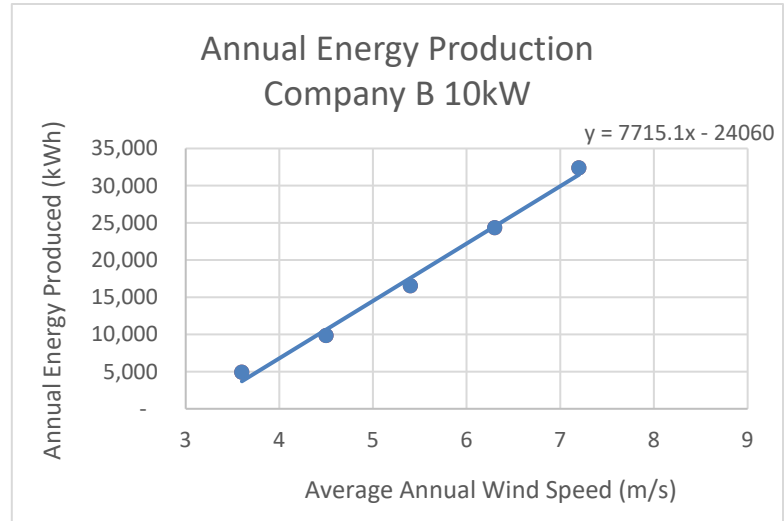
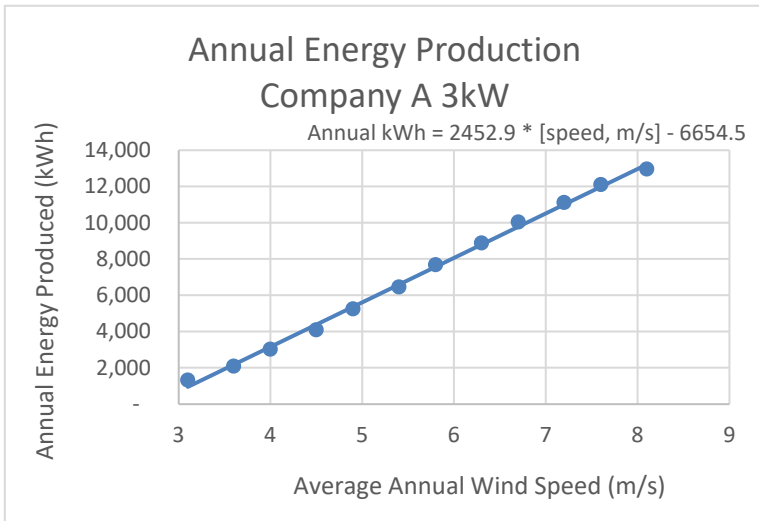
Beyond modeling the energy and storage for the processing plant, we sought out potential funding opportunities to cover the cost of a renewable energy system, including state and national funding. After chats with the USDA, TPP is not able to qualify for any USDA grants and low interest loan options under their Rural Energy for America Program as TPP is a non-profit and not a qualifying small business. This also means that TPP is unable to qualify for any investment tax or production tax credits as TPP does not get taxed as a non-profit. The only available funding opportunity is at the state level with Montana’s Alternative Energy Revolving Loan Program<sup>15</sup>. This program provides a low-interest loan at 3.0% to 3.40% APR to be given to non-profits and other qualifying organizations. The maximum loan amount is \$40,000 and the maximum loan term is 10 years. Overall, additional funding opportunities are limited due to TPP’s non-profit designation, a seeming loophole in many funding programs due to TPP’s unique mission as a meat processing donation non-profit.

<sup>15</sup> <https://deq.mt.gov/energy/Programs/AERLP>

Because under this plan we expect to meet projected energy demand based solely off utilization of the Northwest portion of the subject property, the Southeast plateau remains free. Given the cost-competitive (if not in the end victorious) position of the Company D turbine placed merely 100 ft off the ground, multiple 100 kW or even 1 MW turbines located on the raised plateau to the Southeast could provide an overwhelming amount of energy to the expanding business at low cost, and in an eventually grid-tied future, the excess could be sold back to the grid to fund the entire non-profit operation and much more. In order to set up for this future scenario, we recommend the immediate purchase of a portable solar-powered SODAR or met tower wind speed measurement system. The best option would be to purchase a used portable Triton Sodar system for around \$15,000, and pay an additional data activation fee of \$10,000. An NRG met tower, comparatively, would cost in total (including installation) about \$55,000.

## 8. Appendices

### Appendix 1. Particular Manufacturer Wind Speed vs. Annual Energy Production Graphs



\*BWE and Company D Power Rating Curves redacted as potentially proprietary non-public information.

## Appendix 2. Historical Monthly Wind Speed Graphs

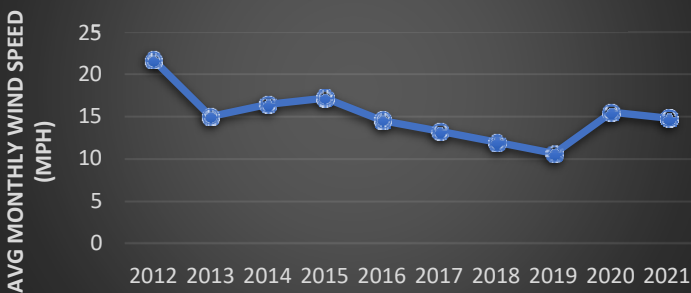
### January: Historical Wind Speeds



### February: Historical Wind Speeds



### March: Historical Wind Speeds



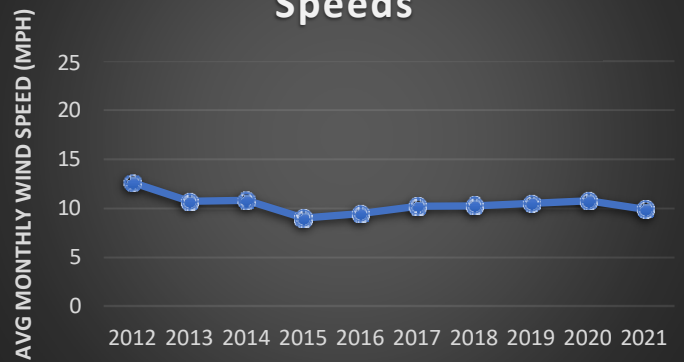
### April: Historical Wind Speeds



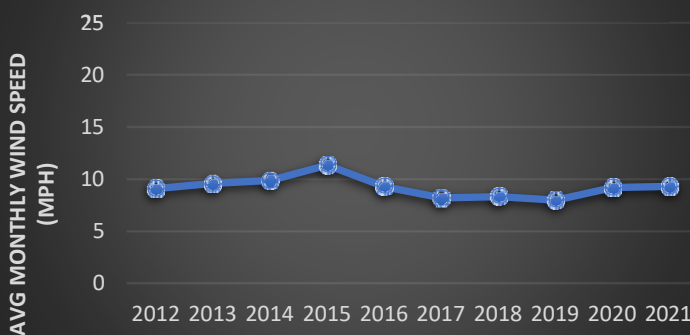
### May: Historical Wind Speeds



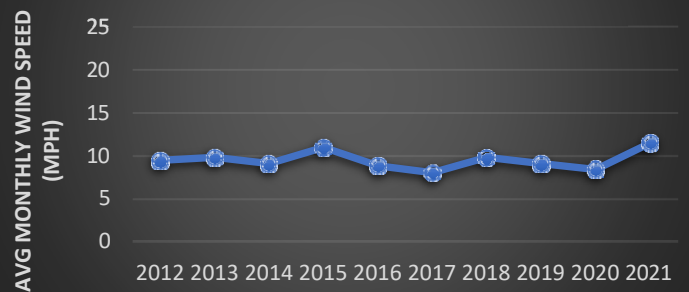
### June: Historical Wind Speeds



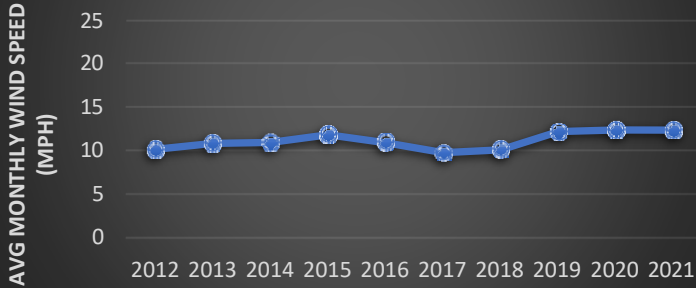
### July: Historical Wind Speeds



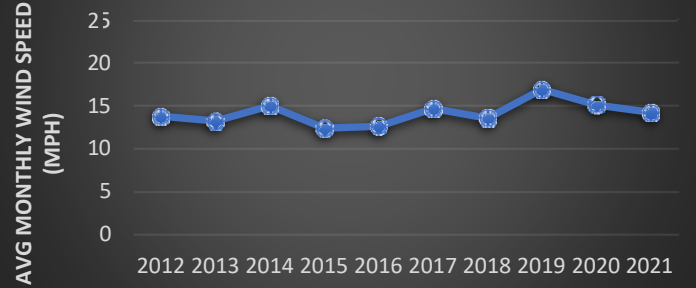
### August: Historical Wind Speeds



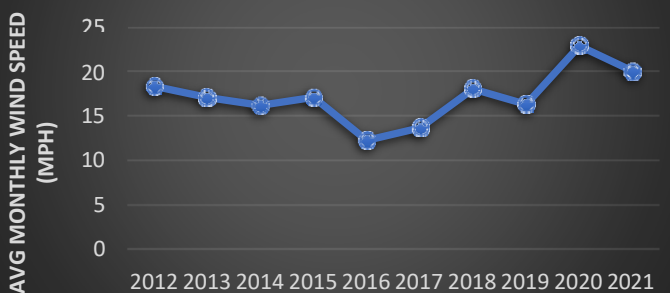
### September: Historical Wind Speeds



### October: Historical Wind Speeds



### November: Historical Wind Speeds

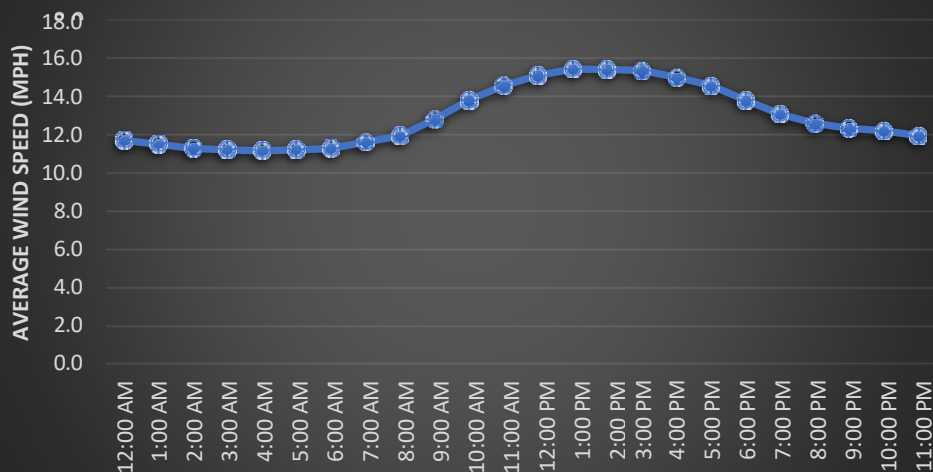


### December: Historical Wind Speeds



### Appendix 3. Typical Diurnal Variation at 33 ft

#### Diurnal Cycle of Montana Wind (mph)



## Appendix 4. Space Allocation for Company A & Company B (near) 100% Renewable Wind Energy Only Setup

Company B 10kW Turbine System



Company A 3kW Turbine System



The left-hand image below depicts the occupied space for 16 Company B 10kW turbines. The right-hand image depicts the occupied space for 36 Company A 3kW turbines. The actual amounts needed for near-100% wind energy are even greater - 18 and 47 respectively – so neither of these are viable options for this space.

## Appendix 5. Solar + Storage Cash Flows and Unmet Load

[Redacted]

## Appendix 6. How to calibrate the SAM model for off-grid solar

[Redacted]