Energetic Comparison of Vertical Bifacial to Tilted Monofacial Solar

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***Abstract*—In this article, a vertical bifacial + reflector configuration is presented as a candidate for solar canals and other applications that allow dual use of the land. Modeling with weather data from Merced, CA shows output to be competitive with fixed 20° tilt systems, with south-facing vertical orientation showing 117% and 87% of annual output of south-facing 20° systems with and without a reflector, respectively. Repetition with weather data from Houston, Denver, and Miami produces similar results, with values ranging from 112%–121% and 82%–94%, which serve as conservative estimates due to lack of modeled soiling on tilted systems in the latter comparison. South-facing vertical orientations have better performance in nonsummer months relative to other systems, resulting in a flatter seasonal curve, with useful implications for load balancing and energy storage. East- and west-facing vertical orientations outperform their fixed tilt defaults, even without a reflector, and tolerate higher dc/ac inverter ratios than similar south-facing vertical orientations before appreciable clipping effects are seen.**

***Index Terms*—Bifacial, solar generation, solar panels, vertical panels.**

I. Introduction

BIFACIAL panels have traditionally been used in standard inclined systems of ground or roof mounting to improve performance by absorbing light reflected off the surface behind the panel, though increasing study has been done in relation to bifacial panels in a vertical arrangement. Modeling by Guo et al. [1] found that a single vertical bifacial panel, where self-shading is not a concern, will produce more than a single monofacial panel (set at tilt equal to latitude) anywhere in the world with an albedo greater than 0.35. Regarding the prospect of vertical bifacial solar farms, Khan et al. [2] found them capable of generating 10%–20% more energy than a traditional monofacial farm for a practical row spacing of 2 m corresponding to 1.2-m high panels. Further studies have examined the impact of horizontal reflectors in the form of cement and white gravel beds [3] and ground sculpting between panels [4] to increase output of such farms.

Integrating solar panels into locations that are used for other purposes is attracting interest as solar is becoming ubiquitous. These include integration into the outer walls of buildings [5] and incorporation into agrivoltaic farm systems [6], where their extremely low soiling rates compared to inclined systems are of particular benefit, as is the shading offered to sensitive crops. This low soiling of vertical systems also applies to snow loading, and when considered together with the strong dependance on albedo, vertical bifacial panels are particularly attractive for northern climates, such as Alaska, where a combination of east–west oriented vertical panels and south-facing tilted bifacial panels are considered to smooth out daily and annual production profiles [7]. In addition to buildings and agrivoltaic farms, other dual land use applications for bifacial panels include implementation as noise barriers along highways. Uden, in The Netherlands, hosts a 400-m-long and 5-m-high solar noise barrier made of bifacial panels at 80° tilt, for which Villa and De Jong [8] studied the performance impact of installing concrete tiles on the backslope as a reflector.

Of interest to this article is the integration of solar panels into waterways to form “solar canals.” Solar canals are similar in concept to “floating PV,” in which solar panels are attached to floating platforms placed over reservoirs, and share many of the same benefits, such as dual land use reducing the need to set aside large areas of land for solar farms, reduction of evaporative losses and algae growth due to shading of the water, and improved PV performance due to underside cooling [9]. The concept has seen a rise in popularity in recent years, with multiple studies examining the production potential of both floating PV and solar canal implementation [10], [11], [12], [13], [14], [15], [16] and the impact on evaporative losses and water quality in arid regions [17], [18], as well as performance assessment and degradation studies of different PV technologies when applied to overcanal use in more humid environments [19], [20], [21].

A 2021 study by McKuin et al. [22] found that building solar panels overtop of existing canals in California could reduce annual evaporation by an average of 39 ± 12 thousand m^3 per kilometer. With the additional benefits of aquatic weed mitigation, the financial benefits of overcanal solar were found to exceed the cost of necessary cable-support systems and the net present value of overcanal solar was found to exceed conventional overground solar by 20% to 50%.

In contrast to installation over the canal via trusses or suspension, we propose a system design in which a single row of vertical bifacial panels (VBF) is installed along one side of the canal, facing perpendicular to waterflow, while a highly reflective cover is stretched across to the opposite bank, either hanging freely while tied to a pole, or attached to a lightweight frame that

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spans the canal. The reflective cover preserves the evaporative loss reduction and aquatic weed mitigation benefits of overcanal systems while increasing performance of the panels, and could be detached from the opposite side for easier access for any required maintenance. The material of the cover would need to be highly reflective, light weight, waterproof, and durable under wind and heavy sun exposure. Candidate materials currently include aluminized mylar film, such as that used in indoor grow rooms, heavy duty thermal aluminum insulation used in weatherproofing, and nylon backed mylar used in some car sunshades. Such a system would be suited to narrow canals, where the width is comparable to the height of the panel, as reflector material further from the panel contributes progressively less reflected light to the vertical panels. Wider canals also allow for overcanal designs to fit more panels from bank to bank per canal length, increasing their productive advantage over the vertical system, which is restricted to a single row.

To assess the viability of such a system, we used weather and irradiance data for a location near UC Merced to conduct preliminary modeling of the output of hypothetical vertical bifacial panels, both with and without a reflector present, as well as for monofacial panels at a 20° tilt, at multiple orientations. The 20° monofacial panels are representative of more traditional ground-based solar installations and are used here to represent the probable overcanal system designs for comparison. Several soiling studies were consulted [23], [24], [25] in order to establish a constant soiling rate for the Central Valley and used in conjunction with Bhaduri's vertical soiling study [26] to apply a dynamic soiling model to all panels. After comparing the annual and monthly totals of each configuration, we repeated the comparison with irradiance data from different geographic locations and examined the effect of varying orientation and tilt on the relative performance of the two systems.

II. Experiment Design and Methodology

The PVlib python package [27] was used to simulate multiple 5000-W solar arrays, mounted both vertically and at a 20° incline, in multiple orientations. 2019 half-hour weather data from the National Solar Radiation Database [28] were used to simulate output of each panel over the course of a year for a location near UC Merced (latitude = 37.365, longitude = –120.422). Said data included wind speed, temperature, direct normal irradiance, and both diffuse and global horizontal irradiance precalculated from direct normal values. These values were provided as a weather file to PVlib's ModelChain object with the following default settings.

clearsky_model: ineichen [29], [30]
transposition_model: haydavies [31]
solar_position_method: nrel_numpy [32]
airmass_model: kastenyoung1989 [33]
dc_model: pvwatts_dc [34]
ac_model: pvwatts_inverter [34]
aoi_model: physical_aoi_loss [35]
spectral_model: no_spectral_loss
temperature_model: sapm_temp [36]
losses_model: no_extra_losses (selected in order to introduce custom dynamic soiling model later)

The bifacial panels were modeled by adding the dc output of opposite facing vertical panels as input into an inverter, with the output of one side multiplied by a 0.9 "bifaciality factor." According to documentation on the PVlib website, calculations for ground diffuse irradiance are sourced from Loutzenhiser [37] and depend on the specific sky diffuse model chosen. In this case (Hay–Davies), the ground diffuse irradiance is given by the last term in equation 7. The presence of a diffusely reflective cover was modeled by changing the ground albedo on one side from the default 0.25 to 0.9. Because this has the effect of treating the reflector as if it were simply a highly reflective patch of ground, this simplification for the model does not account for any variation in angle between array and reflector. Increasing the angle is likely to raise outputs above those shown here, up to some critical angle at which shading effects from the reflector will take over. Each array was assumed to be isolated without shading, as would be expected for a solar canal. Study of the effects of shade was outside of the scope of this study.

DC output values were initially calculated without losses in order to apply a dynamic soiling model. The PVlib package contains a built in Kimber soiling model based on Kimber et al. [38]. Daily soil level as total % power loss was calculated using daily soiling rates specific to the fixed tilt and vertical bifacial systems. The model's default rate of 0.15%/day was found to be appropriate for a 20° fixed tilt panel in the Central Valley, which prior literature suggests is typically 0.108%–0.157%/day [7], [8], [9]. To determine an appropriate rate for the vertical panels, the results of Bhaduri and Kottantharayil [26] were consulted, with the assumption that, though absolute soiling rates may differ between California and Mumbai, the ratio of vertical to 19° fixed tilt results should be similar for similar tilt angles. Applying that ratio to the value range listed earlier produced a range of 0.002%–0.01% /day, from which a value of 0.006%/day was chosen for the simulated vertical panels. 2019 Merced precipitation data from the California Irrigation Management Information System [39] were consulted to identify cleaning events that would reset soil levels. Though the Kimber model selects a default cleaning threshold of 6 mm of rain, Caron and Littmann [7] were able to obtain accurate modeling of their observed 25° tilt system, located in Stratford, with only a 1-mm threshold. With this in mind, the cleaning threshold was set to 1 mm with a 3 day grace period before soiling resumes again. Soiling losses were only applied to the panels and not the reflector, which the model treats as a horizontal patch of reflective ground as stated earlier.

Once daily soiling losses were calculated for each system, the values were entered into the built-in PVWatts loss tool [34] that combines various loss factors, such as soiling, wiring, connection mismatch, and light induced degradation, among others, into a single flat % power loss. The default parameters were used, with the exception of the soiling loss rates. The modeled values were used to calculate day-specific total losses. These losses were then applied to the daily dc output totals for each panel before being sent to the virtual inverter to produce daily ac totals, which were then summed to produce monthly and annual totals.

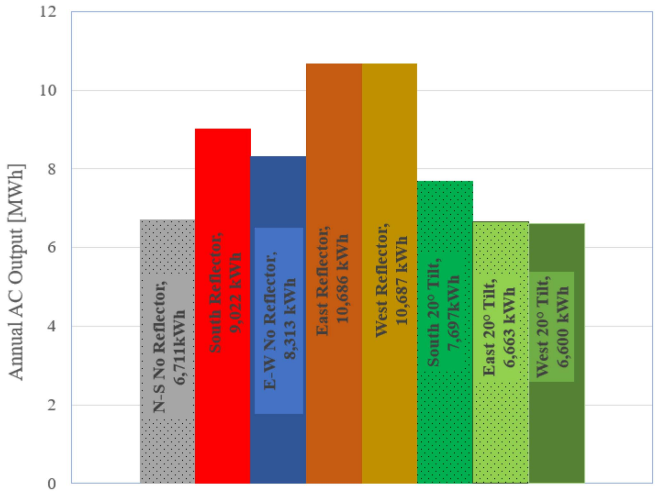

Fig. 1. Annual ac output for a vertical bifacial 5-kW array (bifaciality 0.9) in north–south and east–west orientation, with and without reflectors present, compared with fixed 20° tilt monofacial systems.

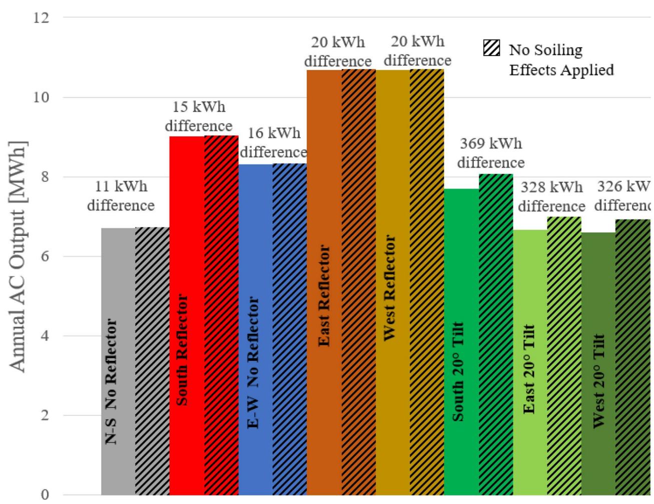

Fig. 2. Annual output as in Fig. 1, comparing values with and without soiling, all further figures use values with soiling.

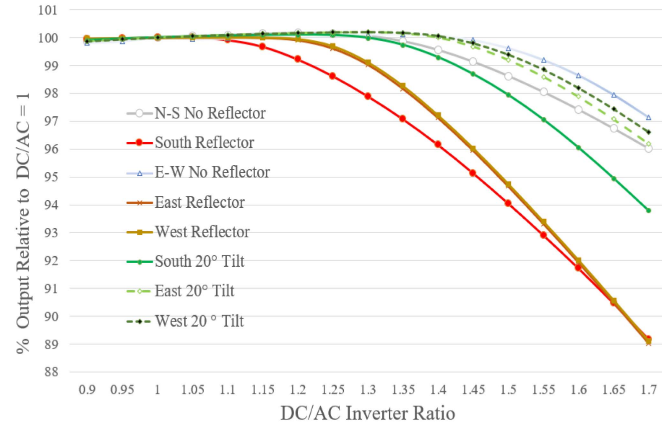

Fig. 3. Effect of different dc/ac inverter ratios for 5-kW dc systems, shown as % of values given in Fig. 1 where the default ratio is 1.

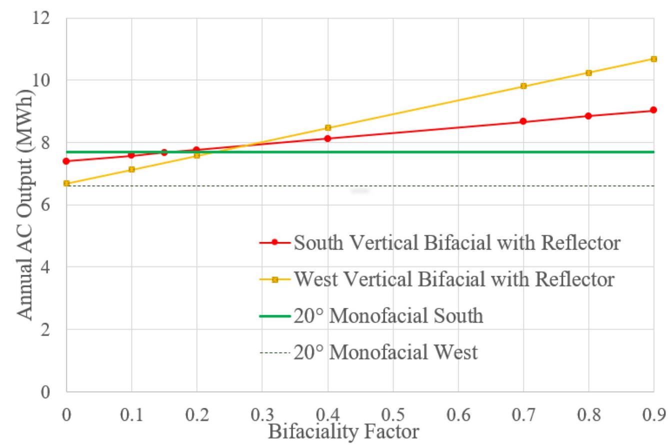

Fig. 4. Comparison of performance at lower bifaciality factors.

III. Results

Fig. 1 shows the total annual ac electricity output of each configuration at a default dc/ac inverter ratio of 1. Note that in the case of the bifacial panels, this does not mean entirely unclipped, as the ratio is based on the 5000-W rating of the array, and in some rare instances, the sum of the front and back generation may exceed 5000 W. These values include all losses and soiling effects.

As the specific soiling rates used are highly dependent on local conditions, Fig. 2 compares these results with those obtained by running the model with no soiling losses.

In present day systems, a dc/ac ratio > 1 is often used to reduce the cost of the inverter and other costs associated with the ac power rating (or, conversely, to enable the system to operate at a higher capacity factor). Fig. 3 shows the impact of varying dc/ac inverter ratios on the annual output as a % of the values given by Fig. 1. Values sometimes exceed 100% due to how inverter efficiency is modeled in the PVlib software, with efficiency dropping when dc input is farther from the rated input of the inverter. This results in lower rated inverters seeing slightly higher efficiencies during times of low irradiance.

As west and east vertical systems display a negligible difference in annual production (106 86 kWh versus 10 687 kWh, as shown in Fig 1), the following figure focus on the west-facing systems, as electrical demand is typically higher in the evenings. Fig. 4 shows the difference in annual output for south and west facing systems at bifaciality factors below the initial value of 0.9 used in Fig. 1.

Fig. 5 takes the annual values of the south and west facing systems from Fig. 1, and breaks them into monthly totals, showing seasonal behavior. It also includes monthly net demand (demand for electricity minus solar and wind generation) for California for that year, obtained from CAISO production and curtailment data for 2019.

Figs. 6 and 7 provide an hourly breakdown of the monthly production shown in Fig. 5 for June and December, in order to provide typical daily profile for summer and winter. Average hourly production values are generated by summing all production at a given hour within a month and dividing by the number of days in the month. For example, the value at hour 13 displays

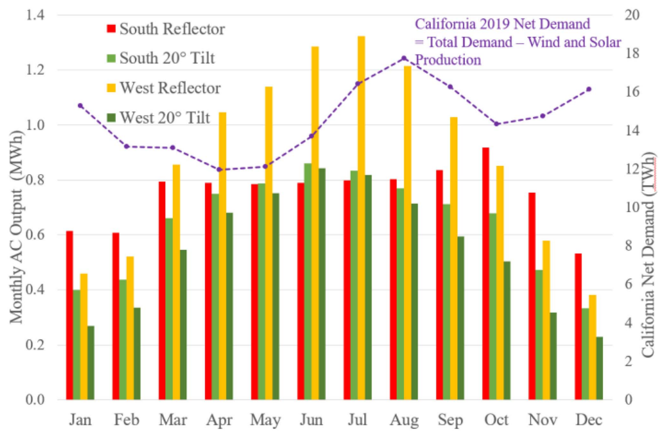

Fig. 5. Monthly total outputs of each system and comparison with California net demand for the same year.

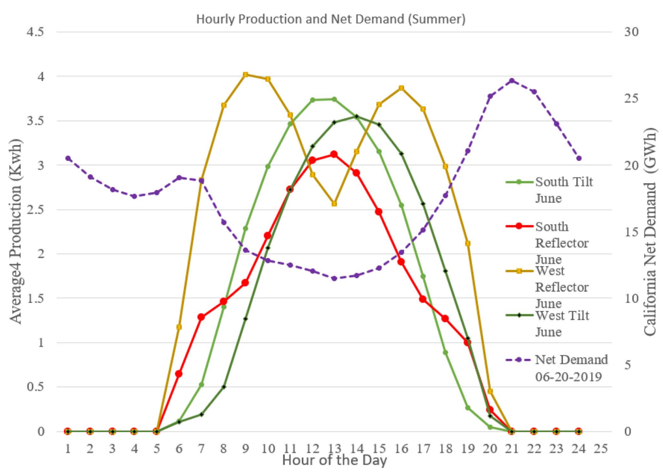

Fig. 6. Average production by hour (June) versus California net demand.

the average production at hour 13 for all days in the month. Included for comparison in each figure is the net demand curve for a sample day. In the case of Fig. 7, a day from January was used rather than December, due to a gap in CAISO's net demand data on their website.

Modeling was repeated using additional irradiance and temperature data for locations in Houston (latitude = 30.061, longitude = –95.528), Denver (latitude = 39.764, longitude = –104.855), and Miami (latitude = 25.782, longitude = –80.229). Soiling effects were not included in these runs, so further comparisons use the nonsoiling Merced results from Fig. 2. The following figures and tables compare the four locations in terms of "relative yield," which is the ratio of the output of the vertical bifacial panels to the output of the fixed tilt monofacial panels. Thus, a value of 1 corresponds to equal performance between the two systems, whereas a value of 1.5 would indicate a 50% increase in performance of the vertical bifacial system relative to the tilted monofacial. Table I lists the annual relative yields for each location, whereas Figs. 8 and 9 show the monthly relative yields for south and west facing systems, respectively, both with and without a reflector present. The default parameter of 0.25 for local albedo was left unaltered. Thus, locations with seasonal

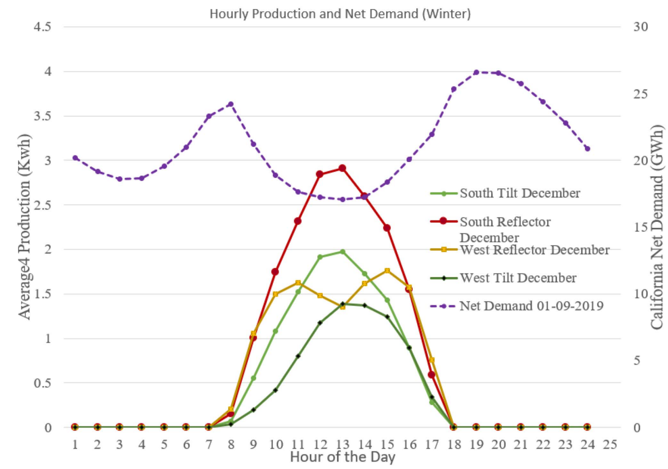

Fig. 7. Average production by hour (December) versus California net demand. Sample day for net demand taken from January due to data gap in December.

TABLE I
ANNUAL RELATIVE YIELDS

	Merced	Houston	Denver	Miami
South + Reflector	1.12	1.15	1.21	1.12
South No Reflector	0.83	0.85	0.94	0.82
West + Reflector	1.55	1.53	1.62	1.54
West No Reflector	1.20	1.19	1.27	1.19

Note: Vertical bifacial/20° fixed tilt monofacial.

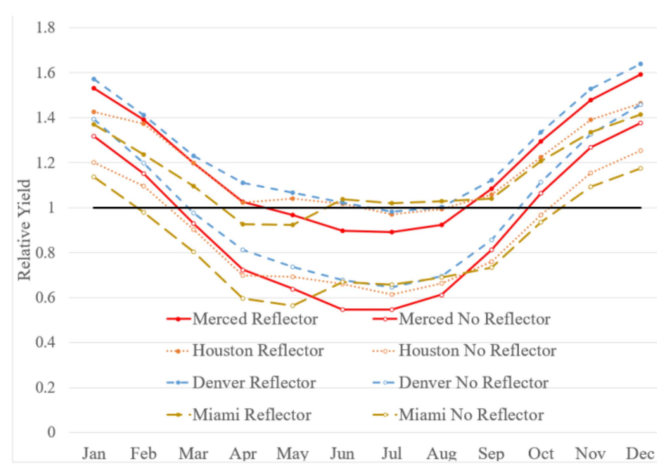

Fig. 8. Monthly relative yields for south-facing systems. Vertical bifacial/20° fixed tilt monofacial.

changes to albedo, such as from snowfall, may see higher relative yields than shown.

Real waterways, parking lots, and farmland do not always conform to strict north–south or east–west orientations, and standards for the optimal tilt of a fixed system may vary by local latitude and design constraints related to available space and

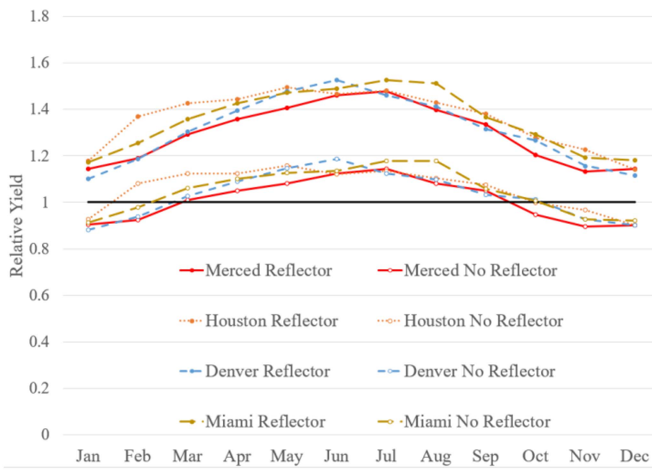

Fig. 9. Monthly relative yields for west-facing systems. Vertical bifacial/20° fixed tilt monofacial.

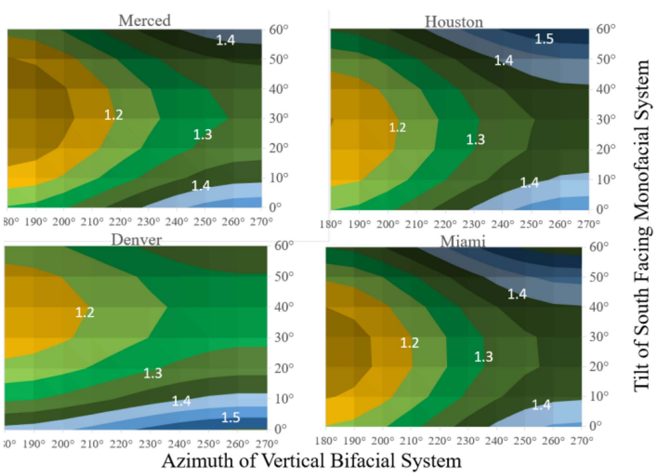

Fig. 10. Annual relative yields (vertical bifacial/ tilted monofacial) at varying tilt and orientation combinations.

self-shading effects. With this in mind, Fig. 10 was constructed to compare annual relative yields across various azimuths (180° = south, 270° = west) for a vertical bifacial system and tilt values for a monofacial stystem with the same power rating. The monofacial systems are assumed to be facing south, regardless of their tilt.

To more closely examine the advantage of each system in winter, Fig. 11 repeats the process above to show the relative yield for the 4 month period of November through February.

IV. Analysis of Results and Significance of Findings

With soiling effects ignored and without a reflector in place, a south-facing vertical bifacial system in central California produces 83% of the output of a similarly located south-facing 20° system of the same size. With the reflector added, it outperforms the 20° system by 12%. When typical soiling rates of the Central Valley are applied, these values climb to 87% and 17%, respectively. The east/west-facing vertical bifacial system outperforms an east/west-facing 20° system, both with and without a reflector

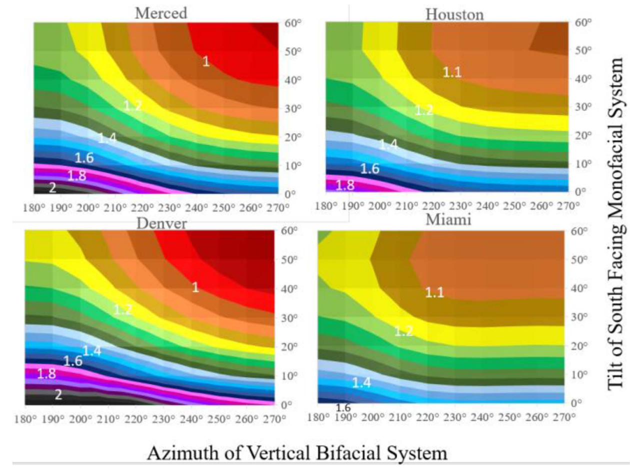

Fig. 11. Winter relative yields (November–February) at varying tilt and orientation combinations, similar to Fig. 10, but for the winter.

present. Whether the reflector is on the east or west side has negligible impact on the total output (about 1 kWh over the course of a year), though the west side is typically considered more desirable due to elevated evening demand for electricity.

Of particular interest is that south-facing vertical bifacial systems perform significantly better than 20° monofacial systems in nonsummer months, and outperform east/west-facing vertical panels during winter months, producing a much flatter production curve overall. While net monthly demand remains highest from July to September, net demand from November to January remains substantial due to the general lack of availability of both wind and solar resources during winter. Designs that can improve performance in winter months could be of significant utility for seasonal load management.

On a more diurnal scale, E-W facing VBF systems have great potential for shifting time of day production to better coincide with net demand (particularly in summer months), offsetting some of the requirement for same day storage to capture production from the midday peaks typical of other systems. Though their peak hours of production still fall short of overlapping peak net demand, they display a strong advantage over other configurations during those periods. At the same time, their higher overall production during summer months makes them an excellent complement to diurnal storage. However, their performance is sharply reduced in the winter, with no time-of-day advantage over south-facing VBF, as shown in Fig. 7. This supports the conclusion that south-facing VBF are best used for winter optimization, whereas E-W configurations are used to improve same day and day to day load balancing efforts.

Higher dc/ac inverter ratios allow for cost savings under conditions where the dc output of the panels rarely approaches their maximum rating. The east/west-facing 20° systems and reflector-less vertical bifacial systems show the highest tolerance for increased inverter ratios before appreciable clipping losses are seen on an annual scale. This is unsurprising when considering that an east/west-facing panel will spend less time receiving direct sunlight than a south-facing system and will have most of its output associated with a lower capacity. The addition of a reflector to the vertical bifacial systems dramatically lowers this tolerance for higher inverter ratios, indicating that in addition to raising the overall annual output (see Fig. 1), it also raises the peak output to the point that clipping losses become relevant comparatively sooner. The lower tolerance to clipping of reflector systems is unlikely to present a significant problem when considering the overall gains in total annual output. It is worth noting that the east and west reflector systems produce both higher annual totals a*nd* tolerate slightly higher inverter ratios than the south reflector system, the former crossing the 2% loss mark at a ratio of 1.35, whereas the latter does the same at 1.30. Though the choice of preferred orientation when deploying such a system is likely to be dictated by site conditions and the geography of the site, there may be reason to favor an east/west oriented site with all other considerations being equal, or even a slight rotation of the vertical panel and a diagonal installation relative to the reflector.

While a bifaciality factor of 0.9 or higher is possible with heterojunction with intrinsic thin layer technology, this tends to represent the higher end and more expensive premium panels, while 0.7 – 0.8 is more representative of panels typically found on the market. At a factor of 0.7, with soiling effects applied to all panels, a south-facing vertical system with a reflector still outperforms the 20° default by 12.5% (as opposed to the 17% mentioned above). The south-facing vertical panel continues to outperform the 20° default at a bifaciality as low as 0.17, whereas the west-facing system outperforms the west 20° default at all values, with a 1% advantage at 0 bifaciality (a vertically mounted monofacial panel in front of a reflector).

When expanding the modeling to include additional locations, similar seasonal behavior is seen, with west-facing vertical bifacial systems having the strongest advantage over tilted monofacial systems in the summer and dipping during shoulder months, while south-facing systems show the inverse. While the west-facing systems vary little between locations, south-facing systems have stronger differentiation, particularly in winter. When considering relative yield between vertical bifacial and tilted monofacial systems in terms of total annual production, Merced, Houston, and Miami show consistent results of 82% – 85% for a south-facing reflector-less system, and 112% – 115% for a system with a reflector (these serve as slightly conservative estimates as local soiling effects were not included, which would boost the relative performance of the vertical systems by several %, as shown in Fig. 2). Results for Denver are significantly higher at 94% and 121%, respectively, possibly a result of higher elevation and decreased air mass improving gains in morning and evening hours relative to other locations. These values should in fact be elevated further by the impact of snow loading on shallow angle panels as well as seasonal changes to local albedo from snowfall that should favor steeper tilts and narrow the gap in performance between vertical bifacials with and without reflectors. Though a vertical bifacial + reflector system would thrive in such a climate, it is unlikely that the primary benefits of canal shading, such as reduction of evaporative losses, would be as impactful as in warmer climates. The strong performance of the reflector-less systems plus the advantages in terms of snow loading suggest a range of possible applications, including along railways and highways, doubling as sound barriers, or along any other narrow, linear space.

The winter advantage of southward orientations is heavily dominated by the tilt angle of the monofacial system being compared against. A steep angled monofacial system would quickly reduce the winter advantage of a vertical bifacial system (as it becomes closer to vertical itself), in which case, the difference in performance is increasingly dominated by the bifaciality factor and the ground albedo.

V. Conclusion

Though no comparative economic or environmental analysis is performed, modeling shows a single line of vertically mounted bifacial panels paired with reflectors (or high albedo of the adjacent area) to be energetically competitive with monofacial systems mounted at a range of angles. The simplicity of the vertical construction and the possibility of using it as a sound barrier makes it especially appealing along highways. It may also be useful along canals that are fairly narrow, especially when its installation can be coupled with installation of a canal liner, avoiding the need for a separate retaining wall to support the vertical installation at the canal's edge. One of the primary benefits of a vertical system is the extremely low soiling rate compared to standard fixed tilt systems, which would be most valuable in locations with high soiling, such as areas of heavy agricultural or industrial activity. Thus, the introduction of low-cost bifacial solar modules has created an opportunity for a range of new applications. While one might naively assume that a vertical surface would not be viable for solar installations, the response of both sides of bifacial panels, especially coupled with nearby ground reflection, makes the vertical bifacial installation quite attractive. The advantages of such systems are strongest where available space is limited to a single long row. Applications that might include installation of multiple rows of vertical bifacial arrays need to consider row-to-row shading, an effect that was outside of the scope of this study.

Vertical bifacial systems, particularly those facing south, see increased advantage in winter months when solar resources are scarce. This flattening of seasonal behavior could be of significant benefit to load management efforts by reducing the need for additional seasonal storage when implemented as part of the wider power grid. The scale of this winter advantage is reduced when compared to monofacial systems at steeper tilts, in which case the impact of reflectance due to local albedo would become the increasingly dominant factor. Higher elevations may also increase this advantage due to reduced scattering of light from low angles. Combined with the resiliency against soiling and snow loading, this makes vertical bifacial panels a particularly attractive option for areas that see regular heavy snowfall. In particular, such systems oriented to be south-facing would be of great benefit to businesses or communities that see heavy load or seasonal tourism in the winter, such as a ski-resort.

As east-west-facing vertical bifacial systems outperform fixed monofacial 20°-tilt systems in terms of total yield, both with and without a reflector present, there is an attractive opportunity to pair them with energy storage. Such systems also tolerate slightly higher inverter ratios at low to moderate albedo conditions, resulting in cost savings. Higher albedo diminishes this benefit, but in return for much larger gains in total output. These are in addition to the benefits of power during common periods of peak demand. A business with high traffic during morning or evening hours, such as a diner catering to breakfast and dinner crowds, would benefit from an east-west-facing vertical bifacial system installed on the roof or integrated into the parking lot.

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