Evaluating the Potential for Rooftop vs. Central PV Generation in Managua, Nicaragua

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***Abstract* — Nicaragua currently finds itself at the cusp of a renewable energy transition. In 2013, the country's annual generation mix was composed of bunker fuel oil (53%), wind (13%), geothermal (16%), biomass (6%), small hydropower (< 30MW; 11%), and imports/exports across the Central American interconnection line (1%), with ambitious targets for renewable energy growth by 2017 (79%) and 2026 (93%). The solar resource is one that is widely available in Nicaragua and elsewhere in the region, but has thus far remained undeveloped and unexplored by the sustainable energy literature. Here we develop a methodology for estimating available area for rooftop PV space denoting it *'urban clustering'*, and use a linear program to minimize the cost of solar generation deployment (rooftop vs. central PV) at different penetration levels. Our goal is to minimize cost of solar deployment while meeting different levels of peak daily demand for the capital city of Nicaragua (Managua). We find that the optimal solar technology choice (rooftop vs. central PV) changes depending on our cost assumptions (cheap vs. expensive central PV), and use correlation analysis (including a sample correlation coefficient) to evaluate how well this resource could be integrated with current wind penetration levels and hourly demand. We don't find evidence of smoothing, but we do find that their aggregate output is well correlated with demand, signaling that these resources would be useful at meeting long-term goals of renewable energy integration.**

I. Introduction

A. Opportunities and challenges in solar generation

The solar industry has seen substantial growth worldwide over the past decade. In the US, 2013 saw a 41% increase in solar photovoltaic (PV) installations over 2012 [1]. Globally, solar generation grew by a factor of 49 between 2000 and 2012 [2]. This growth can be attributed to many factors, such as substantial declines in PV production costs, government subsidies, and technology preference. Despite the recent decline in the cost of new PV systems in the US (15% over the course of 2013 [1]), generation from solar panels is still more expensive than many other sources of electricity [3]. This indicates that other benefits to solar installations are driving these recent investments.

Perhaps the most obvious opportunity in solar generation is that of reducing carbon emissions. On a life-cycle scale, coal and natural gas electricity emits an estimated 40 and 25 times the amount of CO_2eq as PV [4]. This is especially beneficial for governments who have set forth emissions reductions goals. Another opportunity, particularly for emerging economies, is that of energy independence. Solar panels, even if not manufactured domestically, create a domestic energy source once purchased and reduce reliance on fossil fuel imports. Lastly, the ability for solar generation to exist at all scales creates opportunity for private or personal investment and immediate deployment before large-scale installations are technically or economically feasible.

Of course, these opportunities do not exist without challenges. Of course economics are a concern, as the up-front investment is much more significant with PV than other generation types, and long-term payoffs are uncertain. The non-dispatchable nature of solar power is also a concern, and may require storage or demand management operations before large-scale deployment is feasible. Beyond that, variability and uncertainty in generation can cause grid management concerns and require costly power electronics installations [5].

B. Local Context

Nicaragua is perhaps the most interesting case in the Western Hemisphere currently undergoing a renewable energy transition. Over the last two decades, GDP and national energy consumption have grown at 4.4% and 5.7% per year [6], and today, oil accounts for over 80% of all energy imports (energy imports >45% of total annual national demand) [6]. Over 55% of Nicaragua's revenue from exports goes towards covering this expenditure [7]. This matters, because despite strong GDP growth (4.7%/year), the country still holds the 129th position in the UN's HDI, the lowest position in the Western Hemisphere after Guatemala and Haiti [6]. Nicaragua's dependence on bunker fuel oil has reduced its ability to invest and focus on other sectors of society that are crucial to the country's long term human development goals.

More recently Nicaragua has developed a vision and commitment to becoming a regional leader in renewable energy. In the last five years (2009-2014), it installed

~190MW of wind energy capacity (14% of totaled installed capacity), underwent an intensive geothermal technical capacity training in partnership with Iceland, and in 2012 received $US 292 million in new clean energy investments [8,9]. Between 2006 and 2012 the country received $1.5bn of cumulative renewable energy investment (5% of GDP), and today renewable energy (excluding large hydro) accounts for 45% of the country's total installed capacity [10]. Yet, despite this great progress, the country's ambitious goals (79% and 93% renewables by 2017 and 2026 respectively) seem daunting. Although at the end of 2013 renewable energy generation represented 35% of the total, new capacity and investments would have to grow steadily at 11% per annum to reach the 79% target, and at 4% per year to reach the 2026 target [11]. Solar energy (central and rooftop PV generation) is a resource that could help Nicaragua reach its goals, but has thus far remained unexplored despite the resource's large potential.

C. Relevant Literature

No analysis has been done on potential PV penetration and comparison of distributed vs. centralized generation for Nicaragua. However, similar research has been done elsewhere. In 2010, a group from Stanford University presented at the Large-Scale Solar Technology and Policy Forum on distributed vs. centralized power generation in California [12]. They discussed the infrastructure concerns of each system, with distributed PV causing voltage management issues, and centralized generation resulting in need for additional transmission lines and losses associated with them. These factors are relevant to Nicaragua, as less sophisticated grid management may cause more reliability issues due to intermittency, particularly with distributed PV in the absence of storage. The issue of power losses and transmission construction is not analyzed for this paper, but would be relevant for future work.

Researchers from Lawrence Berkeley National Lab thoroughly analyzed the costs of German and U.S. solar power systems in an effort to determine a reason for the large gap between the two countries [13]. This study detailed each cost of a residential PV system, from materials and manufacturing to labor, taxes, and profits, and provides insight as to the importance of using local cost structures. For this analysis, U.S. costs will be used due to lack of knowledge of Nicaraguan PV costs, but a second scenario using the costs recently incurred at one nearby commercial PV plant will also be analyzed.

Additional cost analysis, focused on future potential for increased solar generation in the U.S., was performed by Fthenakis, Mason, and Zweibel [14]. In addition to PV systems, this study analyzed concentrated solar power (CSP) and intermittency reduction by integration with compressed air energy storage (CAES). Depending on the desired level of solar penetration in Nicaragua, grid-scale storage solutions may play an extremely important role. This study helps to guide our analysis on scale, costs, and timelines for implementing these technologies.

D. Focus of this study

The primary goal of this study is to investigate the level of investments in distributed rooftop and central PV that would be required to help meet various levels of Managua's energy demand. We seek to minimize the cost of solar deployment while meeting different levels of peak daily demand. We evaluate technology choices (rooftop vs. central PV) under two different cost assumptions (cheap vs. expensive central PV), and use correlation analysis (including a sample correlation coefficient) to evaluate how well this resource could be integrated with current wind penetration levels and hourly demand. To our knowledge this is the first analysis to explore large-scale solar generation in Managua, Nicaragua, and elsewhere in the region.

II. Technical Description - Data

A. Demand Data

In Nicaragua, residential loads (33%), industrial loads (25%), and 'general loads' (23%) account for over 81% of the total load in the country [10]. Agricultural demand (irrigation), lighting, and pumping, although important for the country, still represent a very small fraction of total demand (13% of the total). None of the energy sectors depict a temporal trend except for agriculture (irrigation), for which demand significantly drops as the summer monsoon arrives and lasts from May through November. Annual demand has been growing at six percent per year and peak demand grew two percent from 2012 to 2013 [10].

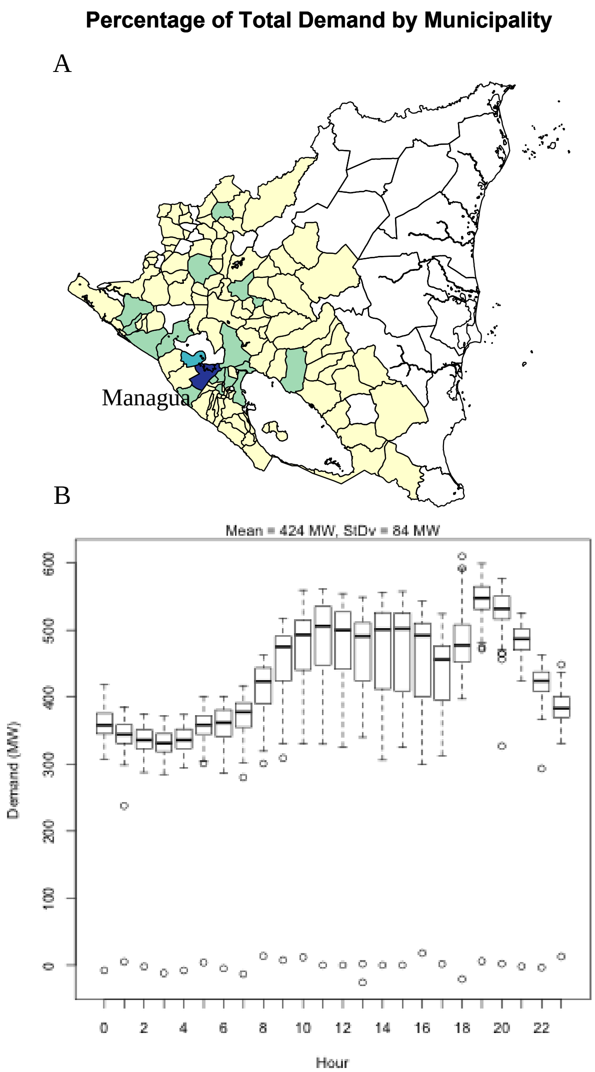

Fig. 1. The capital city of Nicaragua (Managua) accounts for approximately 30% of total annual energy consumption [A], and boxplot of hourly energy demand in Nicaragua [B].

Geographically, the department (state) of Managua accounts for over half (53%) of national demand (the capital city accounts for 31%), followed by Chinandega (8%), Masaya (6%), Leon (5%) and Granada (4%). Year-to-year growth rates (2012-2013 data) are highest in Chontales (21%), Jinotega (16%), Chinandega (15%), Carazo (13%), and Masaya (13%). Managua's year-to-year energy demand growth is relatively smaller, but still high (7%). Hourly demand data in Nicaragua is representative of a typical residential load profile curve: people wake up (6.00 – 9.00 am), they work (9.00 am – 5.00 pm) and arrive home at about 6.00 pm with maximum daily demand occurring at about 7.00 pm [11]. This hourly demand curve is shown in Figure 1. For the purposes of this study we assume Managua's demand to be 30% of total national demand.

B. Wind and Solar Data

Average solar global irradiation in Nicaragua is 5.21kWh/m^2-day with the Pacific and Central part of the country receiving the most sunlight throughout the year [15]. Global irradiation averages range as high as 5.7 kWh/m^2-day in Matagalpa, to as low as 4.6 kWh/m^2-day in Madriz. In terms of seasonal variability, February-May are both the hottest and sunniest months of the year, while the rainy season (June – November) has the lowest irradiation levels [15]. Hourly solar irradiation data (global, horizontal and direct diffuse W/m^2) were obtained from Nicaragua's open EI database.

Solar costs are obtained from the national renewable energy lab's (NREL's) analysis of the soft and hard costs of residential ($5.22/W) vs. commercial ($4.05/W) installations. These costs include total hardware, transaction, and supply chain costs, labor, permit fees, and indirect corporate costs. We also use costs from the first central grid-tied PV installation ($12W) in Nicaragua that was developed jointly by the Japanese International Cooperation Agency (JICA) and Nicaraguan Ministry of Energy and Mines.

On an annual average, Nicaragua currently generates approximately 13% of its total generation with wind energy [11]. At peak production, on the other hand, wind energy can produce as much as 45% of the country's total production on an hourly basis [11]. Spatio-temporal correlation between the five plants located in the shores of lake Managua is relatively high (0.53), and on average, they present both similar patterns in hourly and monthly variability. On a daily average, wind generation drops at 10 am and begins rising again at 3.00 pm. On a monthly basis, wind generation drops in March and rises in

October, with the periods of greatest hourly wind generation and variability occurring during the rainy season (May – November). Hourly wind generation profiles for 2013 were obtained from Nicaragua's national dispatch center (CNDC).

C. Urban Clustering

Distributed rooftop generation is limited by the amount of available space for development throughout Managua. In the absence of detailed measurements or census data, satellite images may be used to quantify this constraint. A spatial analysis was conducted using Google Earth tools to estimate the total roof area in the city.

Fig. 2. Area of Managua analyzed to determine percent of roof space in the densest parts of the city. Analysis conducted using Google Earth.

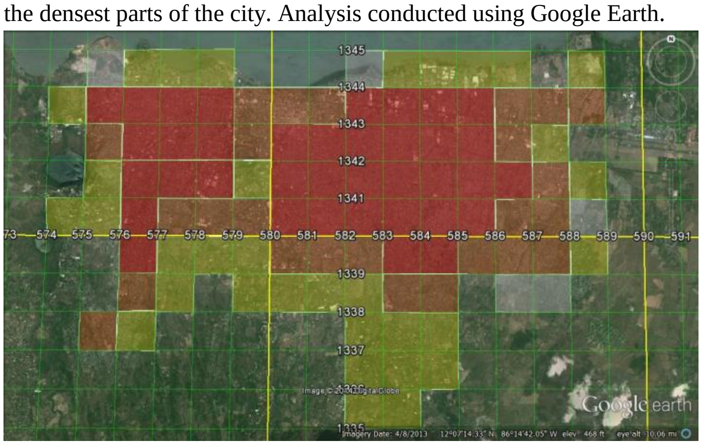

Fig. 3. Map of Managua with a 1km by 1km grid overlay. Each area is shaded to represent density relative to the densest area of the city. Red is 100% density, orange 75%, yellow 50%, and white 25%. Areas without significant roof area are not shaded.

First, a 0.25 km by 0.25 km area was analyzed as precisely as possible using tools to mark and measure areas assumed to be rooftops based on satellite images. Calculations revealed this area to be approximately 19.8% roof space, as shown in Figure 2. In order to scale this measurement to the entire urban area, a grid overlay was used to separate the city into 1 km by 1 km grid areas. These areas were then categorized based on their density relative to the representative area. The representative area was chosen in one of the densest parts of the city, so relative densities for other areas were 100%, 75%, 50%, 25%, and 0%. A map of Managua with relative densities marked is shown in Figure 3. For the 99 km^2 of Managua thought to have significant roof availability, a total of 13.4 km^2 of roof space was found to exist. Roof space available for solar development was conservatively constrained to half of the total roof area estimated.

III. TECHNICAL DESCRIPTION - METHODS

A. Photovoltaic System Modeling

A disconnect inherently exists between the design specifications and ratings of solar panels and the way they actually perform. This is due to standard testing conditions, which do not reflect a real operating situation but are necessary for panel comparability, and location-specific characteristics such as temperature and irradiation that effect performance. Due to this disconnect, calculations must be performed to analyze the actual generation potential for any given installation capacity. This analysis is especially important when an installation is meant to generate a set amount of energy (in our case, a percentage of peak daily demand). This relationship helps connect costs (typically represented in terms of installation capacity) and resulting energy.

To connect panel rating to performance, a capacity factor is typically used. This metric quantifies the amount of energy produced each day per installed power capacity, and can be found by applying conversions to the rated panel power based on discrepancies between standard testing conditions (STC) and actual operating conditions. Solar panels are rated for the amount of DC power produced when perfectly clean, under 1kWh/m^2 of sunlight, and at 25°C. Therefore, conversions must be applied for DC to AC power inverter, dirt, and cell mismatch inefficiencies, actual sunlight exposure, and reduced performance under higher temperatures. Mathematically, this can be represented by:

$$E_{ac} = P_{rated} * E_{sun} * \eta_{inv} * \eta_{mismatch} * \eta_{temp} * \eta_{dirt} \quad (1)$$

Typical power rating for solar panels is 125 W/m^2, and typical inverter, dirt, and mismatch efficiencies are 0.9, 0.96, and 0.98, respectively. The average solar irradiation per day in Managua was found to be 5.4kWh/m^2 for the year of data analyzed. The average temperature in Managua during operating hours is 30°C, which translates to an efficiency of 0.81 [16]. The result of this calculation is that PV installations in Managua will, on average, generate 3.6 kWh of energy for every kW of installed capacity.

B. Linear Programming and Optimization and Scenario Analysis

We use linear programming to determine the amount of central vs. rooftop PV that could be developed to meet different levels of peak daily demand in Nicaragua. Our objective function attempts to minimize the cost of solar deployment:

$$\frac{min}{x_1 x_2} c_1 x_1 + c_2 x_2 \quad (2)$$

where c_1 (roof) and c_2 (central) are the costs per installed MW$_{ac}$, (\$/MW$_{ac}$) and x_1 and x_2 represent the installed capacity of rooftop and central PV (MW$_{ac}$). We constrain our model (in standard form) using non-negativity constraints, maximum available rooftop area (r_{max}), the maximum amount of installed capacity (central PV) for which there is available land area (c_{max}), and an equality constraint that ensures that we build enough capacity to meet a specific percentage of peak daily demand (D_{peak}):

$$\begin{aligned} \textit{Subject to} \quad & -x_1 \leq 0 \\ & -x_2 \leq 0 \\ & a_1 * x_1 \leq r_{\max} \\ & x_2 \leq c_{\max} \\ & g_{roof} + g_{central} = D_{peak} \end{aligned} \quad (3)$$

Where g_{roof} and $g_{central}$ represent the total daily solar production (and area) required to meet a certain amount of demand. Cost coefficients are determined from NREL's reports on the soft and hard costs of PV deployment, we determine the maximum available rooftop area with the methodology provided above, constrain the amount of central PV to be installed to 150MW$_{ac}$ (ten 15MW$_{ac}$ plants), and iterate the percentage amount of peak daily demand that should be met through solar generation be from 5% (191 MWh) to 50% (1910 MWh).

C. Statistical analysis

We use the *sample correlation coefficient*, applied to the solar *X(k)* and wind *Y(k)*, time series to evaluate the temporal correlation of solar and wind generation,

$$p_{X,Y} = \frac{\Sigma_k (X(k) - \bar{X})(Y(k) - \bar{Y}}{\sqrt{\Sigma_k (X(k) - \bar{X})^2}\sqrt{\Sigma_k (Y(k) - \bar{Y})^2}} \quad (4)$$

and we later aggregate wind and solar output to evaluate the sample correlation coefficient between their sum and hourly average demand. We use the sample correlation coefficient, and correlation plots to evaluate whether or not solar generation could help smooth wind output variability. The correlation coefficient is 1 when the time series are perfectly correlated, and -1 when they are negatively (perfectly) correlated.

IV. RESULTS

A. Optimization Results

We evaluate our linear program under two different cost assumptions. The first one uses rooftop and central PV coefficients from NREL, and the second uses a central PV coefficient from the first plant to be developed in Nicaragua. Our results suggest that, using NREL's cost assumptions, central PV alone could meet up to 15% of peak daily demand before reaching its capacity constraint (150MW$_{ac}$ – 10 central PV plants). Beyond this level, rooftop PV would begin to be deployed until both central and rooftop PV can meet up to 50% of Managua's peak daily demand. On aggregate, rooftop and Central PV generation can meet over 50% of Nicaragua's peak daily demand without being constrained by rooftop area.

Our second scenario (central PV: \$12/MW$_{ac}$) suggests that no central PV would be deployed, and rooftop PV alone could meet from 5% to 50% of Managua's peak daily demand without reaching an area constraint. Figure 4 depicts the different combinations of rooftop and central PV that would be required to meet different levels of peak demand under both scenarios. Under both scenarios, if we assume that 10% of peak daily demand could be met using solar, costs would be approximately \$US 420 million (all central PV), or \$US 540 million (all rooftop) respectively.

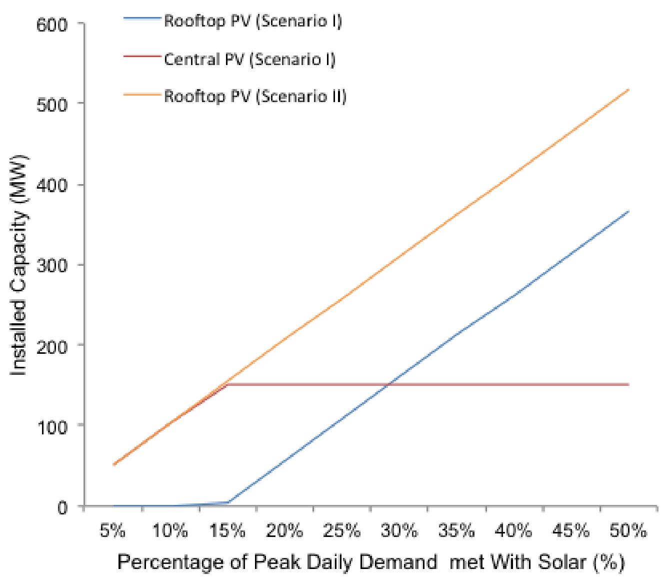

Fig. 4. Amount of rooftop and central PV installed capacity required to meet different levels of peak daily demand under two different cost scenarios (low and high central PV costs)

B. Correlation analysis

We use the assumption that 10% of peak daily demand can be met through solar generation (seven 15MW central PV plants) to evaluate the correlation between solar and wind output, and Managua's hourly demand. Plots of this correlation are shown in Figure 5. Our results suggest that there is no obvious smoothing effect from solar output for hourly ($p_{X,Y}$=p0.24), daily ($p_{X,Y}$=0.18), or monthly outputs ($p_{X,Y}$=0.42). That is, we don't find evidence to suggest that solar output could have a smoothing effect on wind intermittency (a strong negative correlation between wind and solar output would suggest the opposite). We also evaluate the sample correlation coefficient assuming storage could be available for all solar generated output from 8.00 am to 11.59 pm (~100 MWh), and find a negative correlation coefficient ($p_{X,Y}$=-0.23) when evaluating central PV generation (with storage) and wind output. When we evaluate the sample correlation coefficient between aggregate hourly wind and solar output, and hourly demand (with and without storage), we find a strong positive correlation ($p_{X,Y}$=0.50 no storage, $p_{X,Y}$=0.63 storage).

C. General Production Characteristics

Results from the model are shown in Table 1. For each level of demand to be met, the installation capacity of each type of generation can be converted to practical results: number of 15 MW plants for centralized generation and area of panels for rooftop installations.

Table 1. Optimization results converted to number of plants and area of roof generation to be built for each level of demand analyzed.

Peak Demand Met (%)	Installed Capacity (MW)	NREL Cost Scenario		Local Cost Scenario		Average Daily Generation (MWh)
		Plants (#)	Roof Area (m^2)	Plants (#)	Roof Area (m^2)	
5	53	3.5	0	0	424	191
10	106	7.1	0	0	849	382
15	159	10	73	0	1273	573
20	212	10	498	0	1698	764
35	371	10	1771	0	2971	1337
50	531	10	3044	0	4244	1910

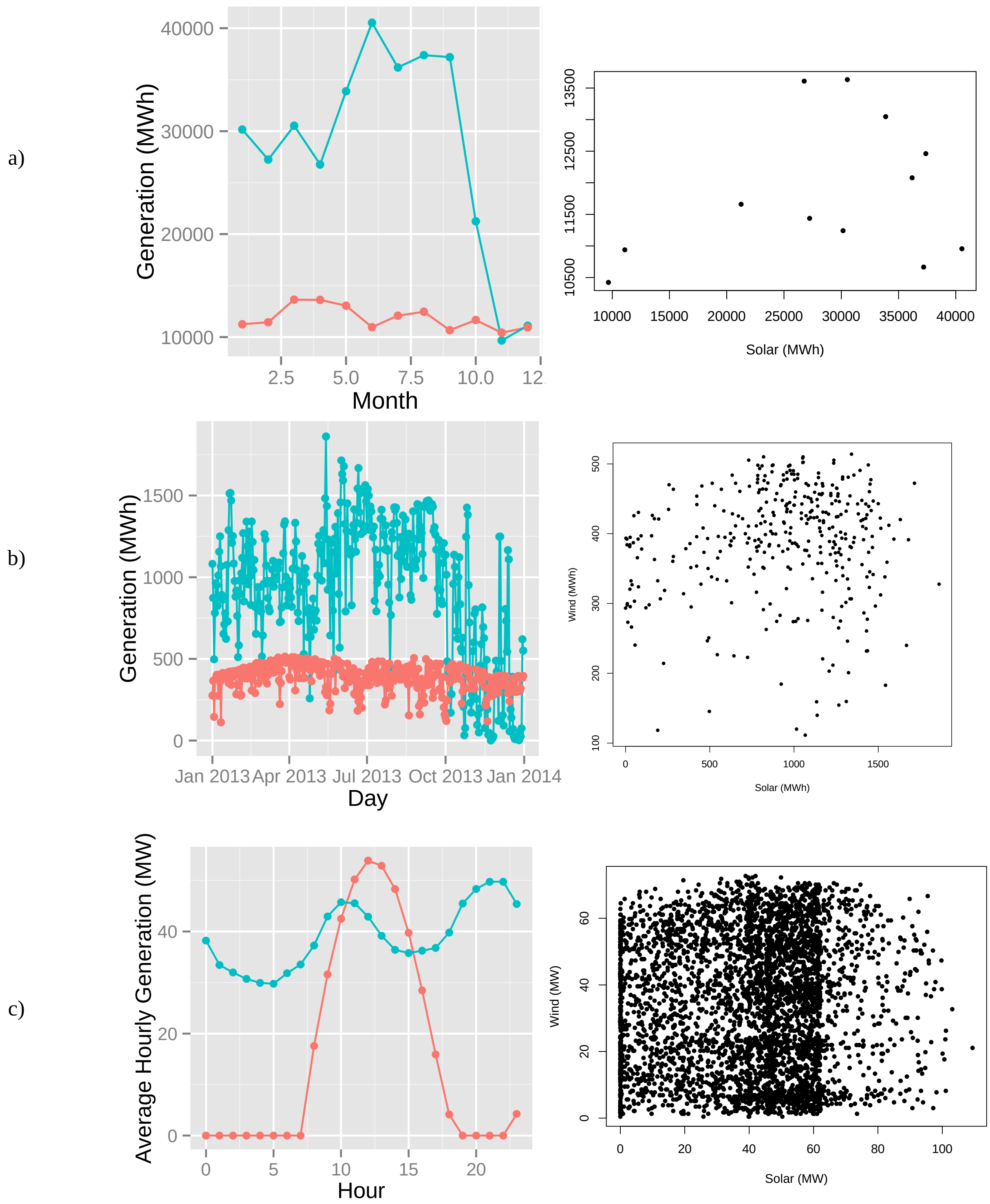

Fig 5. Monthly aggregate solar output (seven 15 MW central PV plants) and wind output: a) monthly, $p_{X,Y\ \text{hourly}}$=0.24, b) daily $p_{X,Y\ \text{daily}}$=0.18, and c) hourly $p_{X,Y\ \text{monthly}}$=0.42)

V. DISCUSSION

A. Results Interpretation

Under our two different costs scenarios (cheap vs. expensive central PV), seven new plants would be required to meet ten percent of peak daily demand (cheap central PV), and about 850m^2 of rooftop area would be required if we only used rooftop PV generation. The costs also differ, when only central PV is deployed ($4.05/$W_{ac}$) the investment required to meet 10% of peak daily demand is about $US420 million, and $US540 million when only rooftop PV is deployed ($12/$W_{ac}$, central PV). Although our linear problem allows us to investigate the optimal penetration of rooftop vs central PV generation, and determine the area and investment required, the analysis we use here doesn't allow us to compare across other energy technology choices that are prevalent in Nicaragua, including biomass, wind, geothermal and distillate bunker fuel oil plants. When we compare costs across technologies we find that biosolid ($2.4/W), wind ($2/W), distillate fuel oil plants ($0.5/W) and geothermal ($4/W) are still cheaper on a per-watt basis than central and rooftop PV [18]. It is important to consider, however, that we expect the costs of solar generation to decrease over time (in Nicaragua, and elsewhere) – and because this technology presents few local environmental and societal externalities as opposed to the technologies mentioned above, we expect growth to occur despite large cost differentials.

B. Limitations and future work

The modeling framework presented provides a simplified estimate of potential investment decisions. To accurately model the optimal investment strategies, many layers of detail will need to be added.

The most prominent detail needed in the model is accurate cost curves. Currently, the model used a linear cost for installations, which is unrealistic, particularly when considering grid-scale systems. On the simplest level, the model could be refined to account for the all-or-nothing cost that would result in building large-scale centralized PV plants. Currently, the model recommends building 3.5 plants for the 5% demand scenario, which is impractical. If we the model were constrained to only build integer numbers of plants, it may recommend 4 plants for this scenario, or 3 plants and 7.5 MW of rooftops. This could be incorporated into the model fairly easily using piecewise cost structure that jumps each time generation passes a multiple of 15 MW (the size of the plant used).

To further detail the model, plants of any size could be allowed to be built. For example, the 3.5-plant result previously mention could actually be a recommendation for a 15 MW plant and a 7.5 MW plant. Since these costs are not actually linear, bulk prices for various size plants would need to be aggregated. In general, these costs follow a concave continuous curve [17], but practical decision-making would require discrete, construction-based costs. Discretizing the costs would require an optimization model in and of itself, where two 10 MW plants would be compared to a 15 MW and 5 MW plant, for example. This new cost structure, along with, would much more accurately reflect the real options available and decisions to be made. This analysis goes beyond the scope of the current report.

Unlike the all-or-nothing cost of centralized plants, a per-MW cost is more realistic for rooftop systems. This is because distributed systems can be installed on any scale, with discretized costs (power electronics, installation) only representing a small percentage of the price. However, these costs are still more complex than the current linear representation. According to NREL, actual costs would be $6.13/W for systems of 10 kW or smaller, $5.62/W for systems of 10–100 kW, and $4.87/W for systems larger than 100 kW [17]. This is more representative of nonlinear installation costs, but still may not fully represent the cost of large-scale deployment (particularly to the utility).

For grid management infrastructure, costs would actually increase as distributed generation installations become more prominent. This would affect the rooftop cost curve, especially when considering renewable levels up to 50%. Other large-scale grid costs to consider would be transmission constraints for centralized plants. For this analysis, exact location of the plants was not determined, and therefore it is assumed that the plants could be placed on lines able to carry their capacity. In reality, if no such locations exist in Managua, either the size of the plants would need to be constrained, storage would need to be installed on-site, or the cost of new transmission lines would need to be added in.

VI. Summary

We find that the solar resource, one which is widely available in Nicaragua and elsewhere in the region, could help meet some of the ambitious goals that the country has for large scale renewable energy integration (79%: 2017 93%: 2026). *Urban clustering*, or our methodology for estimating available area for rooftop PV, together with our linear program allows a simple and first approximation for cities that are seeking to evaluate how much solar generation (rooftop vs. central PV) could be deployed to meet different peak daily demand levels. We find that the optimal solar technology choice (rooftop vs. central PV) changes depending on localized cost assumptions (cheap vs. expensive central PV), and the correlation analysis we demonstrate can be useful for evaluating how well the solar resource can be integrated with other energy technology choices. In Nicaragua, we don't find evidence of smoothing, but we do find that their aggregate output is well correlated with demand signaling that these resources would be useful at meeting long-term goals of renewable energy integration.

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