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Residential Solar PV Systems in the Carolinas: Opportunities and Outcomes

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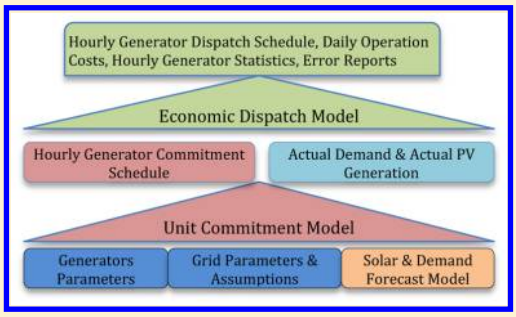
Supporting Information

ABSTRACT: This paper presents a first-order analysis of the feasibility and technical, environmental, and economic effects of large levels of solar photovoltaic (PV) penetration within the services areas of the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). A PV production model based on household density and a gridded hourly global horizontal irradiance data set simulates hourly PV power output from roof-top installations, while a unit commitment and real-time economic dispatch (UC−ED) model simulates hourly system operations. We find that the large generating capacity of base-load nuclear power plants (NPPs) without ramping capability in the region limits PV integration levels to 5.3% (6510 MW) of 2015 generation. Enabling ramping capability for NPPs would raise the limit of PV penetration to near 9% of electricity generated. If the planned retirement of coal-fired power plants together with new installations and upgrades of natural gas and nuclear plants materialize in 2025, and if NPPs operate flexibly, then the share of coal-fired electricity will be reduced from 37% to 22%. A 9% penetration of electricity from PV would further reduce the share of coal-fired electricity by 4−6% resulting in a system-wide CO_2 emissions rate of 0.33 to 0.40 tons/MWh and associated abatement costs of 225−415 (2015$ per ton).



1. INTRODUCTION AND OBJECTIVES

In 2007, North Carolina's State Bill 3 established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requiring investor-owned utilities to supply 12.5% of their retail electricity sales by 2021 through energy-efficiency measures and renewable energy sources such as wind, solar, hydro and biogas.[1] Efforts undertaken to meet this standard, which also mandates that 0.2% of electricity is generated from solar energy by 2018, resulted in the state ranking fourth in the nation for its 1011 MW of installed solar-power generation capacity in year 2014.[2]

Photovoltaic (PV) generation capacity in North Carolina is expected to continue increasing in the next 15 years. The investor-owned utility companies Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in their Integrated Resource Plan (IRP) project that the total of utility and nonutility PV installations will reach 5000 MW by year 2028 under a base-case scenario and 6774 MW under an environmental-focus-case scenario, which translates to annual energy penetration levels of approximately 2.5% and 3.4% of 2005 demand.[3,4] Although these penetration levels seem small compared to projections for other regions of the country, and considering the conclusions of large integration studies like those conducted for PJM[5] and CAISO,[6] the question of whether a balancing authority such as DEC and DEP with significant generation capacity from "must run" base-load NPPs can accommodate all of these intermittent generation resources is still open.

A total of eleven large-scale wind integration studies in the United States,[7] including the Western Wind and Solar Integration Study (WWSIS)[8] from 2010 and the Eastern Wind Integration Transmission Study (EWITS)[9] from 2011, conclude that achieving wind penetration levels of 25% to 35% is technically feasible with upgrades in transmission infrastructure and some system operational changes. Studies[8,9] also indicate that the overall savings in fuel costs (estimated at a maximum of 40% for ref 8 and 35% for ref 9, assuming fuel prices of 2 and 9.5−12 $2017/MMBtu, for coal and gas respectively) may offset any integration expenses.

Because they look at different (in most cases, larger) regions and focus on wind, the conclusions from these studies do not necessarily offer useful lessons for smaller systems considering increased penetration of distributed PV solar. Some of the strategies suggested by these studies to facilitate renewables integration, such as expanding balancing authorities to increase generator diversity and geographic smoothing effects, may not be feasible in the short term for systems operating in regulated regions such as DEC and DEP.

A total of two studies looking at the integration of PV solar for individual electric utilities suggest that feasible renewable integration levels may be significantly lower than those found in refs 8 and . J. Wu et al.[10] estimated integration costs of solar PV for a utility in Arizona considering the variability and uncertainty of solar energy and assuming a perfect forecast for wind power

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and load. They found that the combination of must run coal plants and inflexible nuclear operations results in very high levels of renewable curtailment and integration costs during low-load and high-solar periods. However, if nuclear units are assumed to be able to operate below maximum output and also provide up- and down-reserves, then under high PV penetration (14−17%), the integration cost would drop from 3.77 to 1.74 $/MWh-PV, and curtailment would be reduced from almost 18% down to 3.4% of available renewables.

Similarly, J.H. Jo et al.[11] conducted a study to determine the optimum penetration of utility-scale grid-connected solar photovoltaic systems in Illinois and found that the maximum penetration level of PV, where all of the energy generated from PV sources will be utilized 100% of the time, is 1.82% of the state's electrical-load demand.

Taking the lessons of these studies, North Carolina's significant proportion of "must run" base-load nuclear generation capacity is likely to be the main challenge to PV integration. This is because during the fall and spring seasons, relatively low electricity demand and high PV production may coincide to produce a net-demand that is lower than the system's base-load generation provided by the NPPs.[12]

Given that in the DEC and DEP service territory, nuclear generation accounts for 25% of the total generation capacity and is projected to provide 49% of system's energy over the next 15 years,[3] a study looking at the feasible levels of renewables integration in this region and its impacts seems like a much-needed step to advance the discussion of challenges and opportunities for energy sustainability in the region. Hence, the goal of this study is to conduct a first-order analysis of the limits to solar PV in the DEC and DEP balancing authority region and to explore technical, economic, and environmental effects of different levels of distributed solar photovoltaic penetration in terms of reliability, operational costs, changes in generation mix, and corresponding CO_2 emissions. To do this, we simulate the commitment and dispatch of power-generating units accounting for their technical constraints such us minimum and maximum power output, minimum down times, and ramping capability, both assuming the fleet characteristics of year 2015 and those planned for 2025.

2. MATERIALS AND METHODS

We simulate the operation of the DEC and DEP system using a unit commitment and economic dispatch model for 365 days under eight scenarios that differ in their assumptions on the levels of distributed PV generation capacity, the operational flexibility of the Nuclear Power Plants, and fuel prices. Although high penetration of distributed PV may ease transmission congestion during high-demand times and reduce energy losses, this is not taken into account within the model, which does not consider power-transmission constraints or transmission losses.

2.1. Model Description. DEC and DEP provide electric service to approximately 3.93 million customers located over a 58 000 square mile service area in North Carolina and South Carolina (see the Supporting Information, section 1), where the forecasted system's peak for 2015 is 31 468 MW, and the minimum electrical load is 10 932 MW.[3,4,14] The energy demand is met with purchases from the open market, through longer-term and purchased power contracts, and with electric generation from assets with cumulative power generation capacity of 34 492 MW (as of 2014).

We look both at the present fleet and the most likely future fleet by developing two representative models for 2015 and 2025. The model of the current fleet includes all of the coal, natural gas, hydro- and nuclear power plants of DEC and DEP reported in refs 3 and 4 (assuming the characteristics reported in the Emissions and Generation Resource Integrated Database (eGRID)),[13] while the model for 2025 includes all of the new installations and retirements described in the IRP for year 2025[3,4] (see the Supporting Information, section 2). The current fleet includes six nuclear generating stations with a combined capacity of 10 661 MW, eight coal-fired stations with a combined capacity of 10 708 MW, 33 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3460 MW, and 13 combustion turbines stations and five combined cycle stations with a combined capacity of 9663 MW. The projected generator capacity mix in 2025 reflects the approved planned retirement of 370 MW of coal-fired power plants, an addition of 3650 MW of gas-fired power plants and up-rates (i.e., capacity increases) of 139 MW on existing NPPs.[13]

In consistency with the DEC and DEP generation-expansion plan, it is assumed that nuclear generators and hydroelectric generators provide 49% and 2%, respectively, of total system energy generation both in 2015 and in 2025.[3,4]

The system hourly load is assumed to be equal to the time-series for system load for 2005,[14] the same year for which we could find hourly solar data, scaled to meet the aggregated demand levels of 2015 and 2025.[3,4] PV generation occurs at the distribution level such that the impact on the system is a reduction on net electrical load (i.e., net load = demand − PV generation).

2.1.1. PV Generation. Distributed PV power generation at different capacity penetration levels is simulated with a PV production model (PVM) that uses GIS ArcMap to merge a 10 km by 10 km data set on hourly global horizontal irradiance (GHI) for year 2005, in watts per square meter (W/m^2),[15] with a GIS shapefile containing household census data on the number of homes per square meter,[16] and assuming all household units have a roof surface to accommodate a 4 kW PV system. Each system is assumed to be made of 16 3 ft by 5 ft polycrystalline PV modules rated at 250W each, with 14−16% efficiency.[17] Actual hourly power output, genPV(W), is estimated using eq 1, which relates the amount of irradiance hitting the tilted surface of the PV modules, I_m (W/m^2), with the nameplate PV capacity, pv_c (W); a derating factor of 77% to account for reductions in power output due to soiling of the modules, wiring losses, inverter losses, module mismatch etc.; and the effect of module's temperature, T_c (°C).[17] As in ref 17, we assume PV power generation decreases 0.5% for each degree Celsius of the module's temperature exceeding 25 °C.

$$\text{genPV} = .77 \times \text{pv}_c\left(\frac{I_m}{1000\text{w/m}^2}\right) \times [1 - 0.005(T_c - 25°\text{C})] \quad (1)$$

The values of module temperature, T_c, are estimated for each grid cell and each hour of the year using data on ambient temperature, GHI, and wind speed as in ref 18. The hourly, location-specific values of the direct irradiance hitting the tilted module surface are estimated on the basis of the specific GHI and the position of the sun relative to the tilted module using a series of equations adapted from 19 (see the Supporting Information section, 2.2.3). Also, to consider the declining performance of the PV systems over their lifetime, we assume an annual compound rate of efficiency decay of 0.5%.[20]

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The PV production model determines the hourly output of each 10 km by 10 km cell based on the number of households and the PV penetration level, which is defined as the expected percentage of total annual energy generated by the distributed PV systems relative to the total annual energy consumed within the system. Using load data from year 2005 as a reference, if 7% of households had 4 kW PV systems, then PV would reach 1.1% penetration, while installations in 100% of households would result in a PV penetration of 16.3%. PV power production from all cells is aggregated to get the total hourly PV generation, which is then subtracted from the demand to obtain the net-demand for the system. The PVM is validated by comparing simulated PV power output levels from NREL's PVWatts System Model[17] as explained in the Supporting Information, section 2.2.3.

2.1.2. Generator Operational Parameters and Costs. Nuclear plants are assumed to run constantly (i.e., we do not simulate shut-downs or start-ups of NPPs). Hydroelectric plants are assumed to have a required minimum run time of 1 h and a required minimum down time of 1 h, which allows them to turn on and off as needed with no restraints,[21] but are constrained to operate only from 7 a.m. to 8 p.m. and to not exceed water availability limits (the Supporting Information, section 2.2.1). The assumptions on the performance and operational constraints of fossil-fired generators are summarized in Table 1. Major characteristics of each power generator such as type, maximum capacity, average heat rate, and average CO_2 emissions were obtained from the eGrid database[13] for the analysis with the 2015 fleet and from the Integrated Resources Plan reports for the 2025 case. Additional operational parameters were determined using information from multiple sources. Minimum run and down times, fixed costs, start-up costs, minimum economic capacity operational levels, and generators ramp rates were taken from reports issued by the Electric Power Research Institute (EPRI);[22] the National Renewable Energy Laboratory (NREL);[23] Energy and Environmental Economics, Inc. (E3);[24] a generator dispatch study conducted by the Federal Energy Regulatory Commission (FERC),[26] which contains a set of generator parameters based on historical performance and bidding data in the PJM electricity market; a report produced by Intertek APTECH for the National Renewable Energy Laboratory (NREL) and Western Electricity Coordinating Council (WECC);[27] and the IEEE Power and Energy Magazine.[25] Estimates of the start-up heat rates were obtained from ref 25. A summary of the findings of these reports in relation to our choices of parameters is presented in the Supporting Information, sections 2.2.5−2.2.6.

Table 1. Assumptions on Operational Parameters and Costs for Conventional Generators

parameter	unit	plant type		
		coal	NGCC	NGCT
maximum capacity	MW	nameplate capacity (NPC) as reported in eGrid		
minimum generation[ab]	MW	$0.1295 \times NPC^{1.1749}$	$0.25 \times NPC$	$0.25 \times NPC$
start-up heat rate[c]	MMBtu/MW	16.5	2	3.5
average heat rate	MMBtu/MW	annual heat rate as reported in eGrid		
minimum down time[d]	hours	9	3	2
minimum up time[d]	hours	15	4	2
maximum ramp rate[e]	MW/Hr	0.85NPC/Hr	NPC/Hr	NPC/Hr
CO_2 emissions rate	Lb/MMBtu	as reported in eGrid		
fixed costs[f]	$/kW/year	35	10	9
start-up costs[g]	$/MW	94	35	36

[a]We treat the minimum economic generation level as an operational constraint. For coal-fired generators, the feasible level of minimum generation is assumed to be a power law function of name-plate capacity with parameters estimated from the data in.[26] [b]The minimum economic generation level for gas-fired generators is 25% of nameplate capacity.[22] [c]Start-up heat rate is as indicated in ref 25. This value is used for estimating emissions from start-ups. [d]Minimum down and up times are as indicated in ref 26. [e]Maximum ramp rate as suggested by refs 22 and 23. [f]$/kW/year depending on generator type as indicated in ref 24. [g]Start-up costs include the fuel and electricity needed to crank the generator motor and are obtained from ref 25 and verified to be consistent with ref 27.

2.2. Unit Commitment, Economic Dispatch, and PV Power-Generation Models. We use a unit commitment (UC) model and economic dispatch (ED) model (UC−ED) to simulate the hourly dispatch of all generating units in the system that balances total power generation with net load (electrical demand minus PV generation) at the lowest possible cost. The UC model takes as inputs the characteristics of the coal, gas, nuclear, and hydropower resources in the DEC and PEC system (costs, performance, and operational constraints), as well as hourly values of the forecasted electrical load and PV power generation, to prescribe a day-ahead hourly generator schedule. The solar forecast errors are generated from actual historical data using a statistical model described in ref 28 and summarized in the Supporting Information, section 2. As in ref 29, the day-ahead forecast error of hourly electrical load as a percentage is assumed to be a random variable following a normal distribution with mean 0% and standard deviation 1%. In this way, the day-ahead hourly load forecast is set equal to the actual load value increased or decreased by a percentage equal to the randomly generated forecast error.

The ED model determines hourly generator dispatch based on realized load and PV generation. Its formulation is similar to that of the UC model, with the only difference being that the commitment status of a generation unit is no longer a decision variable and instead is taken as a parameter set equal to the solution of the previously run (i.e., day-ahead) UC. The model integrating the UCM and ED is almost identical to the baseline model presented in ref 30, with the only difference being its hourly resolution (due to lack of more granular demand and PV production data for DEC and DPC) and the additional constraints to represent the NPPs and the hydropower generators (see the Supporting Information, section 2). Outputs from the UC/ED include the daily cost of meeting system's electrical demand, generator-level hourly information such as status (on−off), generation level (MW), spinning reserves (MW), start-up and shut-down events, and system error flags indicating a system imbalance at a specific hour, all of which allow estimating the system costs and CO_2 emissions. Simulation of operations is performed daily, assuming a forecast 32 h ahead, and iterating for 365 days. The UC and ED models assume that load-generation imbalances do not cause complete system failure and can be addressed operationally through manual generator adjustments, curtailment, demand response, imports, or other measures. Hence, the security requirements of the system are assumed to be such that overgeneration and under-generation are penalized at a rate of $10 000/MWhr. This value implies that these imbalance events can be corrected technically or

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Table 2. Description of Modeled Scenarios

scenario	NPP generation	generation fleet	2015 fuel price per MMBtu: 4.65(NG) 2.34 (coal) 2015$/MMBtu)	2025 fuel prices per MMBtu: low (5.43 (NG) 2.80 (coal) (2015$/MMBtu))	mid (6.18 (NG) 2.92 (coal) (2015$/MMBtu))	high (7.81 (NG) 2.99 (coal) (2015$/MMBtu))
A	fixed[a]	as in 2015[c]	X			
B	flexible[b]		X			
C	fixed[a]	as in IRP for 2025[d]		X		
D	fixed[a]				X	
E	fixed[a]					X
F	flexible[b]			X		
G	flexible[b]				X	
H	flexible[b]					X

[a]NPPs operate at a constant capacity factor of 87%. [b]NPPs are able to ramp their power generation from 70% to 100% of their maximum generation capacities within 1 h. [c]Scenarios A−B assume the generator capacity mix reported in 2014 DEC and DEP IRP reports.[3,4] [d]Scenarios C−H assume the projected generator capacity mixes for 2025 resulting from the approved planned retirement of 370 MW of coal-fired power plants, the addition of 3650 MW of gas-fired power plants, and up-rates of 139 MW of NPPs.[3,4]

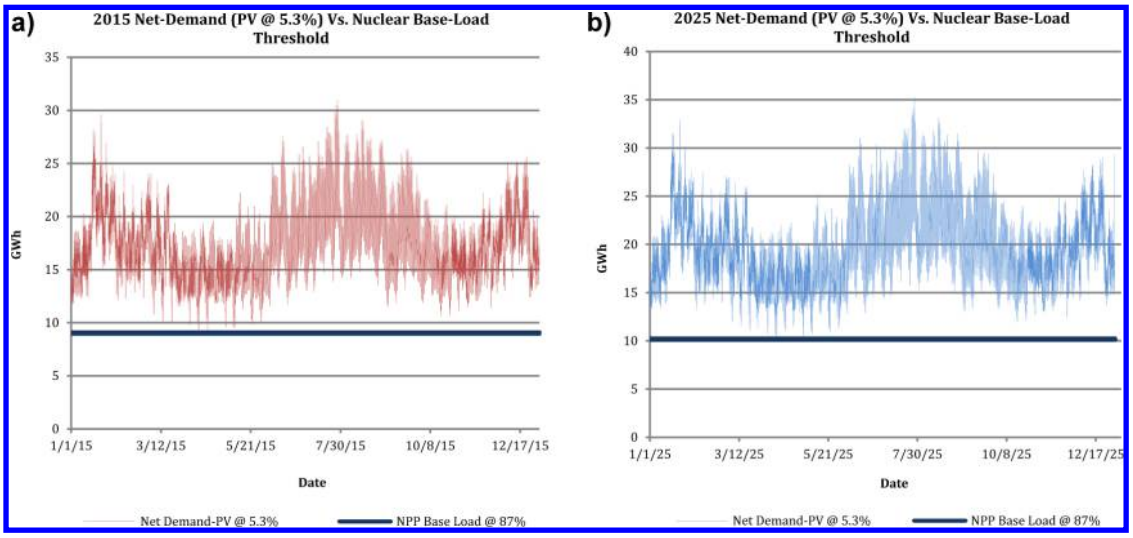

Figure 1. Net system demand under (a) scenario A (year 2015) and (b) scenarios C, D, and E (year 2025). The horizontal line shows generations from nuclear power plants, which for both years is set to be equal to 49% of the system's total generation. It is clear that for both fleets (2015 and 2025), the net demand depicted is the lowest that the system can handle with its lowest values, being just above the NPP generation line.

operationally at a penalty cost of $10 000/MWhr, which is consistent with modeling assumptions in the unit commitment study completed by FERC.[26] We also assume that power generation spinning reserves must be equal to 3% of the total demand and 5% of total renewable energy as proposed by NREL in ref 31. As in ref 26, a penalty of $1000/MWhr is incurred if this requirement is not met.

2.3. Scenarios Description. System's operations are simulated under eight scenarios that differ in assumptions about the fleet (i.e., year 2015 or 2025), flexibility of the nuclear power plant (NPP) (i.e., fixed power output or flexible power output), and fuel prices (Table 2).

Scenarios A and B have the same generator capacity mix as reported in the 2014 DEC and DEP IRP reports.[3,4] Although scenario A assumes fixed generation capacity from NPPs at a constant capacity factor of 87%, scenario B assumes that NPPs can daily ramp up and down within 100−70% of the their full generation capacities, similar to many NPPs in Europe and the United States.[22,32] These scenarios assume 2015 coal and gas prices are equal to those projected by the 2015 AEO, while $24.4/MWh is assumed as a variable production cost (i.e., O and M and fuel costs) for the NPP in 2015,[33] and hydroelectric generators are assumed to have a marginal cost of $0.

The rest of the scenarios (C−H) consider the projected generator capacity mixes in 2025[3,4] and reflect the approved planned retirement of 370 MW of coal-fired power plants, an addition of 3650 MW of gas-fired power plants, and up-rates of 139 MW of NPPs. Scenarios C−E assume the NPPs cannot ramp down generation and hence operate at a constant capacity factor of 87%.

These scenarios represent different coal to natural gas-price ratios reflecting low, high, and baseline natural gas estimates from the 2014 Annual Energy Outlook.[34] We call these the "inflexible NPP scenarios". Scenarios F−H use same fuel prices scenarios but assume that NPPs are able to ramp their power generation from 70% to 100% of their maximum generation capacities within 1 h. We call these the "flexible NPP scenarios" [see the Supporting Information, section 2.3]. The NPPs are assumed to have a production cost of $28.6/MWh in year 2025 (assuming a 1.6% annual increase in fuel prices since the year 2015, the same increase observed in years 2010−2015[33]). The marginal fuel costs for hydro-electric generators are assumed to be $0. Marginal fuel costs for coal and natural gas generators during

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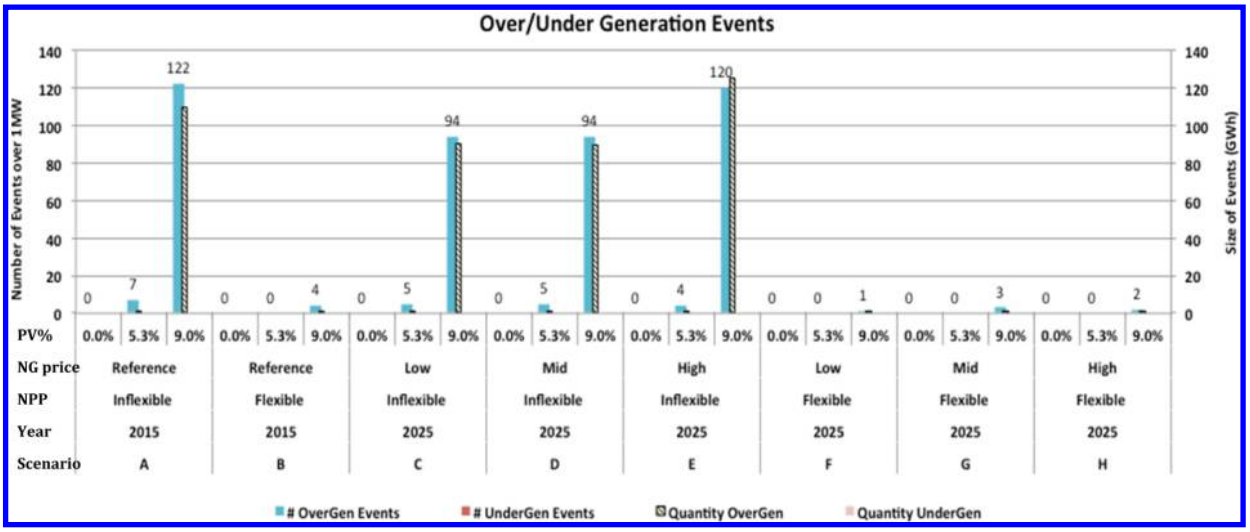

Figure 2. Imbalance events in the simulated year. The high number of over- and undergeneration events observed for scenarios A, C, D, and E when the NPP is inflexible and 9% of generation comes from PV solar suggests that this level of PV penetration is unfeasible. Note that the number and size of events results from the particular realizations of roof-top PV solar and the demand for the simulated year and hence is likely to change for other assumptions about hourly demand and solar resources.

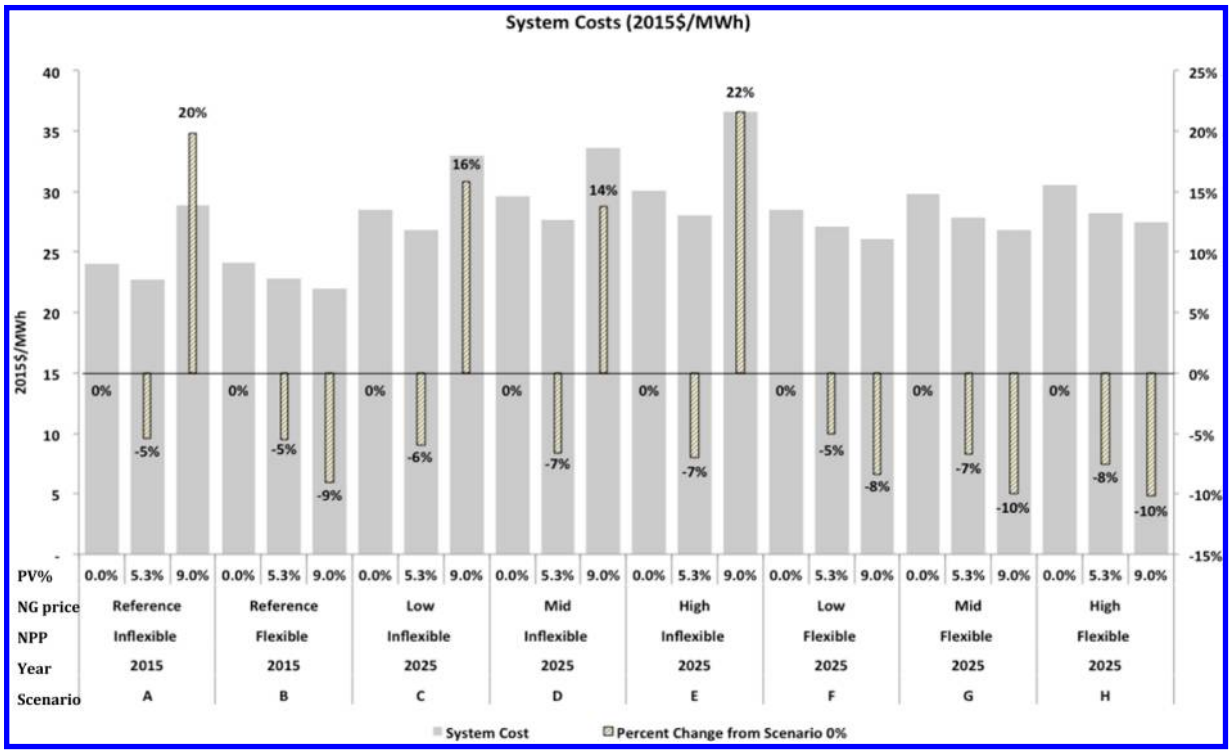

Figure 3. System cost results by scenario. The units of the left axis are $/MWh. The right axis measures the percent difference in costs relative to the equivalent scenario at 0% PV penetration. The percentage value inside the bar is the change in system's cost relative to the scenario with no PV generation. Results show that for scenarios A, C, D and E (i.e., scenarios with inflexible NPP), the system's cost of providing 9% of demand with PV solar are at least 14% higher than the baseline costs. Instead, a PV penetration level of 5.3% of total demand reduces systems costs by at least 5% for all scenarios.

operation between the minimum and maximum power output are determined by the generator average heat rate and the corresponding fuel price.

2.4. Prices and Costs Conversions. Coal and gas prices in 2015 and in 2025 for the midprices or baseline scenario are from the early release of the AEO2015 report.[34] Fuel prices for the low- and high-price scenarios in 2025 are from the AEO2014 report[35] because AEO2015 does not present fuel price sensitivity cases. All prices are converted to 2015$ using EIA factors (see the Supporting Information, section 3.4).

3. RESULTS

The following results assume the PV systems' performance is given by its efficiency in the first year of operations. However, estimates of the CO_2 abatement costs take into account the efficiency decay of the PV systems over 25 years.

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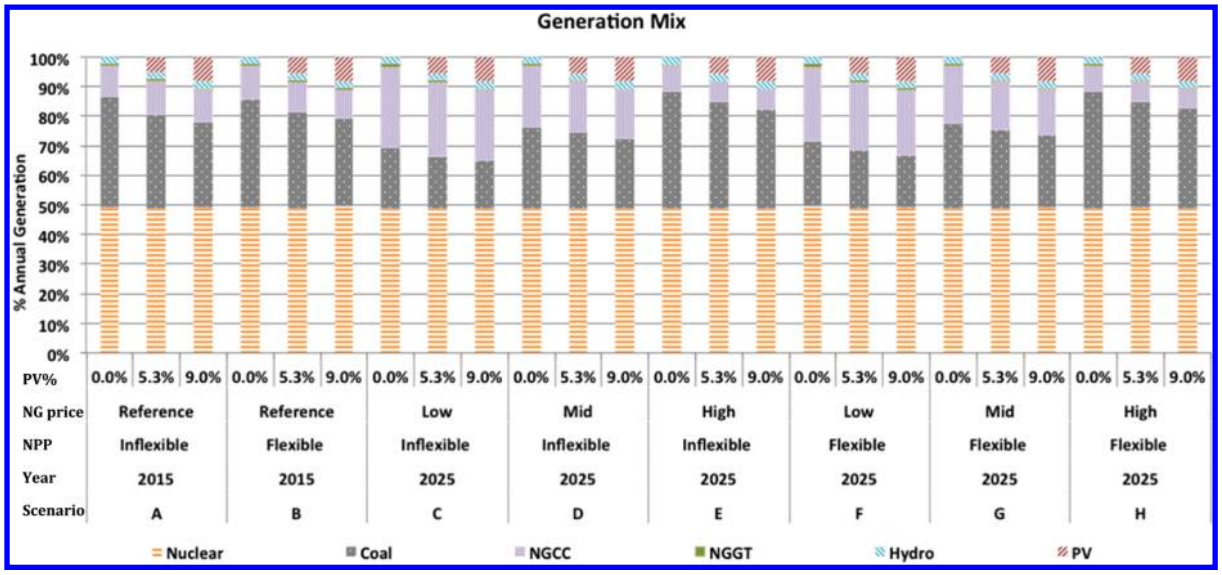

Figure 4. Generation mix by scenario. Coal generation is reduced for all the 2025 scenarios, assuming low and middling natural gas prices (i.e., scenarios C, D, F, and G), due to the coal-plant retirements. An increase of PV penetration to 5.3% or 9% of generation further reduces the share of coal-fired generation in 2025.

3.1. Limit Imposed by Inflexible Must-Run Nuclear Power Plants. Because nuclear power generation is set to account for 49% of system generation in both 2015 and 2025 (following NPPs upgrades to increase their capacity by 139 MW), the maximum level of PV penetration is limited to 5.3% of electrical load. This limitation is illustrated in Figure 1, which shows that for a PV penetration level of 5.3%, net-demand dips below the power production from base-load nuclear plants during the spring, when energy demand is low and PV production is high.

Note that this result stems from the relationship between the projected PV generation with the fixed power output of the NPPs and, hence, represents the maximum PV penetration that could be achieved in the absence of any other constraint.

3.2. Demand−Supply Imbalance Events. In addition to the limiting threshold observed above, other limitations of the system become apparent in the form of over-generation events and under-generation events. Over-generation events are observed when the electricity supply, including generation from intermittent renewable resources such as solar PV, exceeds the system's electricity demand within an operating period. These events occur due to the inability of committed generators to ramp down or shut down when demand decreases, due to either ramping or minimum up-time constraints. Under-generation events are observed when the electricity supply, including generation from roof-top solar PV, is not enough to meet the electricity demand within an operating period.

Figure 2 shows both the quantity and magnitude of over- and under-generation events for three levels of PV penetration (0%, 5.3%, and 9%) under the eight scenarios considered. Results show that the rate at which these events occur increases with the PV penetration. Although as mentioned, these types of events are associated with a penalty of $10 000/MWh, they occur because of the system's inability to redispatch resources to strike a balance between power generation and consumption. On the one hand, under scenarios that have inflexible NPP generation (namely A, C, D, and E), over-generation events increase as the hourly system loads decrease and approach or dip below the NPP base-load generation threshold. On the other hand, when NPP ramping capabilities are enabled (i.e., scenarios B, F, G, and H), the system experiences few over-generation events even at the high PV penetration levels of 9%. Although these over-generation events do occur, they are extremely rare. For example, under scenario G at penetration levels of 9%, which is the situation with the highest number of events among all flexible scenarios, only 3 h of over-generation occurs (of the 8760 h of simulation), and the 377 MW by which supply exceeds demand is not more than an average of 1.5% of the system's demand at those times.

3.3. System Costs. Figure 3 shows the annual operating system costs for each scenario. Such costs include generation costs and generation imbalance penalty costs. PV penetration reduced overall system operating costs in all scenarios at penetration levels below the base-load threshold limit. (Note: capital costs of the PV systems are not included as systems costs. PV systems are assumed to be customer-owned). This result makes sense because the operational costs of PV systems are $0 due to no fuel costs or variable O and M costs.

The range of reduction in costs from 0% penetration to 5.3% penetration across "Inflexible NPP" scenarios A, C, D, and E was 5−7% per MWh, and for "flexible" scenarios B, F, G, and H, the reduction was 5−10% for a PV penetration ranging from 0% to 9%. After the base-load threshold of 5.3% of PV penetration was reached in the "inflexible NPP" scenarios, the over-generation penalty costs associated with excess generation significantly increase system costs. This is the reason why under these scenarios, the system costs for a PV penetration level of 9% is appreciably higher than for a 0% PV penetration.

As expected, system costs increased when natural gas and coal prices increased across scenarios C−E and scenarios F−H.

3.4. Generation Mix. Figure 4, shows the contribution of each fuel-type generator as a percentage of annual electricity generation in the system. As discussed, in all scenarios, the generation from NPPs accounts for 49% of total electricity. Also, because the fleet of 2025 has less coal and more natural gas generation capacity (a reduction of 370 MW of coal and an increase of 3650 MW of gas-fired energy) in all the scenarios of 2025 with low or middling fuel prices, coal represents a lower

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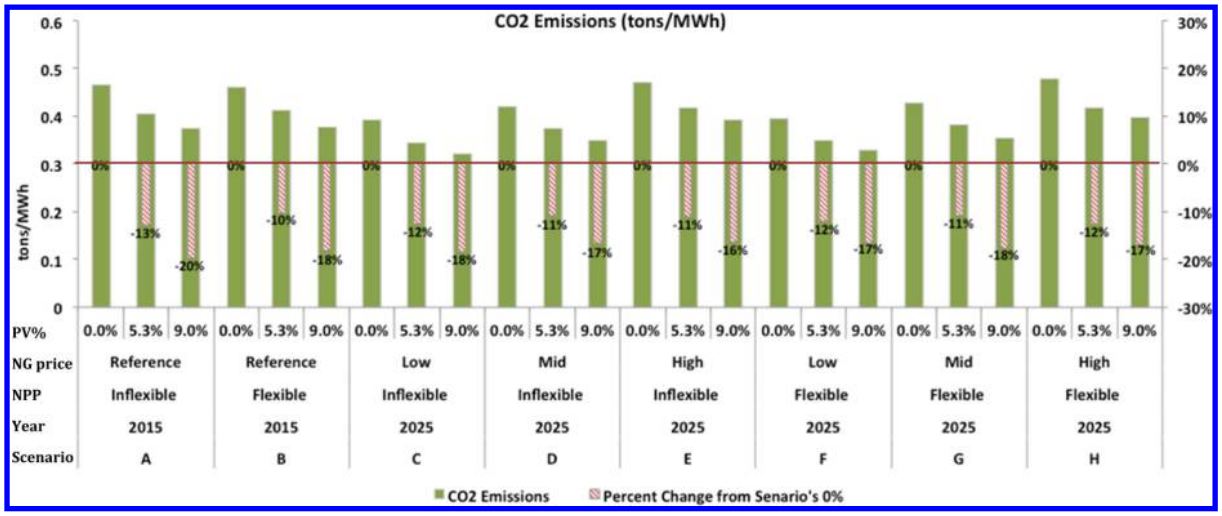

Figure 5. CO_2 emissions by scenario. Introducing PV generation reduces system's CO_2 emissions for all scenarios. Even for today's system, meeting 5.3% of electricity demand with PV solar would reduce CO_2 emissions by 10%−13% depending on assumptions about the nuclear power plant. For the year 2025, 5.3% or more of PV penetration would result in CO_2 emissions reductions of at least 11% from the already lower level expected from coal-plant retirements.

proportion of the electricity generation than in 2015. The change in the fleet composition, together with low natural gas prices, causes a decrease in the share of coal-fired electricity from 38% to 21% (i.e., 17 percentage points) when the NPP is inflexible and from 37% to 22% (i.e., 15 percentage points) when it is flexible. Instead, when natural gas prices are assumed to be high as in scenarios E and H, the share of coal generation would increase by 2 percentage points, from 38% in 2015 to 40% in 2025 for the inflexible NPP cases and by 3% (from 37% to 40%) for the flexible cases.

Comparing the fuel mix within scenarios makes it clear that a 9% of PV penetration decreases the proportion of electricity generated by coal by 4−6 percentage points. For example, 9% PV penetration with flexible NPPs would reduce the share of coal electricity from 40% to 34% under a scenario with high fuel prices. Similarly, it would reduce the share of coal-fired electricity from 22%−18% under low fuel prices.

3.5. CO_2 Emissions and Abatement Costs. CO_2 emissions decrease as PV penetration increases for all scenarios. Figure 5 shows a reduction of 11%−20% from the 0% to the 5% and 9% PV penetration cases under the inflexible NPP assumption and a reduction of 10%−18% when the NPP is flexible. In 2025, although absolute CO_2 emissions are lower due to the changes in the fleet, the percentage reductions in CO_2 achieved from a transition from 0% PV to 5% and 9% PV penetration are comparable to those of the 2015 scenarios (i.e., 16−18%). (See the table with emissions in the Supporting Information section 3.2).

It is important to note that CO_2 emissions are not reduced in proportion with PV penetration. For the cases with inflexible NPP in 2025 (scenarios C−E), going from 0% to 5.3% PV penetration achieves CO_2 emissions reductions of 11%−12%, but increasing PV penetration from 5.3% to 9% achieves additional reductions of only 5−6%. This is due to increased cycling (i.e., start-ups) and the associated higher emissions of large coal-fired plants needed to balance PV generation. (See the Supporting Information, section 3.1, for a comparison of cycling under different scenarios).

To estimate the cost at which PV reduces CO_2 emissions (i.e., cost of abatement CoA), we assume a PV installation cost of 4.90 (2015\$/W_{DC}), as was observed for residential installations completed in 2014 in North Carolina,[36] which includes the costs of PV modules, inverter, and balance-of-system (BOS). To isolate the effect of PV on emissions, we calculated the abatement cost for each scenario, taking as a reference the 0% PV case. In all cases, abatement cost is calculated as the change in system's costs divided by the changes in CO_2 emissions, where system's costs are equal to the costs of achieving the assumed PV installed capacity plus the fuel costs incurred to meet demand (see the Supporting Information, section 3.2, for formula of abatement cost).

Accordingly, the abatement cost of CO_2 for 2015 DEC and PEC system is about 305−395 (2015\$/ton) across 0−9% PV penetration levels. If the cost of residential PV system decreases by 25% in 2025 as projected in ref 36, then CO_2 emissions reductions expected for 2025 could be achieved at a cost of between 225 and 415 (2015\$/ton).

3.6. Sensitivity of Results to Assumptions about Orientation, Material, and Efficiency Decay Rates of PV Systems. The base-case analysis presented above assumes the PV systems are all made of standard polycrystalline silicon modules, are positioned to face south, and will have a 0.5% compound rate of annual decay in efficiency over their lifetime.[17] Because all three parameters may vary, we conduct additional simulations to explore the effect of alternative assumptions on the results for scenario A with a PV penetration of 5.3%.

Results show that assuming all PV systems face east, west, or north increases the overall system costs by 0.8%, 0.9%, and 1.3% relative to the baseline costs and increases the system's CO_2 emissions by 1.8%, 2.0%, and 3.5%, respectively. (See section 4 in the Supporting Information).

Assuming the PV systems are made of monocrystalline modules, which are 3% more efficient than the polycrystalline ones and 18% more expensive,[17,37] raises the total system's costs per MWh by 10.1% but reduces the system's CO_2 emissions by 0.2%. However, assuming thin-film (CdTe) modules, which are 3% less efficient and 2.8% more expensive than the polycrystalline silicon ones,[17,38] increases the total system's cost per MWh and CO_2 emissions by 2.6% and 2.7%, assuming the thin-film

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module's annual efficiency decay is about 70% higher than that of the standard polycrystalline module's.[38]

Finally, given that temperature, humidity, and moisture in some areas of the DEC and DEC region might cause the PV modules to degrade faster than the assumed 0.5% per year, we have examined the effect of higher-performance degradation rates and found that for each 0.1% per year increase in the efficiency decay rate, system costs, CO_2 emissions, and CoA increase in the ranges 0.4−0.9%, 1.0−1.8%, and 1.4−2.8%, respectively.

4. DISCUSSION

Several model simplifications limit the accuracy of our results. On the one hand, the lack of high-frequency irradiance data prevented the PVM from capturing intrahour variability in PV power output. Variation in cloud cover, rising and setting of the sun, and seasonal axial tilt are responsible for the variable nature of PV electrical generation on both short and long time scales. Solar irradiance can fluctuate instantaneously, and therefore higher frequency irradiance data (5 or 1 min) is preferred.[6] By using available hourly data, the simulation obtained with our UC−ED model may underestimate the number and magnitude of over generation and under generation events due to lack of ramping capability of the conventional power plants. On the other hand, our UC−ED model does not consider demand side management, more timely forecasts, real-time unit commitment, and other resources that could better position the system to handle the uncertain and variable PV generation.

Despite these limitations, this study provides valuable insight into what may be an upper limit of PV penetration in the absence of energy storage and demand response. This study suggests that in the DEC and DEP region, technical constraints of the power generation system allow increasing its PV penetration well beyond its current level of less than 0.5% up to near 5.3%, equivalent to 30−35% of households with 4 kW installations, when the base-load nuclear threshold is reached. Accommodating greater levels of PV generation up to 9% (52−57% of households) is feasible when NPPs are allowed to ramp down to 70% of their nameplate capacities. The limitation is due to other system operation constraints such as up- and down-ramping, minimum up- and down-times, and minimum plant generation constraints. Unless the system has enough energy storage or curtailment and protection measures in place, the surplus generation from the PV system may have negative impacts, including voltage rise, power fluctuations, power factor changes, harmonics, unintentional islanding, fault currents, and grounding issues.[39]

The planned retirement of 370 MW of coal-fired power plants over the 2015−2025 period will result in a noticeable reduction in CO_2 emissions, which can be furthered with increased penetration levels of PV.

This study shows that the integration of 9% PV generation can reduce system CO_2 emissions by 16−18% in 2025, which would result in a system CO_2 emissions rate of 645−800 lbs/MWh that is notably below the EPA's proposed caps for North and South Carolina by year 2030 of 1077 lbs/MWh and 840 lbs/MWh, respectively.[40] However, the cost of CO_2 abatement by these means would be relatively high compared with other alternatives, such as the installation of advanced natural gas combined cycle (e.g F-Class) or ISCC plants.[41]

The high costs of abating CO_2 are mainly due to the high costs of PV installation in the region. Although the median cost of residential PV in the U.S. in 2014 was 4.44 (2015\$/W_{DC}), the cost observed in North Carolina was 4.90 (2015\$/W_{DC}), the second highest in the nation.[36] If installation costs were the same as the median cost mentioned above, then abatement costs would be 275−360 2105\$/ton for 2015 and 205−375 2015\$/ton in 2025.

Estimated abatement costs would be even lower if rather than using NRELs installation costs, we used those reported by the Solar Energy Industries Association (SEIA) or the GTM research group, which are 25−30% lower.[42] In this case, abatement costs would vary between 150 and 270 \$/ton for 2025. For PV to achieve the same abatement costs of an advanced combined cycle power plant (i.e., 70−90 \$/ton) that delivers the same annual electricity generation and runs in the same system, installation costs should decrease by 55−65% to about 1.55−2.00 2015\$/WDC.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.5b04857.

Additional details on the Duke Energy Carolina (DEC) and Duke Energy Progress (DEP) Balancing Authority region; modeling platforms; start-up CO_2 emissions and abatement costs calculation; and sensitivity of results to assumptions about orientation, material, and efficiency decay rates of PV systems. Figures showing the DEC and DEP Balancing Authority regions, DEC and DEP installed generation capacity by fuel type and technology, modeling schematics, DEC and DEP regions showing household density, trend line of the minimum economic capacity of coal-fired power plants, total annual start-up CO_2 emissions and total number of start-ups for large coal plants for all 430 scenarios, and cost of CO_2 abatement under all scenarios. Tables showing unit commitment model optimization indices, parameters, and decision variables; PV penetration levels, production model variables, and production model definitions; PV output comparison of NREL PVWatts model and constructed PVM model; solar PV forecast error model's parameters; monthly maximum solar irradiance values; standard deviation values corresponding to CI intervals; summary of all assumed operational parameters; and CO_2 emissions under all scenarios. (PDF)

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Notes

The authors declare no competing financial interest.

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