Limits and Economic Effects of Distributed PV Generation in North and South Carolina

by

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Earth and Ocean Sciences

Duke University

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Peter Haff

Thesis submitted in partial fulfillment of
the requirements for the degree of
Master of Science in
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ABSTRACT

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Abstract

The variability of renewable sources, such as wind and solar, when integrated into the electrical system must be compensated by traditional generation sources in-order to maintain the constant balance of supply and demand required for grid stability. The goal of this study is to analyze the effects of increasing large levels of solar Photovoltaic (PV) penetration (in terms of a percentage of annual energy production) on a test grid with similar characteristics to the Duke Energy Carolinas (DEC) and Progress Energy Carolinas (PEC) regions of North and South Carolina. PV production is modeled entering the system at the distribution level and regional PV capacity is based on household density. A gridded hourly global horizontal irradiance (GHI) dataset is used to capture the variable nature of PV generation. A unit commitment model (UCM) is then used to determine the hourly dispatch of generators based on generator parameters and costs to supply generation to meet demand. Annual modeled results for six different scenarios are evaluated to determine technical, environmental and economic effects of varying levels of distributed PV penetration on the system.

This study finds that the main limiting factor for PV integration in the DEC and PEC balancing authority regions is the large generating capacity of base-load nuclear plants within the system. Because of the large capacity of inflexible nuclear plants, system stability is challenged at PV integration levels of 5.7% or higher. The model also finds a number of system errors, defined as imbalances in supply and demand caused by over or under generation, but the accuracy of these error estimates needs further examination due to the lack of high frequency irradiance data and other modeling limitations. Finally, we find that operational system costs decrease with PV integration although further research is needed to explore the impacts of the capital costs required to achieve the penetration levels found in this study. PV system generation was found to mainly displace coal generation creating a loss of revenue for generator owners. In all scenarios, CO_2 emissions were reduced with PV integration. This reduction could be used to meet impending EPA state-specific CO_2 emissions targets.

Contents

LIST OF TABLES

LIST OF FIGURES

Acknowledgements

This project would not have been possible without the support of many people. First, I would like to express my sincere gratitude to my research advisor Lincoln Pratson for his support and guidance on all steps of this project. I would also like to thank Dr. Dalia Patiño-Echeverri for all her instruction which has inspired and enabled me to complete this analysis. In addition thank you to the MOTESA group, especially Adam Cornelius who developed the initial version of the Unit Commitment Model. Finally thank you to Dr. Peter Haff who has generously agreed to be on my committee and has always kept his door open ready to give advice when needed.

1. INTRODUCTION

A shift is occurring within the electricity sector towards an increased usage of renewable energy generation. Concerns as to whether the current electrical infrastructure has the flexibility to support this reallocation of power generation is becoming the focus of new integration studies [1]. These concerns arise because renewable resources, such as wind and solar, can be highly variable in their electrical output since wind and the amount of sunlight directly affect their level of generation [1]. This variability, when integrated into the electrical system, must be compensated by traditional generation sources in-order to maintain the constant balance of supply and demand required for grid stability. An entity referred to as a balancing authority is in charge of maintaining this balance within a defined region by controlling the generator operations [2]. The US power system is comprised of over 100 balancing authorities who are interconnected at specific controlled interconnection points. All the generators connected to the larger electrical grid are in sync and operate at the same "speed" (of rotation) called frequency and measured in cycles per second or Hertz (Hz), which is typically 60Hz. The system remains in sync (stable) as long as generation equals the demand. Over-generation within the system causes frequency to increase, while under generation in the system causes frequency to decrease, both creating unstable conditions. While the interconnection points between balancing authorities can provide pathways for exchanges of power to relieve some over/under generation situations, large or sudden regional generation imbalances can cause protection devices in the network to isolate generators to protect them from damage [3]. This has the potential to exacerbate the frequency deviation causing more regions of the network to shut down and eventually originating rolling black-outs [3]. Therefore the role of the balancing authority is extremely important to maintaining system security. As discussed above, renewable sources add variability and uncertainty to this balance equation. Additionally each balancing authority region will respond differently to the introduction of variable renewable energy sources within their section of the electrical system because each contains a unique set of generation capacity mixes and demand profiles. Therefore systems are best studied on a case-by-case basis. The goal of this study is to analyze the technical, economic and environmental effects of increasing large levels of distributed solar Photovoltaic (PV) penetration (in terms of a percentage of annual energy production) on a test grid with similar characteristics to the Duke Energy Carolinas (DEC) & Progress Energy Carolinas (PEC) balancing authority regions in North and South Carolina. Specifically this study will analyze and attempt to quantify the following limits and system responses to increasing levels of distributed PV integration onto a test system:

1) Limitations set by existing "must-run" base-load generators that are run continuously at a set generation level
2) System imbalance events, referred to in this study as *error events*, caused by over/under generation with respect to demand
3) Changes in annual electricity operational costs ($/MWhr)
4) Operational changes in terms of the generation mix used to produce the electricity
5) Changes in annual system CO_2 emissions (tons C_2/MWhr)

The main model used to complete this analysis is a Unit Commitment Model (UCM). This is a mixed integer optimization program, commonly used by balancing authorities, to schedule operations in an electricity market [2]. The UCM acts as the balancing tool by determining the least cost generator dispatch schedule to meet the system demand, or *net-demand* which is equal to the electrical demand of the system minus PV generation. Distributed PV refers to PV systems installed on households in a net-metered configuration and thus entering the power system at the distribution level. This configuration essentially means that the grid "sees" the injection of PV power as a reduction in demand, therefore net-demand equals the demand minus the PV generation. To clarify this point, Fig 1 shows a typical daily demand profile of an NC household with the addition of a 2kW PV system. The blue line shows the typical household power usage throughout the day while the red line shows the power produced by a 2kW PV system connected to the household electrical system. The resulting net-demand profile is shown in green.

A second model was created to simulate distributed PV generation within the system at different capacity penetration levels using irradiance and household density data. The PV production Model (PVM) is used as an input to the UCM to calculate the hourly net-demand. The UCM model is run for 365 days to simulate annual system operation. Annual results for six different scenarios are evaluated to determine technical, environmental and economic effects of varying levels of distributed PV penetration on the system.

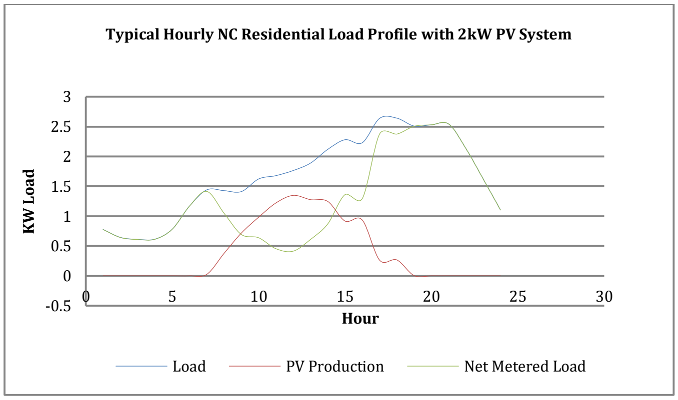

Figure 1: Sample Net-Metered Load Profile of NC Household with 2kW PV System.

1.1 The DEC and PEC Balancing Authority Region

In July 2nd 2012 DEC and PEC merged creating the largest regulated utility in the US encompassing most of North and South Carolina [4]. Figure 2 shows the territory now controlled by the DEC and PEC balancing authority regions [5].

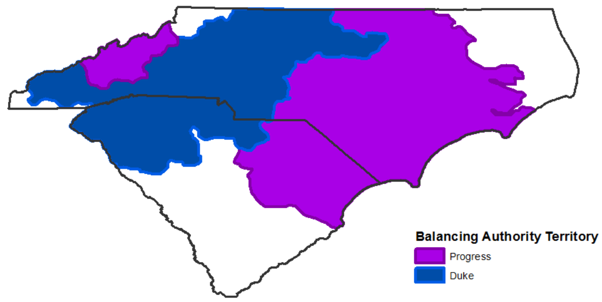

Figure 2: Duke Energy Carolinas and Progress Energy Carolinas Balancing Authority Regions

This region was selected because North Carolina, although not known for high levels of solar irradiation, ranked 4th in the nation as of 2013 for installed solar energy capacity totaling 592MW [6]. This boom in the solar industry can be attributed to the Renewable Energy Portfolio Standards (REPS) that the state of North Carolina passed in 2007. The standard requires investor-owned utilities to supply 12.5% of its retail electricity sales by 2021 from renewable energy sources and energy efficiency methods. These sources include technologies such as wind, solar, hydro, bio-gas and other means such as energy efficiency and demand reduction [7].

Additionally this region is an interesting test case because unlike other states with high levels of installed PV capacity, such as California and Arizona, the DEC & PEC region has a significant amount of "must run" base-load nuclear generation. Figure 3a and 3b show the joint capacity mix and energy production by fuel type and technology for the DEC and PEC regions in 2014 [5]. It can be seen that nuclear generation accounts for 25% of the total generation capacity, and in terms of energy production nuclear is projected to provide 50% of the energy to the system [5].

In the paper "Evaluating the limits of solar photovoltaics (PV) in traditional electric power system" thresholds set by “must run” generators such as large coal and nuclear plants are examined [8]. This study highlights that in periods such as Fall and Spring, where demand is relatively low and PV production is high, net-demand falls below the base-load generation causing excess generation to exist in the system [8]. This occurs because “must run” generators are unable to turn off or ramp down in a timely fashion. When the net-demand crosses this threshold the PV generation causes a system imbalance due to the over-generation on the system. Due to the high amount of nuclear generation on the DEC/PEC system we would expect to find such a base-load threshold for this region.

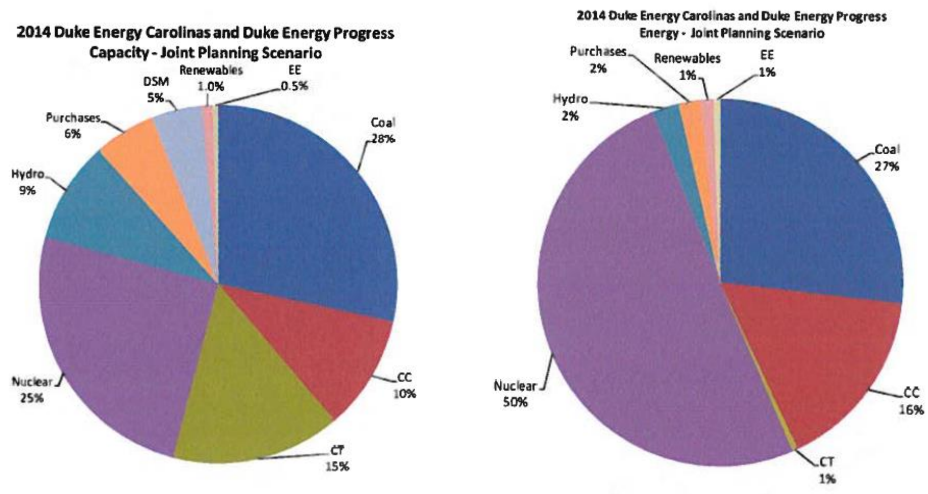

Figure 3: Duke and Progress capacity by fuel type and technology in 2014. 3b Duke and Progress Energy by fuel type and technology in 2014

1.2 PREVIOUS INTEGRATION STUDIES

DEC and PEC have not completed their own integration studies, however Crossborder Energy performed a cost-benefit analysis of net-metered PV generation in North Carolina in 2013 [9]. Their analysis concluded that if utilities were to add 400MW of wholesale solar and 100MW of net-metered PV generation to the system there would be a $26 million per year benefit for rate paying customers [9]. While important, this study focused only on the economics, and considered a PV penetration that is fairly small compared to projected future installations in the region and hence, it the neglected to examine the technical constraints that would arise with higher PV penetrations. To add perspective, the addition of 500MW of PV capacity translates to an annual PV penetration of less than 0.5% in terms of 2005 demand. DEC and PEC, in their Integrated Resource Plan (IRP), project the total of utility and non-utility PV installations to reach 5000MW by the year 2028 in their base case scenario, and 6774MW in their Environmental Focus Case [5] [10]. This translates to annual energy penetration levels of approximately 2.5% and 3.4% in terms of 2005 demand.

Other balancing authorities including PJM and CAISO have conducted their own integration studies examining the technical limits of renewable energy integration. PJM's most recent 2014 integration study, which considered wind and solar penetration scenarios up to 30%, concluded that "no insurmountable operating issues were uncovered" and found that minimal curtailment of renewable sources would be needed. They also noted that the integration would result in lower fuel and O&M costs, however the procurement of additional reserves would be required to handle the additional uncertainty and variability of the renewable resources, and there would be an increase in the cycling of thermal generators [11]. CAISO's study of a 50% renewable integration level found that at a 33% penetration level, over-generation issues caused by the integration of renewable energy challenged the balance of the system [12]. To put these percentages in perspective the two leaders in renewable energy production, Germany and Spain, have achieved 21.9% (4.5% solar) and 24% (4% solar) of renewable energy penetration as of 2012 [12]. Most of the studies conducted by balancing authorities use optimization dispatch models however their methods and data are proprietary and are conducted using system parameters unique to their region.

Larger scale integration studies have been completed such as the Western Wind and Solar Integration Study (WWSIS) in 2010 and the Eastern Wind Integration Transmission Study (EWITS) in 2011 which looked at the impacts of integration levels of 11-35% on the entire western and eastern regions of the US [1]. These studies indicate that penetration levels of 25% to 35% are technically feasible with upgrades in transmission infrastructure and some system operational changes. Additionally the studies indicate that the costs of integration are manageable because of the overall savings in fuel costs which were estimated at a maximum saving of 40% for the WWSIS study and 35% for the EWITS study. Furthermore, these studies found the following strategies would help ease the integration of higher levels of renewable resources: expansion of balancing authorities to increase generator diversity and geographic smoothing effects of renewable sources, higher frequency of generator dispatch, advanced forecasting methods, and increased system flexibility including demand response techniques. Although these studies are technically rigorous, the fact that they look at the entire Eastern and Western regions of the US gives them limited insight on the effects of smaller portions of the grid.

2. METHODS

Figure 4 describes the modeling infrastructure used in this study. At the core of the model is the UCM which schedules generating units to balance the system supply (generation) and net-demand at the lowest cost possible. The main inputs to the UCM model are the test grid parameters which include 1) net-demand 2) generator parameters and 3) system parameters. The PVM is an input to the net-demand. The UCM outputs an hourly generator dispatch schedule and a daily operation cost figure. Other outputs include generator level hourly information such as: status (on/off), generation level (MW), spinning reserves (MW), start-up/shut-down events and system error flags indicating a system imbalance at a specific hour. Annual statistics such as system costs and CO_2 emissions are calculated from this report. The model and simulation is explained in more detail in the sections that follow.

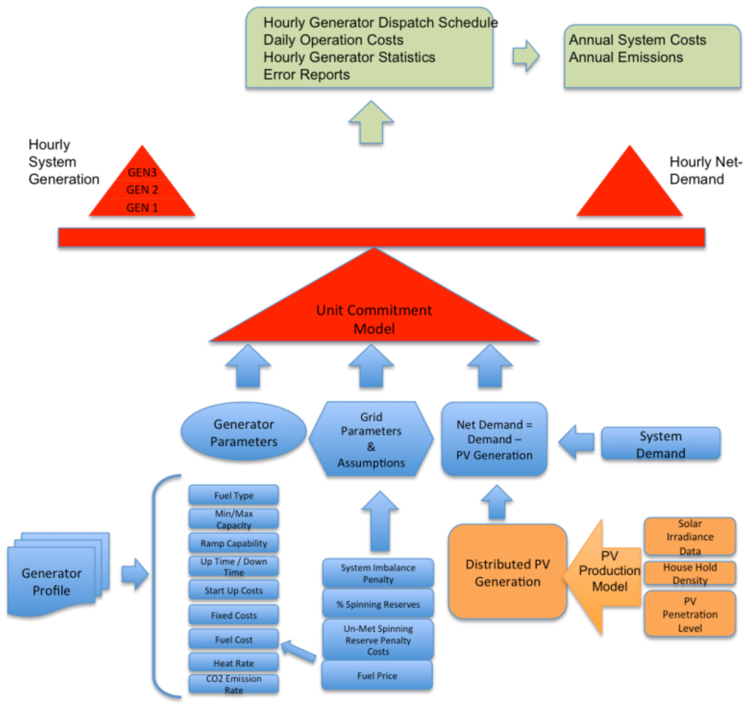

Figure 4: Modeling schematic. PV production model components are shown in orange, test system parameters are shown in blue, the unit commitment model components are shown in red, and model outputs are shown in green.

2.1 Test System Parameters

The test system parameters define the inputs to the UCM model and were chosen to replicate the grid characteristics of the DEC and DEP regions. The system generation capacity and demand were scaled to 10% of their original value to reduce modeling parameters and computation time. The three main components including net-demand, generator parameters, and grid modeling parameters assumptions are discussed in detail in the following sections

2.1.1 Net-Demand

As indicated in the introduction, net-demand refers to the system demand minus the PV production. Due to this relationship, it was important to find both electrical demand data and irradiance data (the key element of PV production) from the same year. Additionally it was important to find a dataset that had spatially distributed irradiance data. Studies such as [1], [13] and [14] confirm that there exists a significant decrease in variability when looking at the average of multiple geographically dispersed sites in comparison to the variability at a single site. For example [14] compared the variability of irradiance between a single site and the average of four sites in Colorado, concluding a significant smoothing effect when the irradiance was averaged. This geographic smoothing effect can relieve some of the generator ramping capability needed to handle the variations in system-wide PV production.

For this reason a gridded dataset from the State University of New York at Albany (SUNY), with a 10km by 10km cell resolution, containing modeled hourly Global Horizontal Irradiance (GHI) values was chosen to capture this spatial variation of irradiance. The National Solar Radiation Database distributes this dataset at no fee for years 1998 to 2005 and the year 2005 was chosen as a representative year [15].

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. It is recognized that solar irradiance can fluctuate instantaneously and therefore higher frequency irradiance data (5 min or 1 min) is preferred [13]. High frequency data was unavailable for this study, however the SUNY dataset estimates GHI values on the hour capturing more variability than an average hourly irradiance values [16]. Quantification of the spatial and temporal variation of GHI values can be determined from the National Solar Radiation Database

Matching hourly 2005 demand data was obtained from FERC Form 714 – Annual Electric Balancing Authority Area and Planning Reports [17]. This data, submitted by DEC and PEC, was aggregated to represent the total system-wide hourly electrical generation. Although this data provides the total system generation, which may include energy exports to adjacent regions, for this study we assume that all electricity is consumed within the region representing the total demand for 2005.

The following section is a description of the PV production model used to calculate net-demand.

2.1.1.1 PV Production Model

Solar irradiance, measured in Watts per square meter (W/m^2), is the main driver of PV production. Using GIS ArcMap, the 10km by 10km grid defined by the SUNY dataset was overlaid with a GIS shapefile containing household census data [18]. The number of homes contained within each of the SUNY gridded cells was aggregated. The resulting gridded data set showing the aggregated number of households in each cell is shown in Figure 5. The vast majority (71%) of US households in 2005 were classified as Single-

Family Detached or Single-Family Attached [19]. For this study we assumed that 100% household units had the roof surface to accommodate a small PV system.

Using this new merged gridded data set, the PV production model determines the hourly output of each grid cell based on the number of households and the PV penetration level. The penetration level is defined as the percentage of total annual energy generated by the distributed PV systems relative to the total annual energy consumed within the system. To put this into perspective Table 1 describes the penetration level as a percentage of households with a 3kW PV system, which is made of 12, 3ft by 5ft PV modules rated at 250W each. All the cells in the area are then aggregated to find the total system-wide hourly PV production. The aggregate capacity of the PV systems can be varied to simulate different annual energy penetration levels.

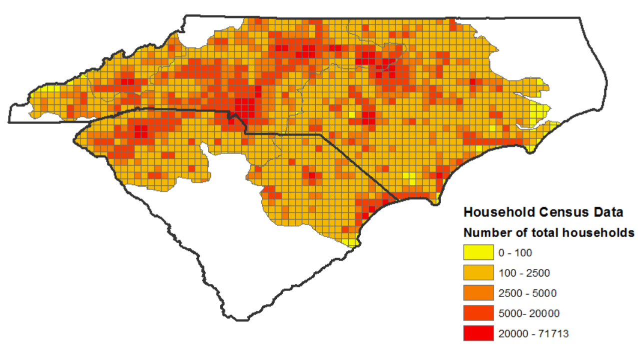

Figure 5: DEC and PEC regions showing household density contained within the 10 by 10km grids defined by the SUNY irradiance dataset.

Table 1: PV penetration levels in reference to residences with 3kW PV systems.

% Annual Energy Penetration	% Households with 3kW PV System	Total System MW of Name-Plate Rated PV Capacity	Total TEST System MW of Name-Plate Rated PV Capacity
0.8%	7%	1,224	122
1.6%	13%	2,448	245
2.4%	20%	3,672	367
3.3%	27%	4,896	490
4.1%	33%	6,120	612
4.9%	40%	7,344	734
5.7%	47%	8,568	857
6.5%	53%	9,792	979
7.3%	60%	11,016	1,102
8.1%	67%	12,240	1,224
8.9%	73%	13,464	1,346
9.8%	80%	14,687	1,469
10.6%	87%	15,911	1,591
11.4%	93%	17,135	1,714
12.2%	100%	18,359	1,836
13.0%	107%	19,583	1,958
13.8%	113%	20,807	2,081
14.6%	120%	22,031	2,203

PV module nameplate capacity is rated at standard test conditions, 1000 W/m^2. Actual output is approximately proportional to the amount of irradiance hitting the tilted surface. The total system output is also de-rated to 77%, based on the default value used in PV Watts for loss factors such as soiling of the modules, wiring losses, inverter losses, module mismatch etc. [20]. Therefore PV generation, $GenPV$, measured in Watts can be estimated by equation 1,

$$GenPV = .77 \times pv_c \left(\frac{I_m}{1000\ {}^{W}/_{m^2}}\right) \qquad (1)$$

Where pv_c (W) is the nameplate PV capacity and I_m (W/m^2) is the direct irradiance hitting the tilted module surface.

The following series of equations adapted from [21] are used to determine the direct irradiance hitting the tilted module surface based on the GHI and the position of the sun relative to the tilted module. This calculation was completed for each grid cell with a specific GHI level, longitude and latitude for each hour of the day throughout the year. Table 2 defines the variables and terms used in the following solar calculations.

Table 2: PV Production Model variables and definitions.

Symbol	Description	Definition	Units
GenPV	PV Generation	The amount of electricity produced from a PV system with rated capacity of pv_c at an irradiance level of I_m	W
I_m	Irradiance on tilted module surface	The portion of the GHI that is normal to the tilted module	W/m^2
pv_c	Name Plate PV Capacity [W]	The name plate capacity of the PV system at test conditions of 1000 W/m^2	W
GHI	Global Horizontal Irradiance	The total irradiance reaching a surface horizontal to the surface of the earth	W/m^2
θ_z	Solar Zenith Angle	The position of the sun's elevation relative to being directly overhead which is the compliment of the solar elevation angle	Degrees
θ	Angle of Incidence	The angle between the sunlight rays incident to module and normal to the tilted module	Degrees
β	Module Tilt Angle	The angle in which the module is tilted	Degrees
γ	Module Azimuth Angle	The module orientation relative to 180 degree south.	Degrees
γ_s	Solar Azimuth Angle	The sun's orientation relative to 180 south	Degrees
δ	Solar Declination Angle	The angle, which varies seasonally due to the earth's tilted axis, between the rays of the sun and the equatorial plane.	Degrees
L	Latitude		Degrees
DOY	Day of Year	The day of the year from 1 to 365	Days
HA	Hour Angle	Angular measurement of time	Degrees
x	Constant	A constant used in the equation of time	None
EoT	Equation of Time	A formula used to account for the earth's orbit and earth's tilt	None
Solar Time	Solar Time	The local time in terms of the position of the sun in terms of a 24 hour day (1440 mins) corrected for time zones	Hours

The direct irradiance normal to the tilted module surface can be estimated from the GHI as follows:

$$I_m = \frac{GHI}{cos\theta_z} \, cos\theta \qquad (2)$$

where θ_z, the solar zenith angle, and θ, the angle of incidence, are defined by equation 3 and 4 respectively.

$$\theta = \ cos^{-1}(cos\theta_z cos\beta \ + sin\theta_z sin\beta \cos(\gamma_s - \gamma)) \qquad (3)$$

$$\cos\theta_z = cosL \ cos\delta \ cosHA + sinL \ sin\delta \qquad (4)$$

L is the latitude of the gridded cell, β is the module tilt angle, γ is the module azimuth angle. For our study the module tilt angle β was set to 25 degrees to represent a module located on a tilted roof surface. The module azimuth angle γ is assumed to be 180 degrees or facing directly south which is the optimal orientation for solar exposure in the northern hemisphere. See Table 6 in Appendix A for performance adjustment values based on different combinations of module tilt and orientation. The solar azimuth angle γ_s, declination angle δ, and hour angle HA are calculated using the equations 5-10. The declination angle is determined by the Day of the year DOY.

$$\delta = 23.45° \ sin\left[\frac{DOY+284}{365} \times \ 360°\right] \qquad (5)$$

The solar azimuth angle, γ_s, is calculated from the following equation:

$$cos \ \gamma_s \ = \frac{sin(90-\theta_z)\sin L - sin\delta}{\cos(90-\theta_z)cosL} \qquad (6)$$

The hour angle is determined by equation 7, where solar time is a function of longitude, time zone, hour of the day and the Equation of Time (EoT), and a constant x determined by equations 8-10.

$$\mathrm{HA} = \frac{(Solar\ Time \times 60 - 720)}{4} \qquad (7)$$

$$\text{Solar Time} = hour\ of\ day + \left(\frac{4\ \times (75 - Longitude) + EoT}{60}\right) \qquad (8)$$

$$\mathrm{EoT} = 9.87 \sin(2x) - 7.53 \cos(x) - 1.5 \sin(x) \qquad (9)$$

$$\mathrm{x} = 360 \frac{(DOY - 81)}{365} \qquad (10)$$

The PV production is thus calculated for each gridded cell based on its unique hourly GHI, longitude and latitude. All the cells are added together to get the total hourly PV generation. This hourly PV generation is then subtracted from the demand to create the net-demand for the system.

2.1.2 Generator Profile

The 2012 Emissions & Generation Resource Integrated Database (eGRID), complied by the EPA, contains generator-level data for all generators in the DEC and PEC regions. The total generation capacity of operating generators in the DEC and PEC regions in 2009 according to the eGRID database was 37,557MW and the generator profile by percentage of major fuel type (Coal, Natural Gas, Nuclear, Hydro, Wind, Oil, & Biomass) can be seen in Figure 6 [22]. The eGRID database was used to initially sort and select generators by fuel-type, prime mover (ie steam, combustion turbine, combined cycle), maximum capacity and heat rate.

Once the major characteristics of the generators were defined, a variety of sources were used to quantify the sample generator parameters. The final list of generators used in the test grid scenarios are listed in Table 3. The section below details the methods used for generator selection within each major fuel type.

Coal Generators

A two-dimensional k-means clustering analysis by capacity and heat rate was used to group the original 48 coal generators in eGrid into 4 clusters. This clustering technique uses an algorithm to find cluster centers in which the total distance between the data points belonging to the cluster and the associated cluster center are minimized, thus grouping similar data points into groups [23]. A summary of statistics for the clusters can be found in Table 7 in Appendix A. This was the preferred method to ensure finding representative generators based on two different criteria. The number of generators selected from each group was based on the original capacity distribution within each cluster. Generators were then randomly selected from each cluster and the original characteristics such as capacity, heat-rate and associated CO_2 emissions data defined the major characteristics of the generator selected.

Nuclear Generators

A single nuclear generator of size 1124MW was chosen based on the original 29% of total system capacity. The average maximum capacity and capacity factor of the 13 nuclear plants in the original system was 1021MW and 87% respectively [22]. The nuclear generator in the test system is assumed to serve as a base-load generator operating at 87%, and thus providing a constant base-load generation of 977 MW. The nuclear plant is assumed to have no ramping capabilities and is unable to provide any spinning reserves.

Hydro-Electric Generators

The capacity of the hydro-electric generator, 218MW was chosen based on its original share of 6% of total system capacity. Hydro-electric generators are important to the system because they provide flexibility in terms of their fast ramping capabilities and no limits on minimum up and down times. However, the total amount of energy they can inject into the system is limited to the water supply from reservoirs and streams. Duke Energy documents 2% of annual generation from hydro-electric generation in their 2014 IRP [5]. This percentage was used to estimate a daily energy generation limit of 906 MWhrs from hydro-electric generators.

Natural Gas Combustion Turbines

Similar to the clustering methods used to select coal generators, a clustering analysis using 3 clusters was used to select a sample of Natural Gas Combustion Turbines from the original 76 NGGT generators in the system. A summary of statistics for the clusters can be found in Table 8 in Appendix A.

Natural Gas Combined Cycle Generators

Only 8 combined cycle generators were present in the 2009 eGrid dataset. The most efficient, generator that was placed online in 2003 was chosen.

NEW 2010 -Natural Gas Combined Cycle Generators

The parameters of the new natural gas generators added to the system in Scenario E where selected using figures from an NREL report regarding costs and performance assumptions [24]. The capacity and heat rate were determined by using the average plant size and heat rate and their associated means and standard deviations.

2.1.3 Generator Operational Parameters

Once the major characteristics of the generators (Type, Max Capacity, Heat-Rate) were selected using the eGRID database, additional operational parameters were defined. A generator dispatch study conducted by The Federal Energy Regulatory Commission (FERC) was the source used to determine minimum run/down times, start-up costs, and minimum economic capacity operational levels [22]. In 2012 FERC created its own test system for analysis based on the characteristics of the PJM Regional Transmission Organization (RTO). They have published their set of generator parameters based on historical PJM generator performance and bidding data.

The minimum run time, measured in hours, is defined by the minimum time that once started up, the generator must run before shutting down. Minimum down time is the amount of time that once turned off, the generator must remain off before starting back up. In our study the Minimum run/down times for coal and natural gas respectively were 15/9 and 4/3. This is consistent with the majority of the generators in the FERC study. Nuclear plants are assumed to be running constantly and hydro-electric plants have a min run time of 1 hour and min down time of 1 hour which allows them to turn on and off as needed with no restraints.

The minimum economic capacity of a generator is the lowest generation level that the generator can operate economically. Thus the generators in our model cannot operate below this minimum. A trend line was fit to the minimum economic capacity data found in the FERC dataset for each type of generator. The trend lines were used to calculate the minimum economic capacity of each generator based on its maximum capacity.

Generator ramp rates for coal and natural gas generators were obtained from study completed by the International Energy Agency. Ramping capability (MW/hour) for coal generators built before 1960 are estimated to be 36% of their rated maximum capacity. Natural Gas generator ramping capability was estimated in the range of 15-25 MW/Min which translates to 900-1500 MW/hour. Since all our generators are less than 900 MW, all natural gas generators have a ramping rate equal to their rated maximum capacity [26].

2.1.4 Generator Cost Parameters

The cost of producing electricity in our model includes the fixed costs, start-up costs, and marginal fuel costs for generation and providing spinning reserves. Fixed costs represent the cost to maintain and operate the generators even when they are not producing electricity. This data was obtained by a report by NREL which provided an estimate of fixed costs by $/kW/year by generator type [24]. Each time a generator is scheduled to start-up a cost is incurred due to the fuel and electricity needed to crank the generator motor. Start-up costs were obtained by comparison to generators in the FERC Unit Commitment Study with similar characteristics in terms of prime mover, fuel type, heat rate and capacity. Marginal fuel costs for coal and natural gas generators were determined by the generator heat rate and the fuel source prices.

The dispatch of generators is highly affected by the price ratio of natural gas to coal [27]. As described in the following scenario analysis section of this paper, three fuel prices for coal and natural gases are used in the study to represent extreme and average price scenarios. A variable fuel price of $7.50/MWh is used for Nuclear Generation [28]. The marginal fuel costs for hydro-electric generators are assumed to be $0.

Table 3: Generators parameters used in test system.

Generic Plant Name	Prime Mover	Max Capacity (MW)	Min Economic Capacity (MW)	Heat Rate (Btu/kWhr)	Ramp Rate (MW/hr)	Min RunTime (Hr)	Min Down Time (Hr)	Fixed Cost ($)	Startup Costs ($)	CO2 Emission rate (lb/MWh)	Year Online
COAL1	ST	113	33	10056	41	15	9	472	1483	2062	1969
COAL2	ST	657	265	9890	266	15	9	2759	23524	2029	1966
COAL3	ST	188	61	9495	68	15	9	789	2200	1948	1923
COAL4	ST	275	95	10528	99	15	9	1155	6543	2160	1957
COAL5	ST	70	19	12097	25	15	9	294	2426	2479	1949
COAL6	ST	75	21	10240	27	15	9	315	2952	1923	1968
NGCC1	CC	199	108	7751	199	4	3	301	7269	922	2003
NGGT1	GT	28	15	17923	28	4	3	22	2663	2097	1976
NGGT2	GT	34	18	10923	34	4	3	27	1551	2240	1969
NGGT3	GT	41	22	10749	41	4	3	32	1680	2193	2007
NGGT4	GT	57	31	10452	57	4	3	45	1949	1262	2007
NGGT5	GT	110	59	37125	110	4	3	86	36818	4652	1995
NGGT6	GT	110	59	37125	110	4	3	86	36818	4652	1995
NGGT7	GT	100	54	123884	100	4	3	78	5509	14848	2002
NGGT8	GT	100	54	123884	100	4	3	78	5509	14848	2002
NGGT9	GT	212	115	11412	212	4	3	166	8826	1357	2002
HYDRO	HY	218	0	-	218	1	1	373	400	0	
NUC1	ST	1124	-								
NEWNGGC1	CC	371	137	6761	371	4	3	559	6446	869	
NEWNGGC2	CC	295	117	7114	295	4	3	445	8118	869	

NEWNGGC3	CC	246	95	6754	246	4	3	371	6226	869

2.2 Unit Commitment Model (UCM)

The UCM uses the system parameters discussed above to determine the hourly generation of each generator. A Bass Connections Project Team called Modeling Tools for Energy Systems Analysis (MOTESA) at Duke University originally built the UCM model using IBM's ILOG CPLEX Optimization Studio. This model was modified in 2 specific ways for this analysis. First, constraints were added to the model to incorporate the unique properties of Hydro-Electric generators. Next the simulation of the model was modified such that iterations were "nested" to incorporate perfect foresight 8 hours into the future. For example, a single iteration of the model optimizes over time intervals 1-32 but only records the output for intervals 1- 24. On the second iteration, the model optimizes over time intervals 25-56 and records the output for intervals 25-48. This modification was made to the model to avoid optimization result mismatches from one 24 hour period to the next due to limited foresight.

2.2.1 System Parameters and Assumptions

The following assumptions regarding transmission, security requirements, foresight and forecasting are made within the model. The model does not incorporate transmission and thus all generation flows freely throughout the system as if supplying all the demand at single bus bar. PV generation occurs at the distribution level such that the system only actually *feels* the effect of a net load (Demand –PV). Due to this configuration it is most likely that transmission congestion will be eased by high penetrations of PV during high demand times, however this is not taken into account within the model.

The security requirements of the system are set such that over-generation and under-generation are penalized at a rate of $10,000/MWhr. Due to limited public information penalty values for loss of load in the Duke and Progress region this rate was used which is consistent with modeling assumptions in the unit commitment study completed by FERC based on the PJM region [25]. Additionally for security purposes power generation reserves must be equal to 15% of the total demand and must be scheduled in the form of spinning reserves. A penalty of $1,000/MWhr is incurred if this requirement is not met. It is important to note that system imbalances in the form of over-generation and under-generation pose a significant risk to the stability of the electrical system. In this model we are assuming that these imbalances do not cause complete system failure and can be addressed operationally through manual generator adjustments, curtailment, demand response or other measures.

2.2.2 MATHEMATICAL FORMULATION

Table 4 contains definitions for all the indices, parameters, and decision variables used in the following optimization formulation. A verbal explanation of the objective function and constraints is provided after the mathematical formulation.

Table 4: Unit Commitment Model Optimization indices, parameters, and decision variables.

Symbol	Description
	Indices
u	Dispatchable generator unit, $u \in 1..T$
t	time interval hour, $t \in 0..T$
n	time interval index used for minimum up and downtime requirements, $n \in t..T$
	Parameters
T	Number of intervals in time horizon
U	Number of dispatchable generators in the system
Demand	*System* demand in interval *t* [MW]
SpinReqt	Quantity of spinning reserve required in interval *t* [MW]
UnderGenPen	System-wide under generation penalty [$/MWh]
SRScarcityPen	System-wide spinning reserve shortage penalty [$/MWh]
MCu:	Marginal Cost of operating dispatchable unit *u* [$/MWh]
SRCu	Cost of spinning reserve provided by unit *u* [$/MWh]
NLCu	No load cost (fixed operation cost) of operating unit *u* [$/interval]
StartCu	Cost of starting unit u [$]
Commitu,t	Commitment status of unit *u* in interval *t* (only a parameter in economic dispatch
MaxGenu	Maximum generation of unit *u* [MW]
MinGenu	Minimum generation of unit *u* [MW]
PosRampRateu	Maximum ramp-up rate of generator *u* [MW/minute]
NegRampRateu	Maximum ramp-down rate of generator *u* [MW/minute]
InitMinUpu	Number of intervals generator *u* must be up at the start of the optimization period
InitMinDownu	Number of intervals generator *u* must be down at the start of the optimization period due to its initial downtime [intervals]
MinUTu	Minimum uptime of unit *u* [intervals]
MinDTu	Minimum downtime of unit *u* [intervals]
InitMinUpu	Number of intervals generator *u* must be up at the start of the optimization period
Commit0u	Commitment status of unit *u* at end of previous time horizon [binary]
Gen0u	Generation level of unit *u* at end of previous time horizon [MW]
SR0u	Spinning reserve provided by unit *u* at end of previous time horizon [MW]
	Decision Variables
Genu,t:	*Average power generation of unit u in interval t [MW]*
SRu,t	*Spinning reserve provided by unit u in interval t [MW]*
Commitu,t:	*Commitment status of unit u in interval t (only a decision variable in unit commitment models) [binary]*
StartCostu,t	*Startup cost of unit u in interval t [$]*
OverGent	*Surplus of generation over demand in interval t [MW]*
UnderGent	*Shortage of generation below demand in interval t [MW]*
UnmetSRt	*Shortage of spinning reserve below requirement in interval t [MW*

Minimize the objective function *z:*

$$z = \sum_{t=1}^{T} \left(\sum_{u=1}^{U} (Gen_{u,t} \times MC_u + SR_{u,T} \times SRC_u + Commit_{u,t} \times NLC_u + StartCost_{u,t}) + OverGen_t \times OverGenPen + UnderGen_t \times UnderGenPen + UnmetSR_t \times SRScarcityPen \right)$$

Such that:

1. $Commit_{u,0} = Commit0_u \quad \forall u$
2. $Gen_{u,0} = Gen0_u \quad \forall u$
3. $SR_{u,0} = SR0_u \quad \forall u$
4. $\sum_{u=1}^{U} Gen_{u,t} + UnderGen_t - OverGen_t = FDemand_t \quad \forall\, t\ \in 1..T$
5. $StartCost_{u,t}\ \geq StartCost_{u,t} \times \left(Commit_{u,t} - Commit_{u,t-1}\right) \forall u, \forall\, t \in 1..T$
6. $Gen_{u,t} + SR_{u,t} \leq MaxGen_u \times Commit_{u,t} \quad \forall u, \forall t\ \in 1..T$
7. $Gen_{u,t} \geq MinGen_u \times Commit_{u,t} \quad \forall u, \forall t\ \in 1..T$
8. $Gen_{u,t} - Gen_{u,t-1}\ \leq PosRampRate_u \quad \forall u, \forall t\ \in 1..T$
9. $Gen_{u,t} + Gen_{u,t-1}\ \leq NegRampRate_u \quad \forall u, \forall t\ \in 1..T$
10. $SRes_{u,t} \leq PosRampRate_u \quad \forall u, \forall t\ \in 1..T$
11. $\sum_{t=8}^{19}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) \leq MaxEnergy \quad \forall\, u$
12. $\sum_{t=1}^{7}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) = 0 \quad \forall\, u$
13. $\sum_{t=20}^{32}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) = 0 \quad \forall\, u$
14. $\sum_{u=1}^{InitMinUp_u}\left(1 - Commit_{u,t}\right) = 0 \quad \forall\, u$
15. $\sum_{n=t}^{t+MinUT_u-1}\left(Commit_{u,n} \geq MinUT_u \times \left(Commit_{u,t} - Commit_{u,t-1}\right)\right) = 0 \quad \forall\, u, \forall t\ \in \{InitMinUp_u + 1, T - MinUT_u + 1\}$

16. $\sum_{n=t}^{T}\left(Commit_{u,n}-\left(Commit_{u,t}-Commit_{u,t-1}\right)\right)\geq 0 \quad \forall\, u, \forall t \ \in \{\, T-MinUT_u+2, T\}$
17. $\sum_{u=1}^{InitMinDown_u}\left(Commit_{u,t}\right)=0 \quad \forall\, u$
18. $\sum_{n=t}^{t+MinDT_u-1}\left((1-Commit_{u,n})\geq MinDT_u\times\left(Commit_{u,t-1}-Commit_{u,t}\right)\right)=0 \quad \forall\, u, \forall t \ \in \{InitMinDown_u+1, T-MinDT_u+1\}$
19. $\sum_{n=t}^{T}\left((1-Commit_{u,n})-\left(Commit_{u,t-1}-Commit_{u,t}\right)\right)\geq 0 \quad \forall\, u, \forall t \ \in \{\, T-MinDT_u+2, T\}$
20. $Gen_{u,t}, SR_{u,t}, StartCost_{u,t}, OverGen_t, UnderGen_t, UnmetSR_t \geq 0 \quad \forall u, t$

The objective function minimizes the total costs for running the generators (generation fuel costs, spinning reserve fuel costs, start-up costs, and fixed no load costs) as well as penalty costs (over-generation, under-generation, un-met spinning reserves) over a 32 hour time horizon subject to the constraints.

Constraints 1-3 are included to initialize the model and simulation. Constraint 4 ensures that generation always equals demand in each interval, and if it doesn't there exists over or under generation which will incur a penalty cost in the objective function. Constraint 5 assigns a startup cost to the unit in the time interval in which the binary commitment variable switches from 0 to 1, indicating that the unit has turned on. Constraints 6 and 7 ensure that the maximum and minimum generation levels of committed generators are obeyed while constraints 8-10 ensure that the generators are operating within the restrictions of their positive and negative ramp rates. Constraints 11-13 are the additional constraints added specifically to address the energy limited nature of Hydro Electric plants. Constraint 11 limits the total energy that can be supplied by the hydro-electric generator during the hours of 8am to 7pm. This is needed because of the limited supply of water in the reservoirs that can supply the generator each day without draining it completely. The Max Energy constant was found by calculating the estimated daily hydro output, assuming that the annual percent of energy generation for the DEC and DEP region is around 2%. Therefore the Max Energy variable used in the model was 907 MWh. Constraints 12 and 13 restrict generation to only the peak hours of the day. Constraints 15-19 are a series of constraints that guarantee that the minimum-up and -down times are obeyed. The initial minimum-up and -down time variables are calculated in a post-processing calculation at the end of each iteration and are carried over to the next time horizon during the simulation. Finally constraint 20 restricts all the decision variables to be greater than 0.

2.3 Scenario Analysis

The six scenarios are summarized in Table 3. For each scenario the UCM determines the least cost annual hourly dispatch schedule using the available generation capacity. Varying levels of PV penetration for each scenario are added as an input to the UCM by varying the PV capacity in the PV production model and then subtracting this value from the demand to become the net-demand. The UCM is run starting at 0% PV penetration level to increasing levels of PV penetration within each scenario.

Scenarios A, B and C all have a generator capacity mixes aligned with the percentages found in the eGRID 2009 dataset for the DEC and PEC regions and are shown in Figure 6 [22]. The capacity mixes used in the test system are comparable to those found in Figure 3a, however it can be seen that energy purchases, energy efficiency (EE), demand side management (DSM) are not included in the capacity mix for the test system.

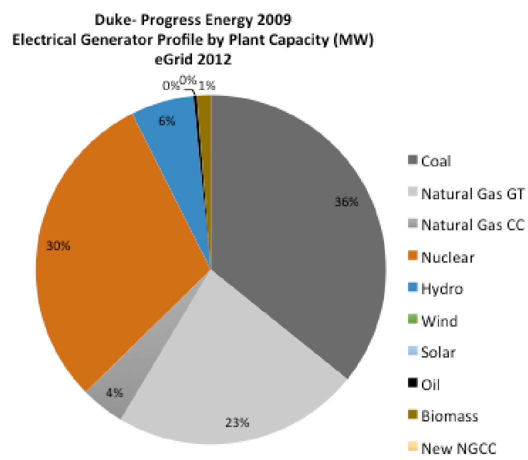

Figure 6: DEC and PEC Generator profile according to eGRID 2009 data.

The fuel prices in scenarios A, B and C are varied to represent low, average, and high ratios of natural gas to coal prices. The ratio between natural gas to coal prices is an important factor because generators are primarily dispatched based on their marginal cost of operation, which is a function of a generator's heat rate and fuel prices. The 5th and 95th percentile of monthly historic natural gas to coal price ratios from years 2000 to 2012 were used as the basis for selection for low and high natural gas to coal price scenarios in A and C. The average coal and natural gas prices from this dataset were used as the fuel prices in scenario B as well as all other scenarios [29].

In scenario D, 25% of the coal capacity is replaced with new efficient natural gas plants. This is a highly likely scenario in light of the US Environmental Protection Agencies proposed plan released June 2, 2014 to reduce greenhouse emissions associated with electricity sector by setting state specific CO_2 reduction goals [30]. This change toward more efficient and lower emission electrical generation is evident in both the DEC and PEC IRPs for the year 2013. PEC reported that a total of 1000MW of coal capacity had been retired as of 2010 and 600MW more are to be retired in the year 2014 [10]. Similarly, DEC reported a total of 1300MW of coal capacity has been retired since 2011. This capacity is mainly being replaced by new natural gas capacity [5]. DEP and DEC report that 3,683MW and 2096MW respectively of new natural gas generation is planned to come online between the years of 2014 and 2028 [5] [10].

Scenario E explores the option of reducing the amount of base-load nuclear generation by 50% and replacing the system capacity with new natural gas plants. This scenario is included to examine the limiting effects of "must-run" generators on PV integration.

Finally, scenario F uses this adjusted capacity mix along with a cost for carbon emissions. The EPA defines the social cost of carbon as the price of future economic damages related to the release of one metric ton of CO_2. A price of $39 per metric ton of CO_2 is used to represent the cost associated with the release of one metric ton of CO_2 in the year 2015 at a discount rate of 3% [31].

Table 5: Summary of Scenario Analysis

Scenario	Capacity Mix: Coal	Nuclear	NGGT	NGCC	Hydro	New-NGCC	Low NG:C Price Ratio $1.95: (NG) $1.22 (Coal)	Average NG:C Price $5.98 (NG): $1.80 (Coal)	High NG:C Price Ration $13.14: (NG) $2.41 (Coal)	Social Cost of Carbon
A	37%	30%	21%	5%	6%	-	x			
B	37%	30%	21%	5%	6%			x		
C	37%	30%	21%	5%	6%	-			x	
D	27%	30%	21%	5%	6%	10%		x		
E	28%	15%	21%	5%	6%	25%		x		
F	28%	30%	21%	5%	6%	10%		x		$39

3. RESULTS

3.1 BASE-LOAD THRESHOLD LIMITATIONS

One of the most notable findings of this study was a defined base-load threshold caused by "must-run" nuclear generation starting at PV penetration levels of 5.7%. The solid line in Figure 7a identifies the "must-run" nuclear base-load threshold for Scenarios A, B, C, D and F. Starting at the 5.7% penetration level, net-demand dips below this threshold in the spring when energy demand is low but solar potential is still high, thus causing excess generation in the system. The existence of this type of limitation was discussed in [8] however here it is quantified for the DEC and PEC balancing authority region. Increased system flexibility such as in scenario E, in which nuclear generation is reduced by 50%, lowers this threshold allowing PV penetrations near 10.6% before reaching the base-load threshold (See Figure 7b).

As

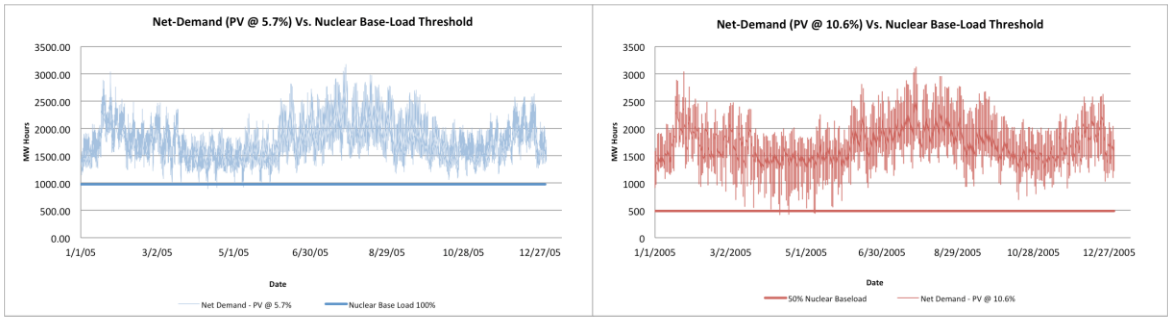

Figure 7: Maximum PV penetration levels for current Nuclear Power Capacity and for a 50% reduction in Nuclear Power Capacity

3.2 System Error Events

In addition to the limiting threshold observed above, other limitations of the system become apparent in the form of *over-generation ramping/shutdown* events and *under-generation ramping/start-up events.* It has been assumed that these types of events can be corrected technically or operationally at a penalty cost of $10,000/MWhr.

Over-generation ramping/shutdown events are observed when net-demand is above the base-load threshold but the system still experiences over-generation. The cause of this type of event can be attributed to the inability of a committed generator to ramp down or shut off when demand decreased over time intervals due to either ramping or minimum up-time constraints of the committed generator.

Under-generation ramping/start-up events are observed when the system experiences under-generation. These events were the rarest type of error because the system had plenty of head-room to turn on generators as needed.

Figure 8 shows both the quantity and magnitude of non-base-load threshold over- and under-generation ramping events. The results indicate that the rate of these types of events increase with the addition of PV penetration due to the increased levels of variability. Although the system is subject to these events, they are relatively small compared to the total system operation. For example 11 none-base load error events, such as in scenarios C and D at penetration levels of 7.3%, translates to 0.1% overall annual system error rate. The validity of the events will be discussed in further detail in the discussion section.

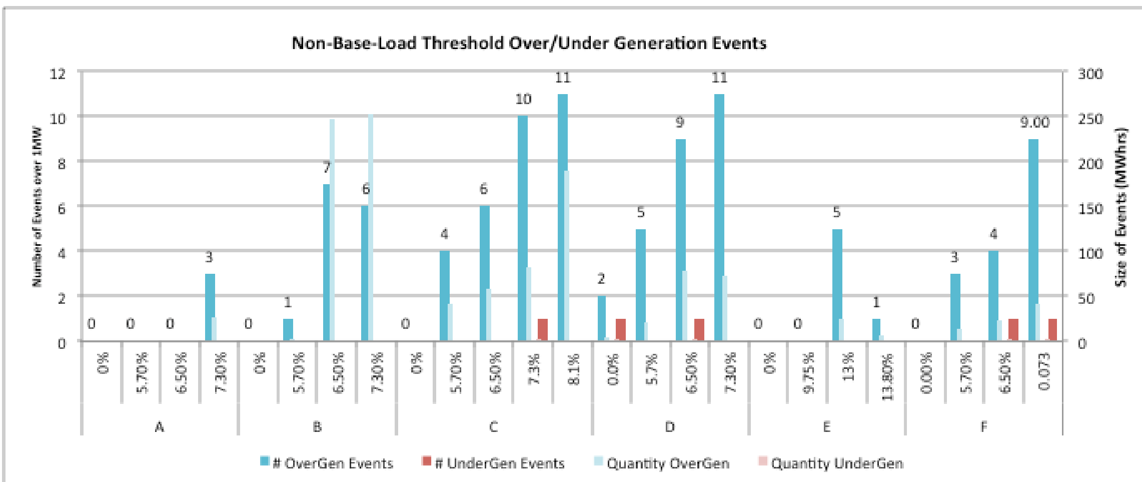

Figure 8: Non-Base-Load Threshold error events in a year

3.3 System Costs

Figure 9 shows the annual operating system costs for each scenario with the generation imbalance penalty costs depicted in red. PV penetration reduced overall system operating costs[1] in all scenarios at penetration levels below the base-load threshold limit. This result makes sense since the operational costs of PV systems are $0 assuming no fuel costs or variable O&M costs. The range of reduction in costs from 0% penetration to 5.7% penetration across scenarios A, B, C, D and F from was $1.31-$2.92 per MWhr, and for E the reduction was $4.30 from 0% to 9.75%.

After reaching base-load threshold however, over-generation penalty costs associated with excess generation begin to significantly increase system costs. Note that this occurs in all scenarios except E at a penetration level of 7.3%, and for E at 13.8%. If the penalty cost was lower more PV could be put on the system before system costs caught up to 0% penetration system cost levels. Alternatively, if the penalty cost was greater, only a few over-generation events could cause the cost of the system increase significantly.

As expected, system costs increased with increasing fuel prices ratios in A, B and C. Also to be expected, the system costs increased in E when low cost nuclear generation is reduced by 50% and in F with the added social cost of carbon.

[1] Capital costs of the PV systems are not factored in because systems are assumed to be customer-owned.

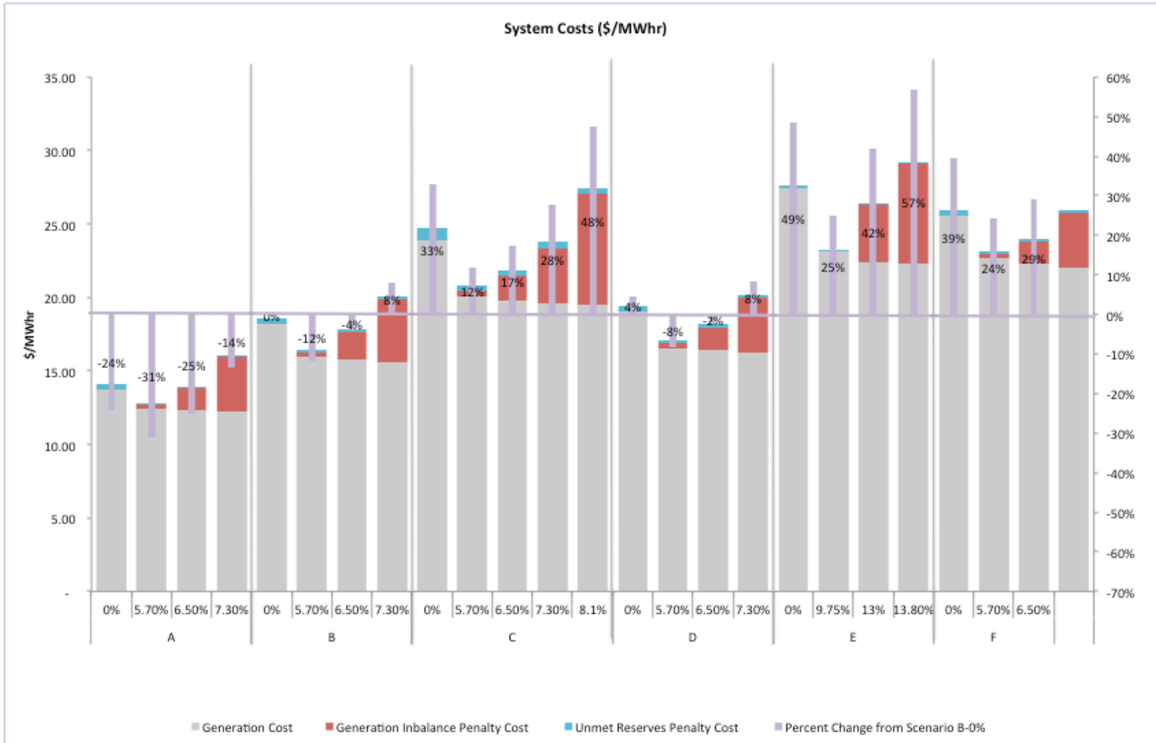

Figure 9: System costs results by scenario. Left axis is measured in $/MWhrs. Right axis measures the percentage difference from scenario B-0%.

Another interesting observation is the increase of penalty costs across scenarios A, B and C at the 5.7% penetration level, which were 0.42, 0.48 and 0.73 $/MWhr respectively.

3.4 Generation Mix

The introduction of PV generation does not equally reduce the operation of all generators in the system as seen in Figure 10, which shows the percentage of annual operation from each type of generator. In all scenarios, PV penetration mainly displaces coal generation. For example the average decrease in coal generation for scenarios A-D at a 5.7% PV penetration level was 4.55% and the decrease in coal generation for scenario E at a 13.8% PV penetration level was 6.8%. This is compared to a decrease of only 0.26% and 0.59% for natural gas combined cycle and natural gas turbine generation in Scenarios A-D. When coal capacity is decreased in scenarios D and F and replaced with new natural gas generators the generation from the older natural gas plants are significantly reduced because of the new generators have a lower marginal cost due to increased efficiency.

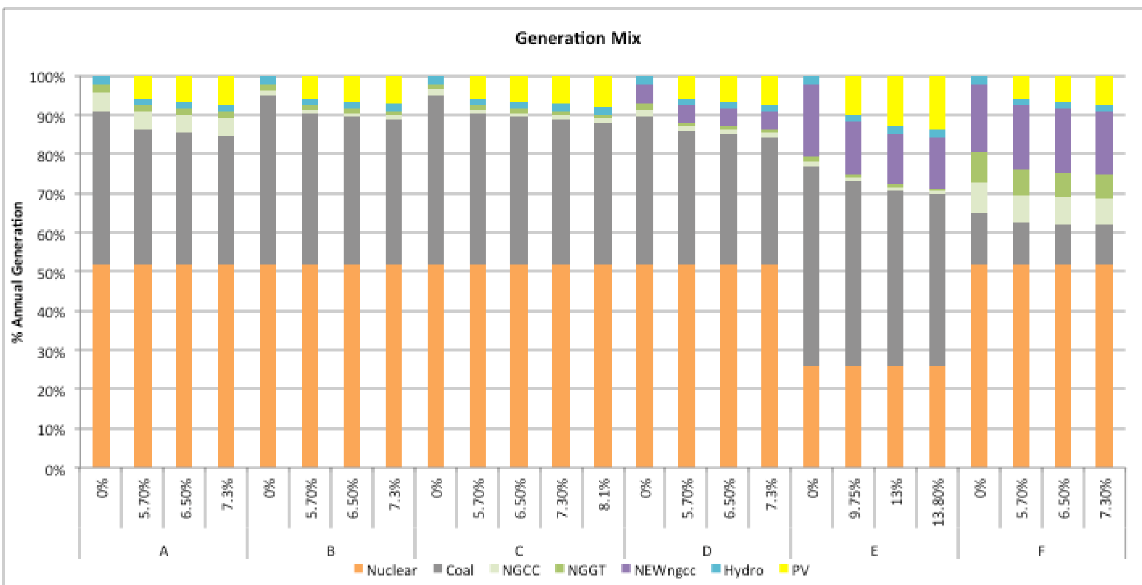

Figure 10: Generation mix by scenario.

In scenario E the reduction in nuclear generation causes an increase in base-load coal generation and new natural gas generation with PV generation reducing coal generation. In scenario F there is a 2.25% reduction in coal generation at 5.7% due to the inclusion of the social cost of carbon.

3.4.1 Revenue Losses

The conventional generation displaced by PV generation has a significant impact on the gross revenues of existing generators showing an average loss of $94 million dollars due to the decreased operation at the 5.7% penetration level. Figure 11 shows the annual displaced revenue for the different PV penetration levels using a electricity price of 10 cents/kWhr. It is evident that coal plants see the largest reduction in revenue. At a penetration level of 5.7% scenarios A, B and C see a loss of approximately $78.9 million dollars and D, E and F see losses of $64.2, $57.1 and $37.1 million dollars respectively. In scenario F, where there is a cost associated with carbon emissions, the losses are more equally distributed between coal and natural gas plants.

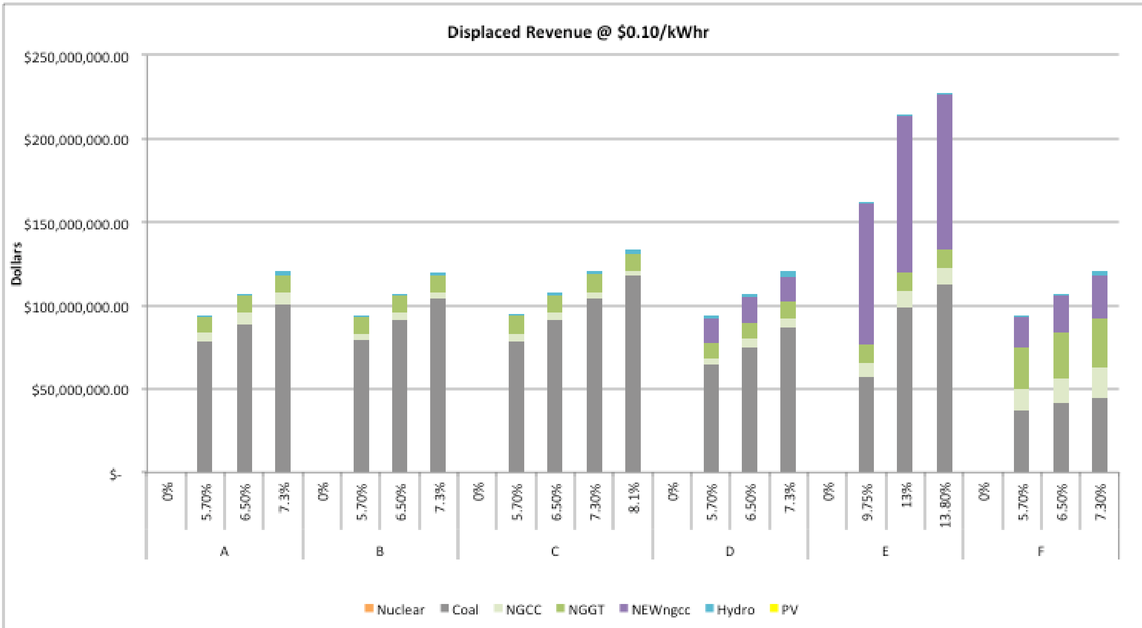

Figure 11: Displaced revenue from increasing levels of PV penetration.

3.5 CO_2 Emissions

As expected Figure 12 shows that CO_2 emissions decrease as PV penetration increases. The results indicated a reduction of .42MT/MWhr (936lbs/MWhr) to .37MT/MWhr (816lbs/MWhr) from the baseline scenario B-0% to B-5.7% indicating a reduction of 13%. Figure 13, however compares system costs with CO_2 emissions in each scenario showing the percentage change from scenario B-0%. This highlights that adding a social cost of carbon in scenario E, is the most effective way to reduce emissions among the scenarios even at 0% PV Penetration level. Although this is also accompanied by large increases in system costs ranging from 20-40%.

When looking at the changes due to PV in scenario B-5.7% the system costs drop by 12% and emissions drop by 13%. Additionally in scenario D-5.7% the system cost reduction is only 8%, due to the use of more natural gas, although there are deeper CO_2 emissions reduction at 18%.

Another interesting finding is that removing 50% nuclear generation from the system, such as in scenario E, which allows for potentially higher levels of PV penetration, actually increases both system costs and CO_2 emissions.

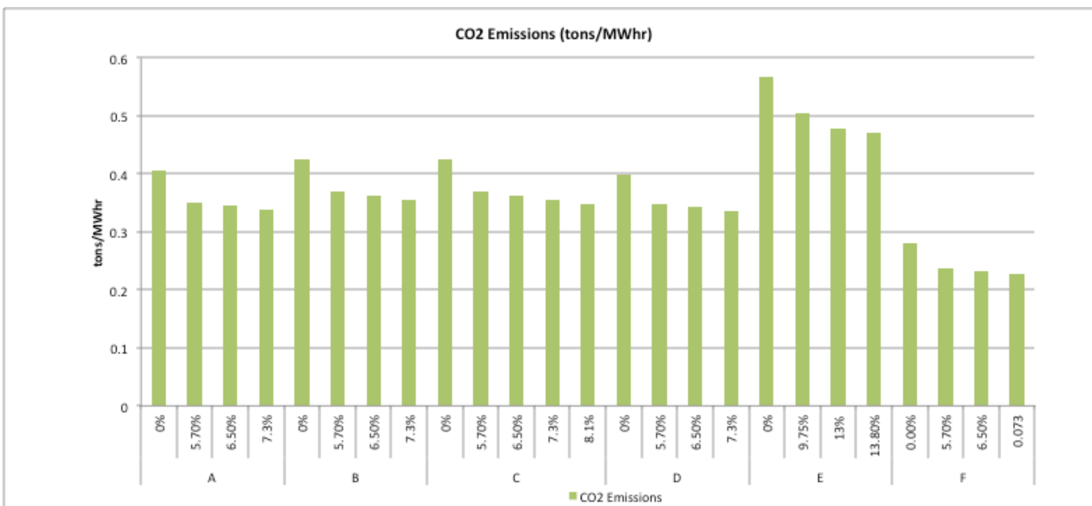

Figure 12: CO_2 Emissions by scenario

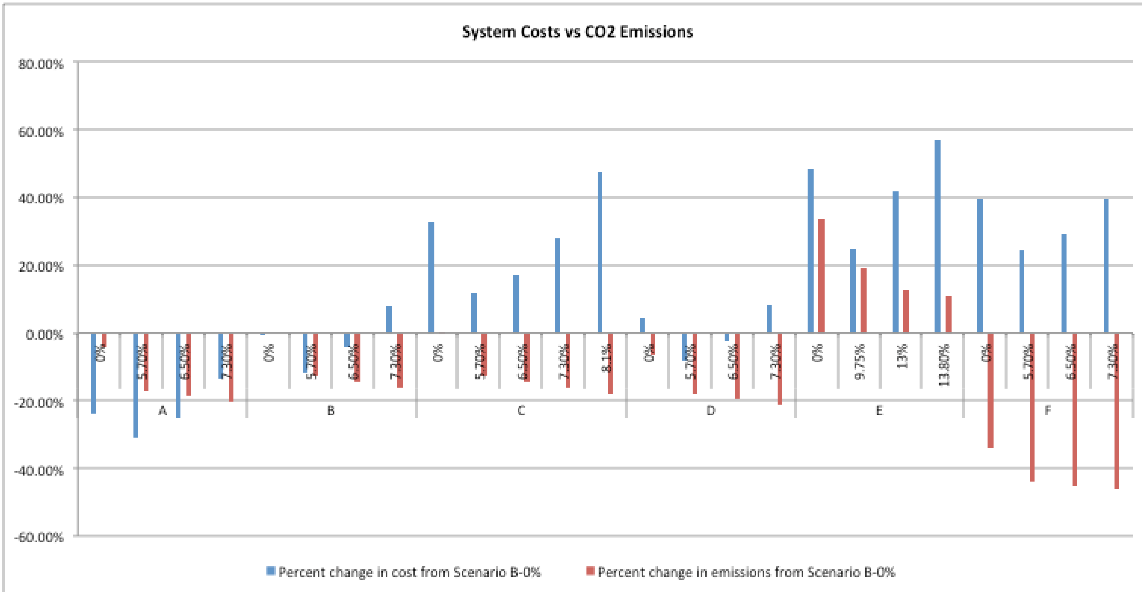

Figure 13: A comparison of percentage changes in cost and emissions from scenario B-0%

4. DISCUSSION

It is recognized that the results found in this study are sensitive to the inputs and assumptions used in the model. One of the most important inputs to the overall model is the PV generation simulated by the PV Production Model. The results of the PVM show an aggregated production of 1097MWhrs/year for 1 MW of installed PV capacity. The production calculated by NREL's PV Watts Calculator for 1 MW located in Charlotte, NC (centrally located in the region) at a 25 degree tilt and 180 degree orientation is 1310MWhrs/year [20]. NREL's PV watts calculator uses irradiance and temperature data from a typical meterologic year and therefore one would not expect these numbers to be identical. Additionally NREL's production data accounts for only a single location. With these differences taken into account the PVM appears to provide a good estimate of total PV production.

The lack of high frequency irradiance data, limited the PVPM from capturing intra-hour variability. This has the potential to underestimate ramping error events by lack of visibility to variability at short time scales. Additionally, it was assumed that the forecast for PV production is a 100% accurate, meaning that there was zero uncertainty surrounding the scheduling of the generators. This is not the case in real world operations, since PV production is highly dependent on weather, which itself not 100% predictable. Uncertainty surrounding PV production has the potential to raise the quantity and magnitude of ramping errors in the system. Forecasting for PV system output is a new research area and [32] summarizes the current techniques being used to examine this issue. PV forecasting has not been yet widely adopted into actual power operations, but will become more and more important as a higher capacity of PV is integrated onto the system.

One of the principle findings was that PV generation is limited due to the base-load nuclear generation starting at penetration levels of 5.7%. The presence of this type of limitation is verified in [8], however the threshold found for the DEC and PEC regions could be underestimated due to the assumption that the nuclear generation is running at a constant capacity factor of 87% with no ability to ramp up or down. In reality, nuclear generation does have some ramping capability, and could be potentially ramped up or down seasonally in the Spring and Fall or daily to accommodate greater levels of PV generation. As mentioned in the introduction, the CAISO integration study found a similar threshold at 33% however this includes a mixture of all renewable energy resources. The higher threshold in the CAISO region is due to the fact that CAISO has more flexibility in its capacity mix (22% renewables, 3.5% nuclear, 0.7% coal and 60.8% natural gas) [33].

Additionally it is important to note that this finding is based on 2005 demand levels. There has actually been a 5% decrease in electrical demand in North Carolina and South Carolina from 2005 to 2013 which may further limit penetration levels due to base-load generation [34].

Other limits to the system appear in the form of ramping and shutdown errors due to either ramping or minimum up-time/down-time constraints of the committed generator. These errors were assumed to be corrected at a penalty cost. However in the reality if these errors could not be fixed by technical and operational means they would have the potential to cause system failures. An underestimation of errors have been discussed due to the lack of high frequency irradiance data however it must be noted that the model may also be overestimating the errors due computation limitations. One example is the appearance of under generation ramp errors although they system had sufficient up-ramp capability. The cause of this type of event most likely occurred when the optimization model found it cheaper to incur the penalty than to start-up a new generator for just a few MWhrs. Another example is that the demand and generation capacity was reduced by 10% however the actual maximum capacity sizes of the generators remained at a realistic proportions. This reduces the flexibility of the system by making the generators "chunkier" in terms of lowering the number of generators relative to the load they are serving. Additionally it also must be noted that some of these errors, especially over-generation errors, may be caused by the limited 8 hour foresight of the model. More accurate results may be obtained with a longer period of foresight such as a full 24 hour or even 48 hour window to make sure that the large coal generators have enough advance warning to ramp down before shutting down.

In terms of system costs the results indicate operational cost savings up to a point where the penalty costs outweigh the savings. The model assumes a penalty for over-generation but if this energy could be used instead, for example, in a pumped water hydro storage system the costs would turn into a benefit.

Additionally the systems cost comparison only includes the operational costs and therefore does not factor in the cost of the actual installation of the PV systems due to the assumption that the owner of the household bears the capital costs. However, if the utility were to own and operate the system the levelized costs of electricity (LCOE) for PV systems are still significantly more expensive than the advanced combined cycle natural gas-fired alternatives. The 2014 Annual Energy Outlook by the EIA estimates that the LCOE for PV systems and advanced combined cycle generators in the year 2019 to be $118.6/MWhr and $64.4/MWhr [35]. In spite of these additional costs, utilities may have to opt for this option due to the impending policies capping CO_2 and in fulfillment of REPS requirements.

Another concern for utilities are the losses in revenue due to the net-metered configuration of household PV systems. This could be seen in the resulting reduction of coal generation with the penetration of PV. The results show an average of a $94 million dollars loss at the 5.7% penetration level. Utilities argue that although net-metered customers are using less energy, they still rely on the transmission infrastructure which is operated and maintained by the Utility and is included in $/kWhr price of electricity. This could result in an increase in electricity rates for all rate-paying customers. A current debate over the benefits and costs of distributed generation is taking place. The Rocky Mountain Institute has done a review 15 different costs/benefit analysis of distributed generation studies for different regions of the electrical grid [36].

Finally, there is no question that the integration of PV generation reduces system CO_2 emissions. As has been discussed, the EPA plans on placing state specific CO_2 caps on emissions produced by the electricity sector. The proposed caps for North and South Carolina are to be reached by the year 2030 are 1077 lbs/MWhr and 840 lbs/MWhr respectively [30].   Although the CO_2 emissions in scenario B-0% are 936 lbs/MWhr, this is only for the DEC and PEC territory which does not include the entire populations and generation of the two states. The results do show that a reduction of 119lbs/MWhr could be achieved in this region alone by the addition 5.7% in scenario B.

Considering the results and discussion of this analysis, this study suggests that the DEC and PEC region has the technical capability to increase its PV penetrations well beyond its current level of less than 0.5% up to near 5.7% when the base-load nuclear threshold is reached.

5. CONCLUSION

This study examined the limits and economic effects of adding large amounts of distributed PV generation to North and South Carolina electrical system controlled by the DEC and PEC balancing authorities. The analysis was completed using a PV production model to simulate PV production of spatially distributed PV systems in the region based on household density. A unit commitment model was then used to simulate the dispatch and operation of conventional generators. Annual results were examined to identify system limitations, error events, system costs, operational changes, and CO_2 reduction.

The main findings of the study indicate that the most limiting factor the integration in the DEC and PEC balancing authority region is the large generating capacity of base-load nuclear plants. This threshold started to affect PV production at integration levels of 5.7%. System errors appeared in the model at these levels however the validity of these errors in real world context needs further examination due to the lack of high frequency irradiance data and modeling limitations. Operational system costs decreased with PV integration although this is associated with a significant reduction in coal generation and lost revenue for generator owners. Further research is needed to explore the impacts of the capital costs required to achieve the penetration level scenarios found in this study. In all scenarios, CO_2 emissions were reduced with PV integration. This reduction could be used to meet impending EPA state-specific CO_2 emissions targets.

APPENDIX A

Table 6: PV module production performance adjustment values for multiple combinations of module tilt angle and orientation calculated using the NREL PV Watts calculator for the Raleigh, NC.

Performance Orientation Adjustment Values						
		Module Orientation				
		270°(West)	225°	180 °(South)	150°	90°(East)
Module Tilt Angle	0°	0.87	0.87	0.87	0.87	0.87
	15°	0.86	0.93	0.97	0.95	0.86
	30°	0.81	0.94	1.00	0.98	0.81
	45°	0.74	0.91	0.98	0.95	0.75
	60°	0.65	0.83	0.91	0.87	0.66
	75°	0.56	0.72	0.78	0.76	0.57
	90°	0.46	0.58	0.61	0.61	0.47

Table 7: Coal Generator Cluster Summary Statistics

Coal Cluster Summary Statistics						
Cluster		# of Generators in Cluster	Capacity	Year Online	Plant Average Heat Rate	CO2 Emissions Rate
1	Min	4	70.0	1949	5589.8	165.8
	Max		150.0	1987	12097.2	2478.7
	Average		92.3	1960	10470.4	1900.4
	Std. Dev.		33.5	15.6	2817.8	1001.5
2	Min	22	67.5	1941	8892.5	1565.0
	Max		275.0	1987	10922.7	2240.4
	Average		147.8	1960	10391.1	2076.4
	Std. Dev.		65.8	12.0	597.2	201.4
3	Min	19	65.0	1948	9676.0	271.1
	Max		745.2	1980	13152.8	2690.9
	Average		347.9	1962	10119.5	1948.6
	Std. Dev.		249.1	9.4	748.2	426.1
4	Min	3	735.8	1974	9302.9	1909.0
	Max		1080.1	1983	10322.0	2118.1
	Average		965.3	1977	9642.6	1978.7
	Std. Dev.		162.3	4.0	480.4	98.6

Table 8: Natural Gas Combustion Turbine Generator Cluster Summary Statistics

Natural Gas Combustion Turbine Cluster Summary Statistics						
Cluster		# of Generators in Cluster	Capacity	Year Online	Plant Average Heat Rate	CO2 Emissions Rate
1	Min	32	16.3	1968	10451.8	271.1
	Max		158.0	2007	18345.6	2478.7
	Average		53.3	1987	12774.2	1887.9
	Std. Dev.		30.4	17.5	3190.5	536.5
2	Min	24	99.9	1995	37125.0	4651.9
	Max		109.6	2003	123884.1	14848.3
	Average		106.4	1998	66044.7	8050.7
	Std. Dev.		4.6	3.4	40898.6	4806.6
3	Min	20	195.3	1999	7750.9	921.6
	Max		211.8	2009	11411.7	2142.0
	Average		205.4	2001	10509.8	1341.8
	Std. Dev.		7.1	2.0	1204.8	303.6

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