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Mailcode 28221T
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1200 Pennsylvania Avenue, NW.
Washington, DC 20460

Via electronic mail

Comments on the Environmental Protection Agency's Proposed Clean Power Plan

We appreciate the opportunity to submit comments on the Environmental Protection Agency's (EPA) proposed Clean Power Plan (CPP), under Clean Air Act Section 111(d), as a multi-faceted approach to reduce carbon pollution. The Southern Alliance for Clean Energy (SACE) fully supports EPA's intent to reduce our carbon emissions from our nation's power sector as it will protect public health, address carbon pollution that is fueling climate change and move the country towards lower cost, lower risk and cleaner energy sources that will increase jobs and help strengthen our nation's economy. SACE has been a leading voice for energy policy to protect the quality of life and treasured places in the Southeast since 1985. For those of us living in the Southeast, it is even more critical for EPA to create a strong rule that will hold states accountable for their current carbon emissions and push our states to develop more renewable energy generation resources and move past the dirty energy choices of our past, like coal-fired power.

The Southeastern U.S. is overly reliant on high-risk energy choices such as coal, natural gas and nuclear power and has made limited advancement in terms of renewables and energy efficiency in comparison to the rest of the country. Investing in more high risk energy entrenches an antiquated electric distribution technology and will further limit the advancement of cost-effective, reliable, less water-intensive and resilient choices especially renewables such as wind and solar, along with energy efficiency measures, of which this region has yet to fully tap the potential. The EPA should finalize its CPP in a way that incentivizes States to pursue truly clean, affordable energy options versus perpetuating the status quo.

Many areas in the Southeastern U.S., and across the country, are uniquely vulnerable to the threats posed by climate change. The electricity sector's current and future resiliency should be considered while EPA finalizes its CPP, especially in terms of the sector's water intensity. The EPA should prioritize investment in energy options that are less vulnerable to the effects of climate change versus those that have already demonstrated a lack of resiliency.[1] The

[1] Union of Concerned Scientists, "*Power Failure: How Climate Change Puts Our Electricity at Risk -- and What We Can Do*." Available at http://www.ucsusa.org/assets/documents/Power-Failure-How-Climate-Change-

smart, resilient and less water-intensive energy choices we make today will have long-lasting benefits for the country's economic and environmental health.[2]

SACE's comments will focus on the weaknesses we have identified in EPA's draft CPP as they pertain to the Southeast and will suggest changes in various approaches taken by EPA in the proposed rule. Where possible, SACE has supported its criticisms and suggestions for strengthening the CPP with Southeast specific data.

The main sections of our comments are as follows:

1. Support for flexible approaches to carbon reductions
2. Renewable energy resources in the Southeast
3. Energy efficiency resources in the Southeast
4. Nuclear energy and associated compliance risks
5. Conclusion

1. Support for flexible approaches to carbon reductions

SACE supports the EPA's efforts to enact a flexible carbon dioxide emission standard that allows states to comply with emission goals in a manner that maximizes reductions and minimizes economic impacts of the regulation. Specifically, SACE supports the options for states to submit either single or multi-state compliance plans in order to comply with the CPP. The Southeast is home to several large utilities that operate across state lines, such as Duke Energy, Southern Company and the Tennessee Valley Authority (TVA). By allowing states to work together to craft multi-state compliance plans, EPA is acknowledging the cross-state operations of many major utilities. By allowing utilities to engage with the various states in which they operate and share costs and burdens across a region, EPA is illustrating that it is using its best efforts to enact a desperately needed public health regulation while minimizing the impact on the economy. SACE supports the inclusion of the multi-state compliance option in the final CPP. EPA has also allowed states to convert the current rate-based emission goals to mass-based emission goals, in order to create a simplified goal that will allow states to work together more easily to craft multi-state compliance plans if needed.

SACE also supports EPA's approach to determining the Best System of Emission Reductions (BSER) for carbon dioxide emissions under Section 111(d) of the Clean Air Act. In the CPP, EPA has laid out 4 building blocks that reduce carbon emissions from fossil fueled power plants. Although SACE takes issue with assumptions made within EPA's building blocks (discussed in more detail below), SACE supports EPA's broad approach to reducing carbon emissions from our nation's electric power sector as laid out in the 4 building block approach.

Additionally, SACE acknowledges EPA's authority to implement a federal compliance plan for states that either do not submit a 111(d) state compliance plan or fail to submit a compliance plan that will achieve that state's designated emission rate goal. EPA, however, should include framework or guidance on what a federal compliance plan and enforcement would work when it releases the final CPP.

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[2] See the Union of Concerned Scientists' *Energy and Water in a Warming World Initiative* and corresponding reports at http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/about-energy-and-water-in-a-warming-world-ew3.html.

EPA released a Notice of Data Availability (NODA) on October 27, 2014 in which EPA requested comments on the issue of whether some or all of the energy efficiency credits and renewable energy generation that states add to the denominator in their CO_2 emissions rate calculation would reduce fossil generation from existing power plants, and whether and how this should be incorporated into the numeric calculation of state targets. We believe it is reasonable for the EPA to assume that a portion of the generation provided by incremental energy efficiency and renewable generation will be used in the future to displace new fossil generation (either from new or existing power plants) that would otherwise be necessary to serve population and economic growth (i.e., growth in the demand for energy services), and a portion will be used to displace historical generation from existing power plants.

We suggest a methodology where it is first assumed that incremental energy efficiency and renewable generation offsets new fossil generation, with any remainder displacing historical generation from existing power plants. And regarding the latter, SACE supports the option presented in Section C(a) of the NODA where remaining energy efficiency and renewable generation replaces historical fossil generation on a pro rata basis. This is most consistent with what is likely to take place in the real world in our view where decisions about displaced generation are made for both economic and environmental reasons.[3]

2. Renewable Energy Resources in the Southeast

In its draft CPP, EPA put forward a Proposed Approach and Alternative Approach for the role of renewable energy (RE) in its carbon emission reduction plan. Unfortunately, the methodologies and associated assumptions EPA used in developing these two approaches severely underestimates the potential RE can and should play in reducing U.S. carbon emissions from the power sector. EPA's proposals would result in target renewable energy levels below Energy Information Administration (EIA) business-as-usual projections for 2020, and only slightly above EIA projections for 2030.[4]

The following section highlights key weaknesses in both of EPA's approaches, in addition recommending an entirely different methodology that SACE can validate as technologically, and economically sound in the southeastern U.S. This section is separated into five primary sub-sections, including:

a) The methodologies used by EPA for the Proposed and Alternative Approaches are overly conservative;
b) EPA underestimates the potential of wind energy in the Southeast;
c) EPA underestimates the potential of solar energy in the Southeast;
d) EPA fails to recognize biomass as a viable RE option;
e) EPA should set the renewable energy target using the Union of Concerned Scientists' (UCS) "Demonstrated Growth Approach;"[5] and
f) The Southeast's ability to meet (or exceed) the UCS Approach.

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[3] See also Southwest Energy Efficiency Project (SWEEP)'s comments on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34924 (June 2, 2014).

[4] Union of Concerned Scientists. October 2014. *Strengthening the EPA's Clean Power Plan*. Available at http://www.ucsusa.org/sites/default/files/attach/2014/10/Strengthening-the-EPA-Clean-Power-Plan.pdf

[5] *Id.*

a) The methodologies used by EPA for the Proposed and Alternative Approaches are overly conservative.

Under EPA's Proposed Approach, the Southeast region's RE target (10% of 2012 generation levels by 2030) is based on North Carolina's Renewable Portfolio Standard (RPS) target, which is one of the weakest (lowest) in the United States.[6] Its relatively weak goals should not be viewed as a useful perspective on the potential for regional development of renewable energy. For example, North Carolina utilities have already gone beyond the state goals for on-system solar energy development. Relying on the North Carolina standard limits the Southeast to arbitrarily conservative RE generation targets and fails to recognize utility and regulator engagement in other strategies (i.e. not mandates) to accelerate market trends in Southeastern states.

Further, the Proposed Approach relies on "regional growth factors" for determining target RE generation levels for each state. There is no floor to each state's RE generation level, which in part causes several states to have 2030 RE targets below the regional target level. For example, despite the southeast having a 10% regional target for RE, Alabama (9.3%), Kentucky (1.9%), and Tennessee (5.5%) all have state-level targets below the regional level.

The RE target generation level is a misnomer, because it *is a cap*, and therefore once achieved the RE generation level is assumed to remain flat through 2030. Applying such a cap is an arbitrary step that fails to capitalize on the momentum of a particular industry, and particularly ironic given that North Carolina has already exceeded the solar portion of its standard that serves as the basis for this cap. If this cap is used, based on EPA calculations, Georgia and Mississippi reach the 10% renewable energy generation level by 2027, North Carolina and South Carolina do so by 2028, and Virginia does so by 2026. After meeting the 10% renewable energy generation target, EPA's target calculation assumes that none of these states increase renewable energy generation any further.

EPA's Alternative Approach also uses an overly conservative methodology for determining state RE target levels. The Alternative Approach chooses the lower of two values produced for each RE technology, via a "benchmark development rate" versus an EPA Integrated Planning Model (IPM) run. Due to incorrect cost and performance assumptions, the IPM model generally produces low output target levels for wind and solar. Similarly, the benchmark development rate also generally results in low capacity target levels. For example, EPA derives a development rate of 0.009% for solar, despite national solar capacity increasing by nearly 300% between mid-2012 and mid-2014. As illustrated in Table 1, selection of the "least stringent" of two methods which are both out of step with current data results in renewable energy targets of 02% across the Southeast, a number that can easily be exceeded in just a few years.[7]

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[6] Lawrence Berkeley National Laboratory. (September 22, 2014) Renewable Portfolio Standards in the United States: A Status Update. Available at http://emp.lbl.gov/sites/all/files/2014%20RPS%20Summit_Barbose.pdf

[7] Percentages based on 2030 RE target (excluding hydro) generation levels as a fraction of 2012 total generation.

Table 1. EPA Alternative Approach, 2030 Target Generation Percentages (percentage excludes hydro and is based on 2012 generation levels)

State	**2030 Generation**
Alabama	0.2%
Florida	0.9%
Georgia	0.9%
Kentucky	0.2%
Mississippi	0.5%
North Carolina	1.7%
South Carolina	1.0%
Tennessee	0.2%

Source: EPA 2014[8]

EPA's Proposed and Alternative Approaches use 2012 as the base year for setting renewable penetration levels for when the rule goes into effect – 2017. The combination of continued performance improvements and price declines, coupled with an expiring federal Production Tax Credit (PTC), and an approaching roll-back sunset date for the federal Investment Tax Credit (ITC) have fueled major capacity additions, making reference to 2012 levels obsolete.[9] Not accounting for current and projected market expansion between 2012 and 2017 distorts the methods proposed by EPA, and ultimately undermines the true potential of solar and other renewable technologies.

For example, EIA projects that wind power capacity will increase by 8.8% in 2014, and 16.2% in 2015.[10] Solar capacity at a national level increased by nearly three times between mid-2012 and mid-2014.[11] See Figure 1. The southeast has contributed to these gains, doubling its solar capacity between 2012 and 2013.[12]

[8] Environmental Protection Agency (June 2014). Alternative RE Approach Technical Support Document. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-alternative-re-approach.pdf

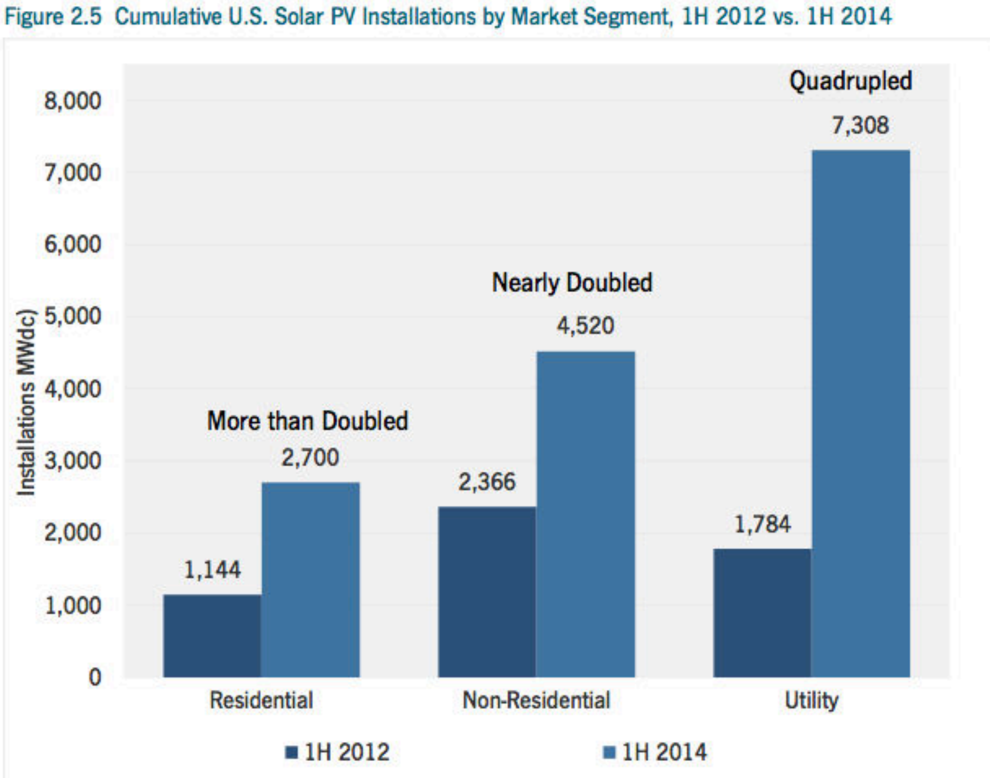
[9] The Federal Production Tax Credit expires at the end of 2014, and the Federal Investment Tax Credit expires for the residential sector and will be rolled back from 30% to 10% for the corporate sector, at the end of 2016.

[10] Energy Information Administration (EIA), Short-Term Energy Outlook. October 7, 2014. Available at http://www.eia.gov/forecasts/steo/report/renew_co2.cfm

[11] Greentech Media (GTM) and Solar Energy Industries Association (SEIA), (2014). U.S. Solar Market Insight Report. Q2 2014, Executive Summary. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

[12] Interstate Renewable Energy Council (IREC), (July 2014) U.S. Solar Market Trends 2013.

Figure 1. Cumulative U.S. Solar PV Installations by Market Segment, 1H 2012 vs. 1H 2014



As is also depicted in this figure, distributed generation (Residential and Non-Residential) capacity is a major component of solar development, accounting for about 40% of all solar photovoltaic (PV) capacity installed (over 1,600 MW-ac) in 2013 and nearly half the cumulative solar PV capacity installed to date in the U.S.[13],[14] Both the benchmark rate approach and IPM model approach fail to capture existing and potential distributed generation, which is a major omission from the solar technology sector. In addition to being a power source that does not have emissions, distributed generation has other unique "value" benefits for customers and the grid that should not be overlooked.[15]

b) EPA underestimates the potential of wind energy in the Southeast.

EPA significantly underestimates wind energy potential and the possible contribution of wind energy in reducing greenhouse gas emissions across the Southeast region. This is most clearly represented in assumptions used behind EPA's Alternative Approach.

In creating a "development rate", EPA's estimated wind energy potential relies on data from 2010 that does not represent the current state of the wind industry, nor will it represent the technological advancements available between now and 2030. Taller wind turbines reach better wind speeds making wind power more economical and expand resource assessment

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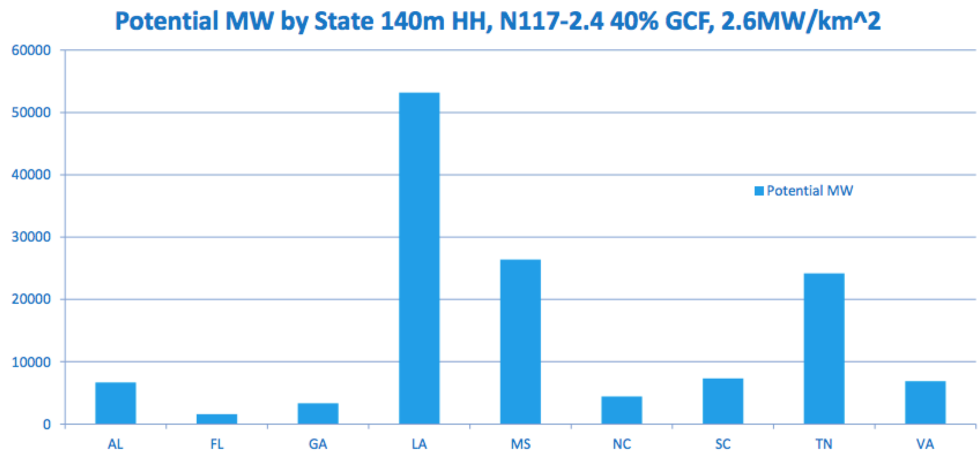
[13] Solar Energy Industries Association (SEIA) and Greentech Media Research (GTM). U.S. Solar Market Insight Report: 2013 Year-in-Review.
[14] DC to AC conversion rates were calculated using a .85 de-rate factor and a 20% AC capacity factor.
[15] Rocky Mountain Institute. (2013). "A Review of Solar PV Benefit & Cost Studies: Second Edition. Available at http://www.rmi.org/elab_emPower

estimates. Specifically, the plan's wind energy estimates relied on hub heights of 80 meters[16]; however, the average wind turbine hub height installed in 2012 was 100 meters. Several turbine manufacturers are developing towers up to 140-meter hub heights, which would dramatically expand the onshore wind energy potential, as illustrated in Figured 2.

Figure 2. Onshore Wind Energy Potential, by State, >40% Capacity Factor (Megawatts)[17]



The impact of the taller wind turbines is transformative. For example, Tennessee's estimated wind energy resources are approximately eighty-three times greater (over 25,000 megawatts of potential) when conducting a resource assessment using a 140-meter tower, as opposed to an 80-meter tower (approximately 300 megawatts of potential).[18] EPA must not rely on a technical potential study that is restricted to 80-meter towers because – as just one example demonstrates – it would result in excluding over 98% of Tennessee's estimated wind energy resources.

To put this in perspective, approximately one-twentieth of Tennessee's updated wind energy resource could provide more power than estimated by the EPA plan for the entire southeast region. As seen in Figure 2, this potential is even greater in Louisiana and Mississippi. Onshore wind energy potential for the south has greatly expanded. Over 134,000 megawatts of onshore wind potential now exists with capacity factors over 40%.[19]

Southeastern states also have additional out-of-state wind energy resources available. Newly proposed high voltage direct current transmission projects could substantially increase the amount of low-cost wind energy resources available to southern states. Two large-scale HVDC projects have been proposed to connect the Plains' strong wind resource to the South's strong energy demand. The Plains & Eastern Clean Line is an HVDC project designed to connect up to 3.5 gigawatts (GW) of wind energy from the plains to Tennessee

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[16] National Renewable Energy Laboratory (NREL) (February 4, 2010). Estimates of Windy Land Area and Wind Energy Potential, by State, for areas >=30% Capacity Factor at 80m. Available at http://apps2.eere.energy.gov/wind/windexchange/docs/wind_potential.xlsx

[17] NREL. (2013). Land-Based Wind Potential Changes in the Southeastern United States." Available at http://www.nrel.gov/docs/fy14osti/60381.pdf

[18] National Renewable Energy Laboratory (February 4, 2010). Estimates of Windy Land Are and Wind Energy Potential, by State, for areas >=30% Capacity Factor at 80m. Available at http://apps2.eere.energy.gov/wind/windexchange/docs/wind_potential.xlsx

[19] *Id.*

and the South beyond.[20] The Southern Cross is an HVDC project designed to connect up to 3 GW of wind energy from Texas to northern Mississippi, and into other parts of the Southeast.[21] Due to the higher wind speeds, the cost of wind energy resources from these HVDC projects will be extremely cost competitive.

Further, several utilities throughout the Southeast have already purchased wind energy via existing transmission lines. These purchases are significant because most states in the south do not require utilities to purchase renewable energy via renewable portfolio standards. Some utilities have made the wind energy purchases because costs are less than utility avoided costs. Wind power purchase agreements are typically secured for twenty years. Below is a list of utility companies in the south purchasing wind energy.

Table 2. Southern Utilities Purchasing Wind Energy

Utility	Year Delivered	Capacity
Alabama Power	2012	404 MW
Georgia Power	2016	250 MW
Tennessee Valley Authority	2010-2012	1,542 MW
Southwestern Electric Power Company	2011-2013	469 MW

Sources: Alabama Power[22], Georgia Power[23], Tennessee Valley Authority[24], Southwestern Electric Power Company[25]

Based on the IPM model results under EPA's Alternative Approach, approximately 5,671 gigawatt hours of electricity from wind power in the year 2030 are attributed to Arkansas, Georgia, Kentucky, North Carolina, South Carolina, Tennessee and Virginia. However, the wind energy already being or planned to be purchased by southern utilities from out-of-state projects results in about 8,000 GWh of wind energy.[26]

Costs associated with onshore wind deployment are also greatly overestimated by EPA. For the EPA estimates, cost assumptions for onshore wind generation begin at $2,258 per kW in the year 2016, and decline to $1,864 per kW by the year 2050.[27] These figures are substantially higher than actually reported wind energy capital costs. A new Lawrence

[20] Clean Line Energy (2014). Plains & Eastern Clean Line. More information available at http://www.plainsandeasterncleanline.com/site/home

[21] Pattern Energy (2013). Southern Cross. More information available at http://www.southerncrosstransmission.com/overview.html

[22] Alabama Power (2014). Winds of Change. More information available at http://www.alabamapower.com/environment/news/chisholm-view-project-provides-low-cost-power.asp

[23] Williams, Dave (2014, May 20). Regulators OK Georgia Power wind energy purchase, Atlanta Business Chronicle. Available at http://www.bizjournals.com/atlanta/blog/capitol_vision/2014/05/regulators-ok-georgia-power-wind-energypurchase.html

[24] Tennessee Valley Authority (October 2013). Energy Purchases from Wind. More information available at http://www.tva.com/power/wind_purchases.htm

[25] Southwestern Electric Power Company (January 25, 2012). AEP SWEPCO Signs Wind Power Purchase Agreements for 359 Megawatts. More information available at https://www.swepco.com/info/news/ViewRelease.aspx?releaseID=1183

[26] Based on a 35% capacity factor.

[27] Environmental Protection Agency (2014). Chapter 4. More information available at http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v513/Chapter_4.pdf

Berkeley National Laboratory ("LBNL") report documents recent low wind-power prices and overall cost reduction trends for the wind industry.[28]

In 2013, average power purchase agreement ("PPA") prices reached $25 per MWh. Since many of the installed projects last year were able to qualify for the federal Production Tax Credit ("PTC"), or a similar incentive, the reported PPAs may reflect a reduction of approximately $15 per MWh when taking into consideration the PTC. Average PPA prices fell approximately 64% between 2009 ($70 per MWh) and 2013 ($25 per MWh). Overall, wind energy prices are declining due to lower wind turbine prices and higher wind turbine performance (in terms of capacity factor output). Recent turbine prices have been in the $900-$1,300 range per kW of generation capacity, with total installed average costs of approximately $1,630 per kW in 2013. Operations and maintenance costs associated with newly constructed wind farms dropped from $23 per MWh (or $55 per kW of installed capacity) in the 1990s to about $9 per MWh (or $23 per kW of installed capacity) for projects developed since 2010.

Wind turbine technology has advanced significantly since modern turbines were first designed in the 1980s. Multi-megawatt machines, taller turbine hub heights and longer blades have greatly contributed to increased power generation and lower costs.[29] Wind farm projects have now been proposed in every state in the South. The particular type of turbines likely to be deployed in the South are "Class III" turbines, based on International Electrotechnical Commission (IEC) Standard 61400. Class III turbines are designed to operate in lower wind speed areas and could achieve capacity factors of 40-50% in areas across the South. Some examples of Class III wind turbines are listed below.

Table 3. IEC Class III Wind Turbines

Turbine Model	Megawatt Capacity	Hub Heights	Rotor Diameter
GE 2.5-120	2.5 MW	Up to 139 meters	120 meters
Nordex N117	2.4 MW	Up to 140 meters	117 meters
Siemens 2.3-113	2.3 MW	Up to 142.5 meters	113 meters
Vestas V126-3.3	3.3 MW	Up to 137 meters	126 meters

Sources: General Electric[30], Nordex[31], Siemens[32], Vestas[33]

c) EPA underestimates the potential of solar energy in the Southeast.

A review of the inputs and assumptions used for EPA's IPM model, demonstrates a poor

[28] Wiser, Ryan; Bolinger, Mark (August 20, 2014). 2013 Wind Technologies Market Report, LBNL. Available at http://energy.gov/sites/prod/files/2014/08/f18/2013 Wind Technologies Market Report_1.pdf
[29] Wiser, Ryan; Bolinger, Mark (August 2013). 2012 Wind Technologies Market Report, LBNL. Available at http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf
[30] General Electric (2013). Introducing GE's 2.5-120. Available at http://www.ge-energy.com/content/multimedia/_files/downloads/GEA30534_Wind_2.5-120_Brochure_LR.PDF
[31] Nordex (2013). Nordex N117. Available at http://www.nordex-online.com/en/produkte-service/wind-turbines/n117-24-mw.html
[32] Siemens (2011). SWT-2.3-108. Available at http://www.energy.siemens.com/hq/pool/hq/power-generation/renewables/wind-power/wind%20turbines/Siemens%20Wind%20Turbine%20SWT-2.3-108_EN.pdf
[33] Vestas (2014). V126-3.3 MW IEC IIIA. Available at http://nozebra.ipapercms.dk/Vestas/Communication/Productbrochure/3MWbrochure/3MWProductBrochure/

understanding of the current solar PV market. EPA's IPM model used an installed cost of $3,364 per kW-alternative current (ac) for utility-scale PV starting in 2016, dropping to $2,859 per kW-ac in 2030 and $2,533 per kW-ac in 2050. These "forecasted prices" – even as far out as 2050 – are extremely high and inconsistent with today's prices and trends. For example, utility-scale PV projects installed during the second quarter of 2014 averaged a price of $2,130 per kW-ac. Notably, this price has dropped by 52% since the second quarter of 2011.[34,35,36] Similar price drops have occurred in the commercial (54%) and residential (42%) sectors.

Analysts anticipate the downward cost trend to continue based on further economies of scale and innovation through areas such as better solar cell performance.[37] A recent Public Service Company of New Mexico ("PNM") filing for regulatory approval of 40 MW-ac of utility-scale PV, to be built in 2015 as two separate 20 MW-ac projects, was estimated to cost $1,980 per kW-ac.[38]

The recent and projected price points for power purchase agreements (PPAs) provide additional evidence of the economic competitiveness of PV technology.[39] In the first half of 2014, PPA pricing across the country for new utility PV installations ranged between $50-$70/MWh.[40] As demonstrated in the below figure, levelized PPA prices have been dropping steadily by about $25/MWh per year since 2007. The Southeast is a part of this trend. For example, Georgia Power recently revealed that they selected utility-scale solar bid prices at levelized prices below $65/MWh.[41]

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[34] Feldman, D.; Barbose, G.; Margolis, R.; Darghouth, N.; James, T.; Weaver, S.; Goodrich, A.; Wiser, R. (2013) "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. 2013 Edition." NREL & LBNL. Available at http://emp.lbl.gov/publications/photovoltaic-system-pricing-trends-historical-recent-and-near-term-projections-2013-edi

[35] GTM and SEIA. (2014). U.S. Solar Market Insight Report. Q2 2014, Executive Summary. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

[36] DC to AC conversion rates were calculated using a .85 de-rate factor and a 20% AC capacity factor

[37] UBS. "Will Solar, Batteries, and Electric Cars Re-Shape the Electricity System?" Q-Series. Global Utilities, Autos & Chemicals. August 20, 2014.

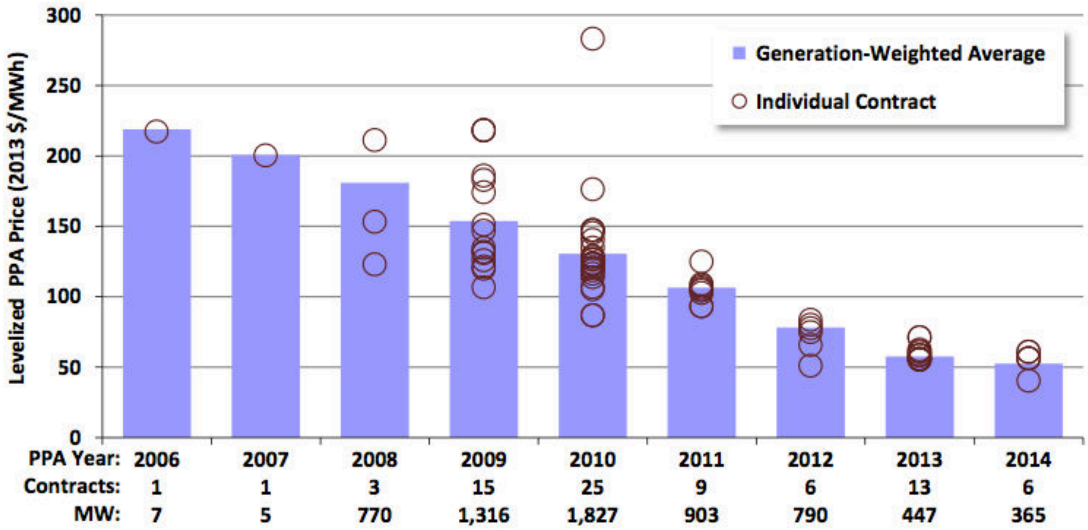
[38] Lawrence Berkeley National Laboratory (LBNL). Utility-Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States. September 2014.

[39] Over the past 6 years levelized PPA prices for utility-scale solar projects have fallen by an average of $25/MWh per year. Bolinger, M. and S. Weaver. (2013) "Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States. LBNL. Available at http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends

[40] GTM. (2014). *Five Things You Should Know About the U.S. Utility-scale PV Market*. Available at http://www.greentechmedia.com/articles/read/Five-Things-You-Should-Know-About-the-US-Utility-Scale-PV-Market

[41] Georgia Power Company, "Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements" (October 10, 2014), Georgia Public Service Commission Docket No. 38877.

Figure 3. Levelized Power Purchase Agreements for PV Installations, by Contract Vintage[42]



The U.S. Department of Energy (DOE) has demonstrated that using more realistic installed cost figures results in very significant levels of solar capacity being added throughout the United States. The DOE SunShot Initiative has a current goal to reduce solar costs to grid parity levels by 2020.[43] The actual values targeted for PV are $1,000 per kW-direct current (dc) for utility-scale, $1,250 for commercial, and $1,500 for residential installations. Converted[44] to AC values, these targets come out to: $1,177 per kW-ac for utility-scale, $1,470 for commercial, and $1,765 for residential. The National Renewable Energy Laboratory (NREL) recently reported that DOE's targets are close to the range of the most recent analyst projections.[45]

In the SunShot Vision Study[46], DOE used sophisticated modeling[47] to determine the penetration levels of solar if those installed costs targets ($1,000 per kW-dc, etc.) were achieved by 2020. As demonstrated by the modeling, the DOE SunShot 2030 capacity levels would result in enough solar to meet over 13% of the annual net electricity generation for the Southeast region (based on 2012 generation levels). The states vary considerably in capacity levels, ranging from about 2% of (2012) generation in Alabama to over 26% in Florida. The following table highlights capacity and generation levels based on the 2030 results of the SunShot Vision Study, along with approximate percentage levels based on 2012 total generation (to be comparable with EPA's approaches).

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[42] LBNL. (September 2014) Utility-Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.
[43] U.S. Department of Energy. (2012) "SunShot Vision Study." Available at http://energy.gov/eere/sunshot/sunshot-vision-study
[44] DC to AC conversion rates were calculated using a 0.85 de-rate factor.
[45] NREL. (2014) "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. 2014 Edition." Available at http://www.nrel.gov/docs/fy14osti/62558.pdf
[46] U.S. DOE. (2012) "SunShot Vision Study." Available at http://energy.gov/eere/sunshot/sunshot-vision-study
[47] DOE used a combination of NRELsunshot-vision-studyvision-study" -TerReEDS), SolarDS, and a third-party provided model – GridView, to determine the capacity increases and economic impacts of achieving the DOE SunShot price targets, in addition to confirming the basic hourly operational feasibility of the scenarios considered.

Table 4. SunShot Vision Study 2030 Capacity and Generation Results, as a percentage of 2012 generation levels[48]

State	MW-ac	MWh	% of 2012 Generation
Alabama	1,955	3,425,160	2.2%
Florida	33,235	58,227,720	26.3%
Georgia	11,135	19,508,520	16.0%
Kentucky	2,125	3,723,000	4.1%
Mississippi	1,020	1,787,040	3.3%
N. Carolina	6,970	12,211,440	10.5%
S. Carolina	12,325	21,593,400	22.3%
Tennessee	3,315	5,807,880	7.5%
Total	72,080	126,284,160	13.6%

As with the price targets, the capacity potential resulting from DOE's model is not unrealistic. The same NREL report used in creating a benchmark development rate under EPA's Alternative RE Approach, found that the Southeast's urban and utility-scale PV technical potential is over 17,000 GW,[49] and could generate over 3000% of the 2012-generation needs for the entire region. Separately, the technical potential of rooftop solar for the southeast region is over 150 GW, which could generate over 20% of the region's 2012-generation level.

SACE has conducted several analyses to determine solar PV net dependable capacity factors for Southeastern utilities. The dependable capacity factor is a key indicator for utilities regarding the value of potential generating sources. Our research, which leverages dozens of solar load profiles throughout the Southeast, demonstrates that tracking and fixed solar systems have dependable capacity factors of at least 60% and 50%, as detailed in Attachment A.[50] These are significant levels that show that solar is particularly valuable because it can be used to meet generation needs when demand is highest.

d) Fails to recognize biomass as a viable renewable energy option.

EPA's RE building block analysis underappreciates the potential of diverse bioenergy resources to reduce carbon emissions and mitigate climate. Dispatchable biopower is valuable for utility operations and complements variable resources such as wind and solar. SACE focuses on those forms of biomass and beneficial use of methane that are widely agreed to be climate friendly. Notwithstanding the absence of a Biogenic Carbon Accounting Framework, there are diverse forms of bioenergy technologies and biomass resources that are widely accepted as beneficial to climate mitigation and greenhouse gas reductions. Scientific

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[48] DC to AC conversion rates were calculated using a 0.85 de-rate factor and a 20% AC capacity factor.
[49] NREL. (2012). U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. Available at http://www.nrel.gov/docs/fy12osti/51946.pdf
[50] This research was conducted with load profiles created by Clean Power Research, and includes an analysis of Duke Energy Carolinas, Southern Company, and the Tennessee Valley Authority.

consensus on these forms of bioenergy is so broad that they might be called "no regrets" bioenergy.

Most notably, the proposed rules largely overlook the economic and technical potential for climate mitigation through beneficial use of methane from landfill gas (LFG), livestock manure, and waste-water treatment plants (WWTP) via anaerobic digestion (AD). This is especially concerning in light of the IPCC's recent upward revision of the Global Warming Potential (GWP) of methane, from a 2007 estimated GWP_{100} of 25 to a 2013 estimated GWP_{100} of 34 times that of CO2.[51] We would encourage EPA to adopt (either in tandem with the final rule or soon after) guidance for incorporating methane reductions into 111(d) state compliance plans).

The economic and technical potential for climate mitigation through beneficial use of methane is substantial. Energy uses of methane from LFG, livestock manure, and WWTP would directly deliver significant greenhouse gas reductions, and would also offset the need for electricity generation from high carbon sources such as coal and natural gas. There are hundreds of landfills[52] [53], WWTPs[54], and livestock farms throughout the southeast that are potential candidates for bioenergy development.

Also worthy of mention is biomass-fueled combined heat and power (CHP), which has been found – even by studies critical of bioenergy – to shorten the timeframe before climate benefits are realized.[55,56]

We are unable to disclose pricing data we have obtained as evidence during regulatory processes in our focus states. However, published price data are featured here as Levelized Cost of Energy (LCOE), from five different types of biopower.

Table 5. Levelized Cost of Energy (LCOE) from Biomass (US Dollars per kWh)[57]

Cofiring Low	Cofiring High	Stand-alone Biopower Low	Stand-alone Biopower High	Biomass CHP Low	Biomass CHP High	Anaerobic Digester Low	Anaerobic Digester High	LFG Low	LFG High
0.04	0.13	0.06	0.29	0.07	0.29	0.06	0.15	0.09	0.12

Because biomass resources come from carbon recently captured in the landscape by growing plants, the use of certain fast growing biomass resources, or biomass that would otherwise rapidly decompose, or otherwise be burned without energy recovery, is beneficial in the near

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[51] IPCC 2013. More information available at http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_All.pdf

[52] DOE EERE 2004. More information available at http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_Aldenergy/pdfs/chp_opportunityfuels.pdf

[53] EPA EERE 2004. More information available at http://www.climatechange2013.org/images/uploads/WGIAR%5Bhttp://www.epa.gov/lmop/documents/xls/candlfslmopdata.xls

[54] DOE EERE 2004, "CHP Opportunity Fuels." More information available at http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_opportunityfuels.pdf

[55] Manomet Center for Conservation Sciences, 2010. More information available at http://www.mass.gov/eea/docs/doer/renewables/biomass/manomet-biomass-report-full-hirez.pdf

[56] Biomass Energy Resource Center, 2012. Biomass Supply and Carbon Accounting for Southeastern Forests. Available at http://www.nwf.org/pdf/Global-Warming/NWF-SE-Carbon-Study.pdf

[57] IRENA 2012, Renewable Energy Technologies Cost Analysis Biomass, accessed June 30, 2014. Available at http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-BIOMASS.pdf

term. In contrast, the use of roundwood logs, pulpwood, or larger diameter trees is shown in scientific literature as being unhelpful for short-term purposes of climate change mitigation. These long-lived forest resources take too long to re-grow and re-capture biogenic carbon and EPA should not incentivize their use in biopower applications.

e) EPA Should Set the Renewable Energy Target Using the Union of Concerned Scientists' Demonstrated Growth Approach.

SACE has reviewed the Union of Concerned Scientists' (UCS) "Demonstrated Growth Approach," and recommends for determining the BSER in the EPA's renewable energy building block.[58] The UCS approach: 1) addresses inadequacies of EPA's Proposed and Alternative approaches as discussed previously; 2) better reflects the current and projected market development trends for renewable energy (nationally and in the southeast); and, 3) is technically and economically feasible for southeastern utilities.

As with SACE and other groups that are closely familiar with the renewable energy industry, UCS viewed the EPA Proposed and Alternative RE approaches as an underestimation of the actual potential RE can and should play in reducing U.S. carbon emissions from the electric power sector. As a result, UCS developed and proposed a more realistic method which relies on several core components, including:

- Setting a national renewable energy growth rate benchmark based on demonstrated growth in the states from 2009 to 2013;
- Assuming full compliance with current state renewable electricity standard (RES) policies, as set by law, that require certain percentages of electricity to come from renewable sources; and
- Accounting for actual and expected renewable energy growth between 2013 and 2017.

More specifically, UCS found that the national average annual increase for state renewable energy growth from 2007-2013 was about 1% of electricity sales per year, and therefore set that rate as the minimum growth rate that would be required starting in 2020. States below the 1% historic growth rate would have from 2017-2020 to achieve the rate, and states above the 1% would have to maintain their growth rates from 2017-2030, up to 1.5%. Further, states would have to meet the greater of two goals – the UCS growth rate or their individual RES target (if they have one), with an overall cap of 40% of any single state's electricity sales.

Another key difference in the UCS Approach compared to EPA's Approaches is that UCS used actual 2013 data (including distributed generation) plus projected generation from utility-scale solar and wind projects under construction through 2016, to determine each state's 2017 baseline generation levels.

f) Southeast's ability to meet (or exceed) the UCS Approach.

The U.S. has experienced a boom in renewable (particularly solar and wind) energy development over the past several years. This has been driven in part by policies, and largely by technology advancements and declining costs. A critical component to the UCS approach

[58] Union of Concerned Scientists. October 2014. *Strengthening the EPA's Clean Power Plan*. Available at http://www.ucsusa.org/sites/default/files/attach/2014/10/Strengthening-the-EPA-Clean-Power-Plan.pdf

is in being more consistent with actual market trends. Where the EPA uses 2012 RE generation as a baseline for 2017, UCS uses actual 2013 data (which includes distributed generation), and expected RE generation for wind and solar projects under construction through 2016. Further, RE growth rates are state-specific (within the 1-1.5% range or based on existing RPS compliance rules), and are therefore not limited to any one state or region's RPS rules. This is particularly true for the Southeast, where there is only one state with an RPS, yet several other states are pursuing renewable energy independent of RPS mandates.

In the Southeast, the UCS Approach results in 14% of electricity sales being met with renewable energy by 2030, as opposed to 7% under EPA's Proposed Approach. As demonstrated in the previous section, the Southeast has more than enough technical potential from renewable resources to meet this level of penetration, and current market growth is already occurring.

Solar energy development is booming across several Southeastern states and this is anticipated to increase with continued price declines and the approaching roll back of the federal ITC at the end of 2016. Here are some examples of minimum expected solar development in southeastern states – note that North Carolina is the only state listed here with an RPS:

- North Carolina, the only of these states with a mandatory RPS, is already anticipated to install 300 MW-ac in 2014[59], and Duke Energy alone is already planning to add nearly as much in 2015.[60] North Carolina will have close to, if not exceeding, 1000 MW-ac of solar installed by the end of 2015.[61]
- Georgia will go from less than 20 MW-ac of installed PV capacity in 2012 to nearly 900 MW-ac by the end of 2016.[62]
- The Tennessee Valley Authority (TVA) has over 260 MW-ac of solar installed or under contract,[63] and assuming that solar programs remain at 2014 levels, TVA will have nearly 500 MW-ac total by the end of 2016.
- South Carolina recently passed the Distributed Energy Resource Program Act, which is expected to bring at least 300 MW-ac of additional solar online in the state by 2021.[64]

Furthermore, SACE is aware of substantial commercial solar development activities in Mississippi, Alabama, and Florida. The opportunity for solar energy in the Southeast is so

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[59] GTM and SEIA, (2014). U.S. Solar Market Insight Report, Q2 2014, Executive Summary. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q2
[60] Duke Energy. (September 15, 2014) "Duke Energy Commits $500 million to North Carolina Solar Power Development." Available at http://www.duke-energy.com/news/releases/2014091501.asp
[61] Interstate Renewable Energy Council (IREC), (July 2014) U.S. Solar Market Trends 2013.
[62] See Georgia PSC Docket No. 37854, Attachment STF-2-1 (Georgia Power states that it will have 797 MW-dc of solar capacity once its Advanced Solar Initiative Prime program is completed in late 2016); see also Bloomberg, Georgia Power to Build 90 MW-dc of Army Solar Plants (May 15, 2014), available at http://www.bloomberg.com/news/2014-05-15/georgia-power-to-build-90-megawatts-of-army-solar-plants.html (Georgia Power announced plans to build an additional 90 MW of solar at 3 army bases in Georgia, to be placed in service by the end of 2016).
[63] See TVA's Generation Partners Website available at http://www.tva.com/greenpowerswitch/providers/ See also TVA's "Fact Sheet: Renewable Energy" from September 2014 available at http://www.tva.com/news/releases/julsep14/renewable_energy_fact_sheet.pdf
[64] CleanTechnica. South Carolina Solar is Rising. August 4, 2014. Available at http://cleantechnica.com/2014/08/04/south-carolina-solar-rising/ The Act can be found at: http://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm

great, as demonstrated by the DOE SunShot Vision Study, that if solar prices achieve analyst projections by 2020, nearly all of the UCS's 2030 RE generation level for the Southeast could be met with solar.

Wind technology is already capable of meeting significant levels of the Southeastern electricity generation, due to currently available "Class III" turbines, and in fact developers have been prospecting these states over the past couple years. As noted previously, southern utilities are already purchasing over 2,500 MW of wind capacity from out-of-state projects, and transmission lines are in the process of being developed to transmit several gigawatts of wind to several southeastern territories.

Biomass also represents a unique opportunity to leverage low-emitting and dispatchable power production resources in the Southeast.

i) Southeastern Utilities Can Use Renewable Energy to Meet at Least 15-20% of Demand

With the potential for utilities in the Southeast to deploy renewable energy resources on their systems at a scale of 15% or more over the next decade, some may raise concerns about reliability risks or other operational considerations. Elsewhere in the country, technical experts have concluded that variable renewable energy resources can represent as much as 50 percent of electric systems, provided that utilities make "investment in additional distribution and transmission system infrastructure as well as changes in electric system operations, markets, and planning to achieve reliability."[65]

Across much of the United States, these questions are systematically addressed through the planning processes of regional transmission operators (RTOs), independent system operators (ISOs) and super-regional planning councils. For example, the US DOE SunShot analysis included GridView simulations to verify the basic hourly operational feasibility of high solar scenarios, confirming that electricity demand and operating reserves are completely served in all areas during every hour of the year.[66]

However, in the Southeast, several large vertically-integrated utilities conduct their own resource adequacy, reliability and operational planning with minimal market exposure. Due to historically limited solar and wind development, vertically-integrated utilities in the Southeast have not provided analyses of renewable energy that are as comprehensive or similarly robust as those in RTO or ISO regions. While few of their planning studies have thoroughly examined renewable energy resources, these studies do often raise questions regarding renewable resource adequacy, reliability and flexibility.

A new study by SACE, provided as Attachment A, summarizes the information available from these utilities, and answers several key questions (laid out below) with analysis that could be used in a variety of energy planning activities.

- Renewable energy offers dependable on-peak capacity that is effective at replacing conventional power resources. While the specific values vary by technology, a

[65] Linvill, C., Migden-Ostrander, J. and Hogan, M., *Clean Energy Keeps the Lights On*, Regulatory Assistance Project (June 2014).
[66] Note that this GridView analysis was conducted for higher penetration levels based on 2050 results, as opposed to 2030 results. See Chapter 3 of the U.S. Department of Energy SunShot Vision Study. (2012)

blended portfolio of wind and solar resources is likely to provide dependable capacity of approximately 50 MW per 100 MW of nameplate capacity.

- While the dependable capacity ratings of renewable energy would decline with large scale deployment, that decline will be gradual and predictable, and will remain substantial at generation levels of 10-20% of annual energy demand.
- While renewable energy resources are variable, they perform very well during high demand periods when utility systems need to use most of their generation resources. On average, regional solar and imported wind resources should generate at 50-60% capacity factors during these hours. At current and near-term levels of renewable energy use, long-term modeling analysis indicates no increased reliability risks at the system level – even during hours in which renewable energy production might be low. Even if renewable energy is increased to meet 10-20% of annual energy demand, reliability should be relatively unaffected on balance. At these higher levels of renewable energy use, there would be a balance of increased and decreased risks that utilities would need to study and monitor. Hours with increased reliability risks would occur very infrequently, roughly one hour per year on average. That same level of renewable energy generation would also increase the number of hours in which reliability is ensured by about 80 hours per year.

1. Solar power is unlikely to cause some utility systems to effectively shift from a summer to winter peak. With responsible planning and management, renewable energy will not be a problem during a "polar vortex" type event.

2. Utility operators will not need to increase the ramping of convention generation in the near future. Up to around 10% of energy supply, utility systems may actually be easier to operate, since solar energy in the Southeast is closely aligned with system peaks. While the transition point depends on the utility system and the resources applied, even at 10-20% of annual energy demand, the California "duck curve" problem of high ramp rates for conventional generation is unlikely to appear in the Southeast.

These questions have been answered by matching industry-standard data about potential wind and solar generation to the historical generation data supplied by Duke Energy (in the Carolinas), Southern Company (including Alabama, Florida, Georgia and Mississippi subsidiaries), and the Tennessee Valley Authority (serving portions of seven Southeastern states). The methods applied in these analyses apply industry-standard techniques, enhanced to more carefully examine concerns about renewable energy development in the Southeast.

ii) Demonstrating Compliance with a Renewable Energy Target

As discussed above, there are economically feasible (even advantageous) renewable energy resources available in or delivered to the Southeast. These resources can be deployed and operated in a manner that complements the existing generation, transmission and distribution systems as well as other developments needed for the future.

One challenge, however, relates to the effective emissions monitoring and verification, ensuring proper crediting towards compliance with the CPP. Each of the "buckets" identified by EPA comes with its Evaluation, Measurement and Verification (EM&V) and crediting challenges. In the case of renewable energy, the geographic location of the resources may not be well matched to the states with compliance needs, particularly when variable renewable energy resources from different regions are more effective in combination than as stand-alone resources.

We join with many commenters in supporting a system of renewable energy credits as the primary accounting system for EM&V. However, we would point out several issues that EPA must address in its rule in order to avoid double-counting of credits.

One issue is that each state's Renewable Energy Certificate (REC) system comes with its own idiosyncrasies. For North Carolina, compliance is possible using in-state RECs, on-system (but out-of-state) RECs, or off-system (and therefore out-of-state RECs).

Another issue we would point out is that there should be some reasonable correspondence between the RECs generated and the power delivered. Typically PPAs are signed that include delivery of the renewable energy attributes, but in practice the actual power delivery pathway may not be so straightforward. It would be impossibly burdensome to require utilities to identify the source of each and every kilowatt-hour of electricity delivered to their customers, and classify it correctly for purposes of EM&V.

Yet it would also be equally absurd for a state like Florida to demonstrate "compliance" with the emission standards being set in the CPP by allowing utilities to purchase decoupled wind energy RECs from Oregon, with no practical means of power delivery. There is ample basis to focus on the state where power is delivered into meaningful commerce, as opposed to the site in which the energy resource originates. For example, with respect to natural gas, most people would consider it absurd to credit emission reductions from higher dispatch of natural gas power plants in Alabama to the wells of Texas or Pennsylvania from which the fuel is produced. Similarly, the wind turbines of Oklahoma may deliver power via HVDC transmission to the high voltage AC systems in Tennessee and onward to Alabama, where they provide the actual benefits of use as well as the reduction in emissions from local coal plants.

What we suggest to avoid double-counting and incentivize a reasonable correspondence between generation and consumption of renewable energy is the following:

- The general standard of crediting for renewable energy in the CPP should be a REC, with standards for state verification set by the EPA to ensure that RECs may not be double-counted.
- The RECs presented to the state for compliance should be either associated with the interconnect region (Eastern, Western or ERCOT) served by the utility, or should include documentation that ensures that the RECs are properly associated with power transferred from one interconnect to the other.
- The state should <u>also</u> require utilities to provide evidence, and evaluate outside evidence, to reasonably estimate the amount of actual power from renewable energy resources that was actually delivered to the utility system and used by the customers it serves. The standard of review should be sufficiently flexible that the state does not need to prove one-to-one correspondence between RECs and power delivery, but there should be a showing that regardless of origin, renewable energy is being delivered to the state and thus meaningfully and directly impacting the state's adjusted emissions rate.

EPA has specifically requested comments on allocating RE targets at a regional, rather than state level. Our opinion is that this will add unnecessary complexity. We believe that the

UCS Approach provides an adequate basis for establishing state targets, but that, as noted above, our suggestion is that states verify the RECs, and that the states verify that the RECs presented by the utilities to demonstrate compliance are associated with any portion of the interconnect in which they participate. Using RECs will avoid confusion or conflict between states with major renewable energy generation activities and the states that import that power.

Several utilities, including Alabama Power and Georgia Power, are already purchasing wind energy from Oklahoma and Kansas. As an option in those power purchase agreements, those utilities are retaining the RECs from the wind power purchased. Utilities purchasing delivered renewable energy, as well as the RECs, should be credited as such for compliance purposes.

Rather than using a regional REC compliance target, we would favor the power delivery review that we suggest as a method to ensure that states provide guidance and incentives that ensure delivery of renewable energy to their states while facilitating continued commerce in energy among the states. This power delivery review will encourage regionalization while avoiding the inevitable severing of single utilities with integrated planning, transmission and distribution systems into multiple regions. For example, Tennessee Valley Authority serves seven states, including states that are also served by other utilities integrated into a regional transmission organization. There is simply no straightforward subdivision of the 50 states into specific regions that does not involve severing integrated utilities or balancing authorities into multiple regions.

EPA should also evaluate this issue to ensure there is no double-counting resulting from power transfers in or out of states with mass-based emission targets depending on how EPA decides to assign RECs and evaluate power transfers.

3. Energy Efficiency Resources in the Southeast

SACE appreciates the opportunity to comment, and support the use of Building Block 4, demand-side energy efficiency for state CPP compliance. Energy efficiency is the lowest cost resource available to states to comply with the EPA's CPP, and states should maximize the use of energy efficiency in their compliance plans. This is particularly true in the Southeast, where SACE focuses its efforts. The Southeast has the lowest incomes on a national basis, but the highest percentage of income going to utility bills. By investing in energy efficiency, states reduce carbon pollution, lower utility bills, create jobs and grow their local economy.

In this section, SACE responds to EPA's request for comments regarding: a) annual energy efficiency goals; b) CPP compliance start date; c) data sources for EE costs; d) EM&V guidance; e) the impact of the rule on municipal and cooperative utilities; and f) net importing states.

a) *Annual energy efficiency goals should ramp up 0.25% a year to reach 2.0% annual incremental savings.*[67]

[67] The EPA asked for comment on increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34875 (June 2, 2014).

SACE recommends an annual incremental efficiency rate of 0.25 percent per year, ramping up to two percent annually because EPA's methodology for establishing state baselines and ramp rates is conservative; and because all energy efficiency should be eligible for state compliance plans.

i) Current EE goal setting methodology is overly conservative.

EPA set each state's recommended incremental energy savings levels for 2017 equal to the savings levels reported on the EIA Form 861 for the year 2012. This results in a low starting point and a low overall impact for energy efficiency toward the interim and final emission-reduction goals. Furthermore, it does not comport with EPA's reasonable assumption that utilities should be able to grow their incremental energy savings each year.

By not including any growth assumption for the five years between 2012 and 2017, EPA significantly reduced the energy savings targets for every state. For the five years from 2017 to 2022, EPA assumed that total U.S. energy savings could grow from 0.56% of sales – the 2012 level – to 1.33% of sales, representing a 0.2% annual ramp rate. If EPA were to assume the same ramp rate for the five-year period from 2012 to 2017, the 2017 levels would be nearly two-and-a-half times as high.

Some may argue that EPA should not assume what might be considered "early action" prior to 2017. However, many states are already pursuing energy efficiency programs for a variety of reasons. It would be unreasonable for EPA to base its targets on the unrealistic assumption that every state and every utility is taking a five-year hiatus from action.

ii) All EE should be eligible for state compliance plans.

The EPA requested comment on the use of a variety of energy efficiency technologies as compliance tools in the proposed rule. SACE recommends that all energy efficiency that is additional and reduces carbon emissions should be eligible for state compliance plans. This includes building energy codes[68] and appliance standards, combined heat and power,[69] and more difficult to quantify efficiency, such as behavioral programs. Further, SACE recommends that the EPA should not limit the energy efficiency resources that states can use in their compliance plans because the savings are difficult to quantify.

By including all energy efficiency as compliance tools, states should easily be able to achieve 0.25% annual energy savings, ramping up to 2%. A recent analysis by ACEEE found that four energy policies could save over 700 million GWh of electricity by 2030.[70] Of these policies, building codes were projected to save 17% of the impacts, and CHP was projected to save 7% of the impacts.

[68] If we were to capture the potential for additional policies, such as the adoption and enforcement of state or local building energy codes, to contribute additional reductions in electricity demand beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5%. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34872 (June 2, 2014

[69] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34924 (June 2, 2014).

[70] Sara Hayes, et al, Am. Council for an Energy-Efficient Economy, Change is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution (April 2014), available at http://aceee.org/research-report/e1401

b) Use of Savings Achieved after Proposed Rule Announced for Compliance is Appropriate.[71]

The EPA proposed that reductions that occur as a result of energy efficiency programs that are adopted before the performance period, beginning in 2020, count towards compliance as long as they were adopted after the proposal date. EPA is also taking comment on other cut-off dates. SACE supports the EPA's proposal to allow reductions that occur after the proposal date.

If the EPA uses 2012 savings as the baseline for 2017 goals, it is critical to allow measures that are put in place after June 18, 2014, that are still in service in 2020 to count towards state compliance. Due to the very low goals that are created by this methodology, it is important to create an incentive for states (and utilities) to maintain the energy efficiency infrastructure that has recently been established in the Southeast. If states cannot count early efficiency actions for compliance, there will be a perverse incentive for states and utilities to reduce their program offerings today in order to allow for easier capture of savings in 2020.

Further, SACE believes that allowing states to count efficiency from the proposal date (assuming the measure life still exists in 2020) will encourage states to take advantage of the opportunity to use more efficiency to meet their goals. This will keep compliance costs low, create and maintain local jobs, and increase the quality of life, comfort, and productivity in the built environment.

If EPA agrees with our proposal to begin the growth assumption in 2013, it may be reasonable to count energy efficiency programs beginning after 2012 towards state compliance plans. This would be similar to the treatment of "under construction" power plants.

c) Alternative approaches and/or data sources for evaluating costs associated with implementation of state demand side energy efficiency policies. FR 34875

SACE's review of recent cost literature and review of cost recovery filings in state regulatory proceeding indicates that the cost assumptions the EPA used for energy efficiency compliance appear to be very conservative, and subsequently, quite high. SACE has three specific recommendations for EPA regarding its CSE calculations: (1) update its cost estimates based on the 2014 ACEEE report, resulting in a 2017 first year net cost of $230 per MWh and a 2017 levelized cost of 2.8 cents per kWh[72]; (2) eliminate cost escalation for years when incremental energy savings are less than 2.5%; and (3) utilize the 11-year measure life in the 2014 ACEEE report.

[71] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34918 (June 2, 2014). While proposing that the ''specified date'' would be the date of proposal of these emission guidelines, the EPA also requests comment on the following alternatives: The start date of the initial plan performance period, the date of promulgation of the emission guidelines, the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date.

[72] Maggie Molina, Am. Council for an Energy-Efficient Economy, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (Mar. 2014), available at http://aceee.org/research-report/u1402

While we note that EPA was deliberately conservative in setting the cost of energy efficiency, SACE applauds EPA for its thoughtful analysis and integration of relevant energy efficiency cost studies into the proposed CPP.

i) EPA's cost estimates are excessively high due to the use of outdated cost data.

In crafting the CPP goals, EPA adopted a conservative estimate of the cost of energy efficiency. However, even with this higher-than-average cost assumption, energy efficiency is still the cheapest of all of the compliance options. EPA estimated that the average program levelized cost of saved energy (CSE) would range from 4.07 cents per kWh in 2017 to 4.51 cents per kWh in 2030.[73] To arrive at these values, EPA utilized an average first-year net cost of $275 per MWh, which was the cost determined in a 2009 ACEEE report. EPA noted "two recent national analyses have found lower program costs than the 2009 ACEEE study,"[74] including a 2014 update to the 2009 ACEEE report and a 2014 study from the Lawrence Berkeley National Laboratory (LBNL)[75].

The 2014 ACEEE study found average first-year net costs of $230 per MWh. The 2014 updated ACEEE report also found that the average levelized cost of energy efficiency programs from 2009 to 2012 was 2.8 cents per kWh, which was roughly one-third to one-half of the cost of fossil-fuel generation options considered in the study.[76] The 2014 LBNL study focused on gross rather than net savings, and found the average first year cost of gross savings to be $162 per MWh. To compare this to net savings, EPA applied a net-to-gross ratio of 0.9 and deflated costs at 3%, resulting in a $175 per MWh average first year cost of net savings.

EPA notes that based on the 2014 ACEEE study and the 2014 LBNL study, the value "used for this analysis is conservative, resulting in comparatively higher total costs than would be the case based upon the newer studies."[77] However, it is not clear why EPA did not adjust its cost estimates to reflect the latest data. The $275 per MWh first-year cost utilized by EPA is 20% higher than the latest ACEEE cost finding and 57% higher than the EPA-adjusted 2014 LBNL cost finding.

Other recent reports have also found the cost of energy efficiency to be lower than the EPA estimates. For example, a 2014 report by Lazard indicates that the levelized cost of energy efficiency ranges from 0-5 cents per kWh, as shown in Figure 4, below.[78] Lazard's analysis shows that energy efficiency significantly more cost effective than CO2-emitting generating

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[73] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures, Data File: GHG Abatement Measures, Appendix 5-4.xlsx

[74] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-51. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[75] Billingsley, M. A., I. M. Hoffman, E. Stuart, S. R. Schiller, C. A. Goldman, K. LaCommare. March 2014. The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs. LBNL-6595E. Available at http://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf

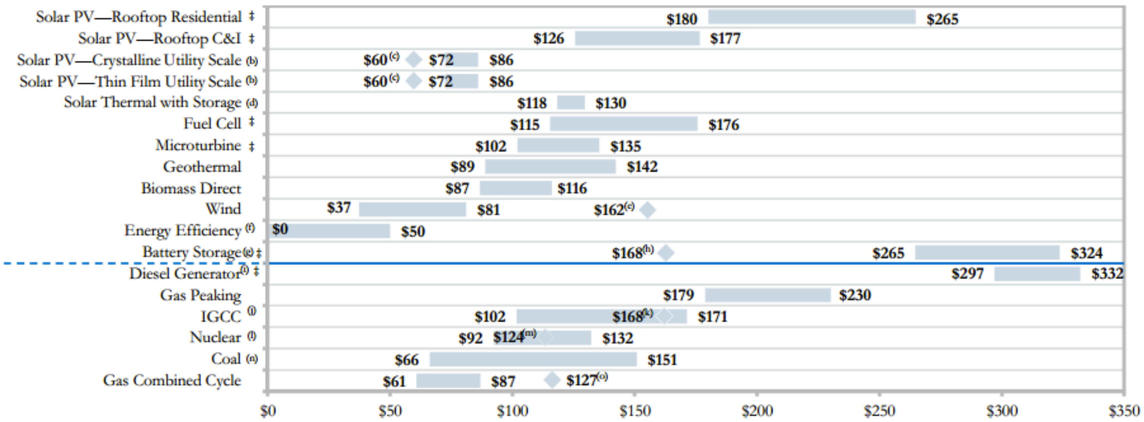
[76] Maggie Molina, Am. Council for an Energy-Efficient Economy, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (Mar. 2014), available at http://aceee.org/research-report/u1402

[77] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-51. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[78] Lazard's Levelized Cost of Energy Analysis – Version 8.0, September 2014, Available at http://www.lazard.com/PDF/Levelized Cost of Energy - Version 8.0.pdf

resources, with the levelized cost of fossil fuel generation ranging from just over 6 cents per kWh for the most efficient combined-cycle gas plants, all the way up to more than 33 cents per kWh for the least efficient diesel generators.

Figure 4. Levelized Cost of Energy Efficiency[79]



Further, Southeastern utilities are also projecting and achieving energy efficiency cost that are lower than the costs utilized by EPA. For example, in the most recent update to the demand-side management portion of its 2013 IRP Georgia Power expects to achieve savings at 1 cent per kWh for years 2013 through 2023.[80] This builds on their recent experience from 2011-2013 where Georgia Power implemented efficiency at a levelized cost of $0.01/kWh.[81] Duke Energy Carolinas achieved significant savings – upwards of 0.5% of retail sales at a levelized cost of $0.01 per kWh from 2009 through 2013.[82]

Investor-owned utilities are not alone in achieving energy savings in excess of the 2017 levels recommended by EPA. In 2013, the Tennessee Valley Authority (TVA) reported 0.38% gross savings as a percentage of prior year sales, with an average lifetime cost of 1.8 cents per kWh.[83] By comparison, EPA is recommending that Tennessee save 0.3% in 2017 at a levelized cost of 3.25 cents per kWh. While TVA does not operate solely in Tennessee, it does provide power to nearly the entire state, and its cost of savings is lower than the costs established by EPA for any of the seven states TVA serves.

Based on this information, SACE recommends that the EPA update its cost estimates based on the 2014 ACEEE report, resulting in a 2017 first year net cost of $230 per MWh and a 2017 levelized cost of 2.8 cents per kWh.

[79] Figure 4 shows the unsubsidized levelized cost of energy for each resource.
[80] Georgia Public Service Commission, Docket No. 36499. Georgia Power Company's Application for the Certification of its Amended Demand Side Management Plan. Appendix E, Summary of DSM Program Economics. January 2014.
[81] Georgia Public Service Commission, Docket No 31082. Fourth Quarter 2011, 2012, and 2013 Status Report. Based on conversation with Company, assume 10 year lifetime for portfolio.
[82] NC Utility Commission, Docket No. E7 Sub 1050. Direct Testimony of Duke Energy Carolinas Witness Tim Duff. Based on conversation with Company, assume 10 year lifetime for portfolio
[83] Tennessee Valley Authority, EnergyRight Solutions Highlights Report 2013 at 35. Available at http://www.energyright.com/pdf/highlights_2013.pdf

ii) EPA's cost escalation is inappropriate for projected EE impacts.

EPA has applied a 0% escalation rate when first-year savings as a percentage of sales are less than 0.5%, a 20% escalation rate when first-year savings are between 0.5% and 1.0%, and a 40% escalation rate when savings are greater than 1.0%. EPA mentioned two studies it considered in establishing its cost escalation methodology. The first was an LBNL analysis that suggested decreasing costs at savings levels up to 0.5%, leavings costs constant for savings between 0.5% and 1.5%, and increasing costs at savings levels above 1.5%.[84] The second was a 2014 ACEEE report, which EPA notes "provides weak statistical support for a cost increase of 20% when going from 0.5% to 1.0% savings rate and an additional cost increase of 20% when going from 1.0% to 1.5% savings rate."[85] EPA relied upon the more conservative ACEEE report in establishing its cost escalation rates, despite the weak statistical correlation. However, in the report, ACEEE noted, "these findings cast doubt on the hypothesis that programs with higher electricity savings levels are associated with higher CSE values."[86]

Other studies suggest much less cost escalation than that which was adopted by EPA. For example, a study by Green Energy Economics Group presented at the 2012 ACEEE Summer Study on Energy Efficiency in Buildings, indicates that program costs do not increase – and in fact decrease on a per unit savings basis – until savings reach 2.5% per year.[87] A 2008 report by Synapse Energy Economics concluded, "this analysis of actual program CSE finds that program CSE seems to decrease as program scale and impact grows."[88] In addition, a separate 2008 report by Synapse Energy Economics on energy efficiency programs in Massachusetts concluded, "the cost of saved energy could decrease if the utilities were to increase their program scale further, perhaps up to the level of annual savings equal to 2% or 3% of annual sales."[89]

All of the studies support a cost escalation beyond 2.5% of annual sales. However, below 2.5% of annual sales, the studies vary between cost decreases and weak evidence for cost increases. Accordingly, SACE recommends that for years with EE savings forecast below 2.5% of annual sales, costs be held constant in real terms, but for years with EE above that level, an escalation rate should be adopted.

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[84] Barbose, G. L., C.A. Goldman, I. M. Hoffman, M. A. Billingsley. 2013. The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025. January 2013. LBNL-5803E. Available at http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend

[85] Maggie Molina, Am. Council for an Energy-Efficient Economy, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (Mar. 2014), available at http://aceee.org/research-report/u1402

[86] Maggie Molina, Am. Council for an Energy-Efficient Economy, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (Mar. 2014), pg. 37, available at http://aceee.org/research-report/u1402

[87] John Plunkett, Theodore Love and Francis Wyatt, Green Energy Economics Group, An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application, 2012 ACEEE Summer Study on Energy Efficiency in Buildings, http://www.aceee.org/files/proceedings/2012/data/papers/0193-000170.pdf

[88] Takahashi, K. and D. Nichols. 2008 "The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date." In *Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings.* Washington, DC: ACEEE. Available at https://www.aceee.org/files/proceedings/2008/data/papers/8_434.pdf

[89] Doug Hurley, Kenji Takahashi, Bruce Biewald, Jennifer Kallay, and Robin Maslowski. Synapse Energy Economics Inc. "Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts." Page 14. August 2008. Prepared for: Northeast Energy Efficiency Council.

iii) EPA should adopt a less conservative approach to factoring measure lifetimes into its calculation of the levelized costs of saved energy.

In developing the levelized CSE utilized to develop the state goals in the CPP, EPA utilized a conservative average measure lifetime of 10 years and an unconventional and conservative approach to integrating measure lifetime into the cost calculations.

In the aforementioned 2009 ACEEE cost of efficiency report, the average measure lifetime was found to be 13 years. Measure lifetimes were lower in the 2014 ACEEE report, which EPA referenced in Table 5-10.[90] In the 2014 ACEEE report, the CSE calculations are based on actual measure lifetimes where reported, and based on an 11-year average measure lifetime for states that did not provide measure lifetime data. EPA noted, "other studies have found slightly higher values for average measure life for EE portfolios, ranging from 10 to 13 years," and cited the 2014 LBNL report.[91] EPA further noted, "our assumption of 10 years is conservative by comparison and leads to lower cumulative impacts over time and correspondingly lower state goals."[92] SACE recommends that EPA utilize the 11-year average measure lifetime determined in the 2014 ACEEE report.

EPA also adopted an unconventional approach to calculating the levelized CSE by assuming "an even distribution from one year in length to two times the average measure life (twenty years) in length."[93] EPA states that this approach is generally supported by LBNL's use of an interquartile range in a 2014 report, but also notes "the more common approach in other studies is to assume a portfolio with no diversity of measure lives whatsoever, with the entirety of incremental savings being realized each year from the first through the full average measure life and then dropping to zero in the following year."[94] EPA further notes: "our approach is a conservative one, leading to the same quantity of total energy savings, but with a greater portion of the savings occurring in later years than occurs with the more common, and simpler, approach. This results in lower cumulative impacts in earlier years and correspondingly lower state goals through 2030."[95]

SACE recommends that EPA update its CSE calculations to reflect the data and methodology found in the 2014 ACEEE report. This would ensure that savings calculations are consistently reflective of the latest data and best practices from ACEEE, upon whose

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[90] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-36. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[91] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-36. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[92] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-36. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[93] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-36. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[94] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-37. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[95] United States Environmental Protection Agency, (2014) Technical Source Document: GHG Abatement Measures at p5-37. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

research EPA has leaned considerably in developing the energy efficiency goals set forth in the draft CPP.

d) *EPA guidance on Evaluation, Measurement &Verification (EM&V) methodologies is necessary, despite the wealth of existing knowledge.*

SACE commends and supports EPA's proposal to require EM&V plans for energy efficiency compliance. SACE has signed on to separate EM&V comments with many other energy efficiency experts.[96] These comments reflect our stance on many issues. There is one additional issue that SACE would like to highlight that is not part of our joint comments. SACE recommends that EPA should provide guidance on how to convert the state net energy savings calculations to gross savings.

In the proposed rule, the EPA calculated the energy efficiency goals based on net savings.[97] SACE, and many other efficiency experts recommend that the EPA should accept adjusted gross savings.

While SACE is aware that the building block calculations are used only to determine state goals, and the particular data inputs used in the goal setting process are not intended to represent specific requirements. However, given our recommendation to allow state energy efficiency compliance to be measured as adjusted gross savings, SACE recommends that the EPA provide a net-to-gross ratio so that states may convert their net savings goal to a gross savings goal.

e) *The proposed CPP will not adversely impact municipal and cooperative utilities.*[98]

Building Block 4 is the primary compliance block that distribution-only utilities, including many public power entities, would directly control and administer, but based on CPP comments filed through November 28, 2014 by the American Public Power Association (APPA) and National Rural Electric Cooperative Association (NRECA), it is not clear whether municipal utilities and rural cooperatives are fully considering the benefit or potential for energy efficiency in the CPP.

In the Southeast, municipal and cooperative utilities are achieving savings higher, or comparable to savings reported by investor-owned utilities in nearby territories. For example,

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[96] *See* Joint Energy Efficiency Stakeholder Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014) – Concerning Evaluation, Measurement and Verification, Reporting Requirements and Guidelines for Energy Efficiency, Re: Docket ID No. EPA-HQ-OAR-2013-0602. Nov. 26, 2014.

[97] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg. 34872 (June 2, 2014). Footnote 180. "This incremental savings rate and all others discussed in this subsection represent net, rather than gross, energy savings. Gross savings are the changes in energy use (MWh) that result directly from program related actions take by program participants, regardless of why they participated in a program. Net savings refer to the changes in energy use that are directly attributable to a particular energy efficiency program after accounting for free-ridership, spillover, and other factors."

[98] United States Environmental Protection Agency, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emissions Standards for Modified and Reconstructed Power Plants, at 7-5. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf

among the local power companies served by TVA, the leaders are achieving annual incremental energy savings between 1.15% and 3.52% of sales.[99]

Table 6. TVA Energy Right Solutions 2013 Incremental Gross Energy Savings

Top Local Power Company Performers	MWh	% of Fiscal Year Sales Total
Smithville Electric System (TN)	4,353	3.52%
Franklin Electric Plant Board (KY)	4,793	2.43%
Newbern Electric Water & Gas (TN)	2,898	2.41%
Sparta Electric & Public Works (TN)	2,595	2.13%
Fort Payne Improvement Authority (AL)	5,757	1.81%
Lexington Electric System (TN)	8,177	1.76%
Winchester Utilities (TN)	3,009	1.65%
Alcorn County Electric Power Association (MS)	7,864	1.22%
Ripley Power and Light (TN)	2,411	1.20%
Tuscumbia Electricity Department (AL)	1,135	1.15%

As discussed in our joint EM&V comments with several organizations including ACEEE, NEEP, and NRDC, states with limited EE program and evaluation experience should be allowed to use deemed savings values borrowed from other states or regions to quantify savings for measures/programs installed during 2016-2019.

One area in which many municipal and cooperative utilities hold an advantage in achieving energy savings is the availability of public funding for financing energy efficiency. In particular, the United States Department of Agriculture's grant and loan programs through the Rural Utility Service offer low-cost opportunities for energy efficiency funding. Among these grant and loan programs are the Energy Efficiency and Conservation Loan Program (EECLP), the Rural Economic Development Loan and Grant Program, and the Rural Energy Savings Program. In the final rule for the EECLP, RUS states that "the energy efficiency program should compete equally with other eligible loan purposes" for the overall electric program, which is authorized to issue more than $6 billion in loans at U.S. Treasury rates each year.[100] In general, eligible utilities include existing Rural Utility Service borrowers, and electric cooperatives and municipal utilities with a majority of their meters outside of

[99] Tennessee Valley Authority, TVA Energy Right Solutions Highlights Report 2013 at 35, available at http://www.energyright.com/pdf/highlights_2013.pdf
[100] United States Department of Agriculture, Electric Program Loans and Grants, Available at http://www.rurdev.usda.gov/UEP_Loans_Grants.html

municipalities with populations greater than 20,000.[101] It is our understanding that most of the 2,000 municipal utilities nationwide serve populations small enough to meet that test.

One of the most cost-effective uses of EECLP funds, which can yield very high levels of savings, is establishment of low-interest rate on-bill financing programs. On Oct. 23, 2014, Agriculture Secretary Tom Vilsack announced that USDA has awarded EECLP loans of $6 million to North Carolina's Roanoke Electric Membership Corporation and $4.6 million to North Arkansas Electric Cooperative. In addition, a group of Tennessee's electric cooperatives are planning what could be the first statewide EECLP-funded on-bill financing program, and held a program design planning retreat on Sept. 5, 2014 that was sponsored by the National Governors' Association. Cooperative-run on-bill financing programs have shown potential for achieving significant savings. For example, the "Help My House" Rural Energy Savings Program developed by cooperatives in South Carolina has reduced participants' electricity usage by an average of 34%.[102] The program utilizes funds from the USDA's Rural Economic Development Loan and Grant Program, and provides 10-year, 2.5% interest rate loans to customers for "whole house" efficiency upgrades.

Another advantage municipals and cooperatives hold is not having a fiduciary obligation to shareholders to grow profits. However, as noted in a 2014 ACEEE report, management compensation is often based on financial performance, and in some cases, "public utilities that are part of municipal and other government agencies are in fact profit centers whose surplus of revenues over expenses keeps taxes and other public exactions lower than they would be otherwise."[103]

While the nonprofit status of public power entities generally means that financial incentives for energy efficiency implementation are not needed, municipal and cooperatives still must ensure that service costs are being recovered through rates.[104] In most cases, fixed costs are recovered in part through variable charges on customers' bills, so a reduction in sales can potentially result in unrecovered costs. This issue, often referred to as "lost revenues," is a common concern among management of municipal and cooperative utilities considering energy efficiency initiatives. There are several methods to mitigate the impact of lost sales revenue on the recovery of fixed costs, including rate adjustments that reflect the increase of fixed costs across fewer kilowatt-hours being sold (and purchased if it is a distribution only utility).

f) Net importing states should not receive a downward adjustment in energy efficiency credits.[105]

EPA is proposing an adjustment of electricity savings credits downwards in net electricity importing states because some of the CO_2 emissions reductions are likely to occur out of

[101] United States Department of Agriculture, Rural Electrification Loans and Loan Guarantees, Electric Loans and Loan Guarantees, Number: 10.850, available at https://www.cfda.gov/index?s=program&mode=form&tab=core&id=6357daaff64e736b0aba22dc859c4b55

[102] Keegan, Patrick. Help My House Program Final Summary Report. 2013. Prepared for Central Electric Power Cooperative, Columbia, South Carolina, and The Electric Cooperatives of South Carolina, Cayce, South Carolina. Available at http://www.cepci.org/assets/HelpMyHouseFinalSummaryReport_June2013.pdf

[103] ACEEE, The Future of the Utility Industry and the Role of Energy Efficiency. Available at http://www.aceee.org/sites/default/files/publications/researchreports/u1404.pdf

[104] American Public Power Association, Public Power Magazine, July/August 2009 Edition, Reconciling Energy Efficiency Programs and Revenue Adequacy, available at http://www.nxtbook.com/nxtbooks/naylor/APPH0509/index.php?startid=12 - /14

state. However, EPA is not proposing a comparable upwards adjustment in savings credits in net exporting states. The EPA has requested comments on this proposal.

SACE, along with other organizations, recommends that there be no adjustment as long as both the importing and exporting state select rate-based goals, meaning that the state where the electricity savings occurs should get full credit for the energy savings in that state.[106] This convention should be used in both determining state goals and in compliance with goals under a rate-based approach. States that choose the emissions rate approach should get full credit for electricity savings occurring in the state, and should not be required to track savings back to actual power plants or determine CO_2 emissions reductions due to electricity savings.

There is a legitimate concern, however, if a state chooses a rate-based approach and gets full credit for energy savings achieved in the state, but then imports a significant amount of electricity from a state that chooses a mass-based approach. This in effect would double count the portion of the energy savings (and the emissions reductions resulting from the savings) that results in reduced generation out-of-state. It would be reasonable for the EPA to require an energy savings adjustment within the state where the savings occurs in this case. The EPA could set a threshold for applying an adjustment factor during the implementation phase (e.g., it is required if a state that chooses the rate-based approach imports more than 5% of its electricity from a state that chooses the mass-based approach in any particular year).

It should also be noted that this is not an issue if a state chooses the mass-based approach for compliance. In this case, emissions reductions will occur where they occur and compliance will be based on actual emissions, not on a computation of emissions. There are no energy efficiency credits if a state chooses mass-based compliance, and thus no adjustment for electricity import/export.

4. Nuclear Energy and Associated Compliance Risks

Although SACE recognizes the “carbon-zero” classification of nuclear energy generation in EPA’s draft CPP, we recommend that EPA determine that nuclear generation should not be an acceptable control measure for purposes of state compliance with a BSER standard. We contend that nuclear generation is a control measure that will generally fail to meet EPA’s criteria for a state plan to be approvable.[107] If EPA finds that nuclear generation is not practically enforceable, and thus ineligible for inclusion in a state compliance plan, then it follows that it should not be included in the building blocks. Additionally, we believe that the costs associated with nuclear energy generation as a control technology under the BSER building block framework are unreasonable and far exceed costs of other technologies included in the BSER. Therefore, we also recommend EPA remove nuclear generation as a compliance option under BSER.

Below, we a) discuss why EPA should decide not to accept nuclear generation as an emission reduction measure for purposes of compliance with a BSER standard and the evidence that EPA, in determining BSER, should consider in its analysis of the energy impacts of nuclear

[105] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg. 34896-97, 34922. (June 18, 2014).
[106] See comments by SWEEP, for example.
[107] 42. U.S.C. 7411(a)(1).

generation, including b) overall concerns and cost implications for nuclear energy generation; c) cost implications of under construction nuclear generation; d) the risks of a perverse incentive to perpetuate or revive operation of nuclear reactors and e) additional non-air quality impacts from nuclear energy. We elaborate on these additional public health, safety and environmental impacts of nuclear energy generation in Attachment B.

Cumulatively, the issues raised in Section (b) through (e) indicate that the additional costs of using nuclear generation as a control measure are substantially higher than EPA evaluated in the draft rule. If EPA includes all of these costs of using nuclear energy as a compliance option in a state plan, as explained below, then it is clear that nuclear energy does not meet the cost effectiveness threshold for BSER.

a) Enforceability concerns with nuclear generation as an emission reduction measure

Like renewable energy and demand-side energy efficiency measures, new or extended nuclear generation is a measure that does not apply to affected EGUs. Also like RE and demand-side EE measures, new or extended nuclear generation may be implemented by the state (in the form of a Public Utility Commission) or by another entity assigned responsibility by the state such as an electric utility, most commonly both. But unlike those other measures, nuclear generation is subject to the authority of the Nuclear Regulatory Commission (NRC).

EPA is seeking comment on whether "the state plan must include additional measures that would apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance."[108]

In the event of noncompliance, EPA should find that it would be impractical to take enforcement action against some responsible parties. Based on the history of nuclear power, it is likely that nuclear projects are subject to substantial cost risk, numerous and extensive schedule delays, and unavoidable and lengthy outages due to operational limitations and safety concerns. Each of these circumstances is likely to lead to a failure to achieve the required level of emission performance.

In its evaluation, EPA should evaluate the unique character of the responsible parties with the authority to expedite, delay or cancel nuclear projects. The NRC has statutory responsibilities to ensure the safe operation of nuclear power plants. EPA should evaluate whether the NRC could be compelled to grant or extend an operating license to a nuclear reactor in order to implement the measures of a state compliance plan. If the NRC refuses over the objection of other responsible parties, EPA should determine what obligation those other responsible parties would have to implement additional measures to achieve the required level of emission performance.

Given the singular magnitude of emissions reduction associated with a single nuclear unit (as compared to a single wind turbine, for instance), it is implausible to expect that a state plan could practically maintain a sufficient inventory of cost-effective measures that could be triggered in a timely manner to effectively address the failure of a nuclear reactor to achieve the required level of emission performance. EPA has asked several questions regarding the steps that should be taken "if reporting shows that the plan is not achieving the projected level of emission performance."

[108] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34909 (June 2, 2014).

EPA has previously recognized that emission control strategies that rely on voluntary actions of individuals and other parties (e.g., the NRC) may be considered "innovative methods in achieving emission reductions."[109] For such methods, EPA approval obligates the state to assure that the emission reductions occur.

In the case of the Voluntary Emission Reduction Program (VMEP), EPA recognized that the state's obligation to "remedy any shortfalls from forecasted emission reductions in a timely manner" created a necessity to limit the contribution of such methods to a maximum of "three percent of the total reductions needed to meet any requirements."[110] Almost any individual nuclear generation project is likely to exceed a "three percent" benchmark. EPA should not allow a single project, subject to the authority of the NRC or any other party not subject to enforcement action pursuant to the Clean Air Act, to make up more than three percent of a state compliance plan.

In the event that such a large project failed to achieve the required emission reductions, the delay in implementing an alternative could make it difficult for the state to ever catch up at a reasonable cost. For example, if EPA were to allow a state to then adopt new plan measures and resubmit the plan to the EPA for review and approval, years of excessive emissions would accrue. It would further compound this shortfall if the process were not triggered until "the end of a multi-year plan performance period if emission performance is not met." For smaller emissions reduction measures, such as the failure of a single energy efficiency program, or renewable energy project, a report-and-correct process could be timely enough due to the smaller scale. But if EPA views three percent as a threshold for accepting responsible parties beyond the reach of enforcement under the Clean Air Act, then at the scale of a nuclear generation plant, EPA should certainly appreciate the need for immediate implementation of corrective measures upon a failure to achieve the required level of emission performance. Yet for reasons discussed below, such contingencies could have excessive costs.

b) Overall Concerns and Cost Implications of Nuclear Energy

In evaluating whether nuclear generation is a cost-effective option in the BSER framework for reducing carbon emissions, EPA failed to consider the full range of costs of nuclear generation as a control technology. There are several categories of costs associated with using nuclear generation in BSER as a compliance method. EPA has generally underestimated the general construction and operation costs to build nuclear generation, as demonstrated by the trend of cost overruns at projects under construction. Furthermore, the costs to provide backup generation when a nuclear reactor goes offline along with the costs of securing standby control measures for reducing carbon emissions in a state plan are far higher than the costs to backup other BSER control technologies like solar and wind generation. Finally, the costs to mitigate water and other resource use, clean up any environmental harm, and address public health harm caused by nuclear generation are significant. Even if EPA views nuclear generation as practically enforceable, these incremental costs of nuclear generation to utility customers and to society in general are, cumulatively, far greater than any incremental costs associated with cleaner and safer alternatives.

[109] US Environmental Protection Agency, "Commuter Programs: Quantifying and Using Their Emission Benefits in SIPs and Conformity," EPA-420-B-14-004 (February 2014).
[110] *Id.*

Nuclear energy generation is an expensive, water-intensive and risky energy choice when compared to other low carbon-emitting options within Building Block 3, namely renewables such as wind and solar PV. By including nuclear energy in Building Block 3, EPA is effectively diverting resources away from the most cost-effective technologies for reducing carbon emissions and towards an unsafe energy resource. Nuclear reactors produce toxic, extremely long-lived, highly radioactive waste for which no safe storage or management yet exists, require massive amounts of water to operate and can have catastrophic human, environmental and economic consequences should a severe accident occur.

If EPA includes nuclear energy as a compliance option, states that rely significantly on nuclear energy for compliance will face serious challenges in meeting carbon emission reduction goals. Nuclear reactors go offline or scale back power for various reasons, many of which are outside of a state's control. As explained further in Section 4(e) below, droughts or summer heat waves can affect the water supply on which a reactor relies to provide adequate cooling water and ensure safe operation of the plant. Not enough water may be available, water supplies may be already too hot for reactor use, or the water being discharged by the plant may violate thermal discharge limits.

States have no authority to direct operational decisions made by the Nuclear Regulatory Commission (NRC) as the primary regulator of nuclear reactors. As stated in Section 4(b)(iii), nuclear accidents or safety concerns can have fleet-wide implications that are outside of state regulatory control. It is reasonably foreseeable that regulatory decisions made by the NRC regarding safety issues could prevent compliance with the CPP if nuclear energy is included in a state's compliance plan.[111]

i) Cost Implications Related to New Nuclear Reactors

Present-day examples confirm that nuclear generation is expensive. Currently all five reactors under construction in the U.S. (TVA's Watts Bar 2 in TN; Southern Company's Vogtle 3 & 4 in GA; and SCANA/SCE&G's V.C. Summer 2 & 3 in SC) have experienced significant cost increases and scheduling delays.[112] These examples alone provide ample evidence of why nuclear energy generation cannot be viewed as a "reasonable cost" carbon-reduction option.

Proposed reactors, not yet under construction, have also experienced serious and costly delays including suspensions and cancelations. For example, Florida utilities have proposed up to four new nuclear reactors, all using the Toshiba-Westinghouse AP1000 design, located at two sites: Duke Energy Florida's (DEF) Levy County project (2 units) and FPL's Turkey Point 6 & 7 reactors (2 units). Both of these projects are severely over budget and delayed.[113]

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[111] In a September 16, 2014 letter to EPA, the Georgia Environmental Protection Division agreed with the assertion that including nuclear as a compliance tool reduces overall compliance flexibility, stating "The proposed rule's treatment of under-construction nuclear eliminates state flexibility in achieving the goal and *is not compatible with other building blocks*" (emphasis added). Georgia Environmental Protection Division (EPD), Comments to EPA re: Docket ID No. EPA-HQ-OAR-2013-0602, Comment Topic: Removal of Under-Construction Nuclear from Emissions Performance Goal Computation, September 16, 2014. Available at http://www.georgiaair.org/airpermit/downloads/planningsupport/regdev/ghg/gaepd_ucnuclear_comments09162014.pdf

[112] The latter four are the Toshiba-Westinghouse AP1000 design.

[113] Neither DEF nor FPL has committed to building a reactor. DEF has essentially canceled the Levy Co. reactors at the state level before the Florida Public Service Commission, although it is continuing minimal

Families, business and those on fixed budgets have been negatively impacted due in part to state legislation that allows utilities to charge customers in advance for costs associated with development of new reactors. In the case of the capacity expansion at DEF's Crystal River 3 reactor (which presumably could have counted towards Florida's state compliance plan), customers will not receive refunds for the canceled project. The costs associated with these projects in Florida have shown that new nuclear energy it is not a cost-effective option for utility customers.

ii) Cost Implications Related to Contingency Measures

At the scale of a nuclear generation plant, EPA must require that state compliance plans include immediate requirements for corrective measures upon a failure to achieve the required level of emission performance. Such a large inventory of "ready-to-go" contingency measures must be continuously maintained (e.g., if some measures are no longer feasible, or are not implemented, then new measures must be added). Due to the potential that these contingency measures were not selected for inclusion in the plan, and should not have lengthy development timelines so as to be available for immediate implementation, they would be more expensive than any measure in the plan that might be more methodically developed. The probability that such costs will be incurred should be considered as a component of the cost of nuclear power

c) Cost implications of under construction nuclear generation

Along with the high costs to develop new nuclear energy, the five under construction nuclear reactors will continue to require significant expenditures on the road to completion. EPA's assessment of new nuclear energy generation as a "reasonable cost" or "zero cost" option to reduce carbon emissions is not supported by the facts.[114] Furthermore, this assessment could inadvertently push states towards restarting canceled and uneconomic nuclear reactor proposals, such as Entergy's long-dormant plans at the Grand Gulf nuclear plant near Port Gibson, MS, or DEF's essentially-canceled Levy County reactors. All five of the under-construction nuclear reactors, TVA's Watts Bar 2 in Tennessee, Southern Company's Vogtle 3 & 4 in Georgia; and SCANA/SCE&G's V.C. Summer 2 & 3 in South Carolina, are located in the Southeast and demonstrate that the cost of new nuclear generation is not reasonable or zero.

i) Vogtle Units 3 and 4 - Georgia

The two proposed Toshiba-Westinghouse AP1000 reactors now under construction at Plant Vogtle have experienced significant cost increases and schedule delays. [115] In terms of scheduling, Vogtle reactor Unit 3 was originally scheduled to come online April 1, 2016 and

investments in its request for a combined operating license (COL) from the U.S. Nuclear Regulatory Commission.

[114] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg. 34870. (June 18, 2014).

[115] The history of Plant Vogtle illustrates the historical basis for rebutting the claim that the nuclear industry can learn from past delays and cost overruns. Initially, four reactors were originally considered for the Vogtle site, though only two were pursued. Original conceptual estimates from 1971 for the two-reactor plant indicated a cost of $660 million, but over a decade later the estimates for construction costs escalated more than twelvefold, to more than $8 billion. The reactors became operational in 1987 and 1989. The high costs resulted in the then-largest rate hike in Georgia's history. Southern Alliance for Clean Energy, *Code Red Alert: Confronting Nuclear Power in Georgia*, May 2004, p. 15. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf

reactor Unit 4 one year later, on April 1, 2017. Revised estimates, as stated in expert testimony in the combined 9th/10th semi-annual Vogtle Construction Monitoring (VCM) docket, are December 31, 2017 and December 31, 2018 respectively, representing a 21-month delay.[116]

Additional delays of 6 months or more have been indicated in filings during the 11th VCM, the most recent reporting period.[117] In fact, Georgia Public Service Commission Public Interest Advocacy Staff filed testimony on November 21, 2014 states that the 21-month delay scenario is an underestimate and that the Vogtle reactors will not come online at the end of 2017 and 2018:

> *The Staff and the CM [Construction Monitor] believe that the CODs [Commercial Operation Dates] will be further delayed. At this time, given the Consortium performance to date of significant delays in completing NI [Nuclear Island] activities, the lack of an IPS [Integrated Project Schedule] and the required compression activities that the Consortium intends to deploy, it is impossible to determine a reasonable forecast range as to when the Units could be commercially available. To be clear, Staff and the CM believe the Units will be delayed beyond current forecast CODs of December 2017 and 2018; however, we make no opinion regarding when the Units could be commercially available.*[118]

While the schedule has slipped significantly, the costs have increased substantially as well. Expert testimony before the Georgia Public Service Commission estimated that "…the average Total Project and Production Cost impact caused by a delay increases to approximately $2.0 million per day."[119] The initial certified cost for Georgia Power's share of the project was approximately $6.1 billion. With a 21-month delay, the Company's cost estimate has increased to approximately $6.8 billion.[120] As reported in the 11th Vogtle Construction Monitoring docket, Georgia Power has spent $2.8 billion in cumulative construction and capital costs as of June 30, 2014.[121] This means that Georgia Power has spent a little more than a third of the estimated project costs, leaving significant risk that costs will increase further. Georgia Power is 45.7% owner in the project, with the majority owned by three public utilities, Oglethorpe Power (30%), MEAG (22.7%) and the City of Dalton (1.6%). Apportioning Georgia Power's reported costs to the full ownership indicates that the original $14.1 billion Vogtle project now costs at least $15.5 billion.

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[116] Direct Testimony of Steven D. Roetger and William R. Jacobs, Jr., Ph.D., Docket No. 29849, Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Period, June 20, 2014, p. 7. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=153938

[117] Georgia Power Company, Docket No. 29849, 11th VCM, Response to STF-68-5, November 7, 2014. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=155696

[118] Direct Testimony of Steven D. Roetger and William R. Jacobs, Jr., Ph.D., Docket No. 29849, Eleventh Semi-Annual Vogtle Construction Monitoring Period, November 21, 2014, pp. 32-33. Available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=155941.

[119] Direct Testimony of Philip Hayet on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff, Docket No. 29849, Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Period, June 20, 2014, p. 21. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=153938

[120] Georgia Power, Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Report, Docket 29849, February 2014, Table 1.1, p. 31. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=152164

[121] Georgia Power, Direct Testimony of David J. Clem, Kyle C. Leach, and David L. McKinney in Support of Georgia Power Company's Eleventh Semi-Annual Vogtle Construction Monitoring Report, Docket No. 29849, October 17, 2014, p. 5. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=155466

Federal taxpayers and utility ratepayers bear most of the risk from schedule delays and cost overruns. In February 2010, $8.3 billion in federal conditional nuclear loan guarantees were offered to the Vogtle project. Georgia Power and Oglethorpe finalized $6.3 billion in loan guarantees in February 2014; MEAG has yet to finalize the remaining $1.8 billion.[122] The Georgia Nuclear Financing Act, passed in 2009, requires Georgia Power ratepayers to pay in advance for the financing costs associated with the new reactors.[123] Between January 2011 and September 2014, $1.0 billion has been collected from customers through the Nuclear Construction Cost Recovery rider (NCCR).[124] The NCCR rider is currently over 9.3% of a typical customer's bill.[125] The longer the project takes, the more ratepayers are paying for financing costs – placing the burden on Georgia ratepayers rather than the utilities.

The substantial costs associated with the Vogtle project are acknowledged in Georgia Environmental Protection Division's (EPD) September 16, 2014 comments to the EPA in which they state that they "strongly disagree with EPA's assertion that the capital costs and incremental costs associated with CO2 emissions reductions as a result of Vogtle units 3 and 4 are zero. … The new units are not an inexpensive opportunity to reduce carbon emissions from existing fossil fuel units but are in fact quite costly."[126]

ii) V.C. Summer Units 2 and 3 – South Carolina

SCANA's subsidiary SCE&G has also demonstrated cost overruns and scheduling delays in the construction of two new AP1000 reactors at the V.C. Summer nuclear plant. Original estimates for SCE&G's share of the project were $6.3 billion, for a total project cost of approximately $11.45 billion.[127] In October 2014, updated information from the Consortium building the reactors revealed that SCE&G's portion of the project has increased by $660 million, subject to escalation, bringing the full recent estimated cost overrun to over $1.2 billion.[128] SCANA's subsidiary, SCE&G, is majority owner with 55% of the project and Santee Cooper owns 45%.[129]

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[122] Southern Alliance for Clean Energy, Taxpayers in the dark and at risk from Vogtle nuclear loan guarantees, July 16, 2014. Available at http://blog.cleanenergy.org/2014/07/16/taxpayers-in-the-dark-and-at-risk-from-vogtle-nuclear-loan-guarantees/

[123] See SB31, The Georgia Nuclear Financing Act, Effective April 21, 2009. Available at http://www.legis.ga.gov/legislation/en-US/display/20092010/SB/31

[124] Georgia Power Company, Docket No. 29849, GPSC Hearing Request from Eleventh VCM Hearing, Response to Staff's Eleventh VCM Hearing Request No. 1-1, November 14, 2014. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=155798

[125] Calculate the cost of the NCCR rider on a Georgia Power customer's monthly bills by using the Georgia Power Bill Calculator from the Georgia Public Service Commission, available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=155798

[126] Georgia Environmental Protection Division (EPD), Comments to EPA re: Docket ID No. EPA-HQ-OAR-2013-0602, Comment Topic: Removal of Under-Construction Nuclear from Emissions Performance Goal Computation, September 16, 2014. Available at http://www.georgiaair.org/airpermit/downloads/planningsupport/regdev/ghg/gaepd_ucnuclear_comments09162014.pdf

[127] South Carolina Public Service Commission, Docket No. 2008-196-E, Order No. 2009-104(A), March 2, 2009, p. 45. Available at http://www.scana.com/NR/rdonlyres/B4E46714-6C85-4A19-82D6-E307F15D3976/0/CommissionOrderNo2009104A.pdf

[128] SCANA press release, Preliminary New Nuclear Construction Cost Information from the Consortium, October 2, 2014. Available at http://www.scana.com/NR/rdonlyres/B512CD78-230B-4E84-93F3-0B48D52F0765/0/10022014PreliminaryNewNuclearConstructionCostInformationfromtheConsortium.pdf (costs in 2007 dollars).

[129] In January 2014, SCE&G bought 5% of Santee Cooper's ownership, which will fall to 40% over the next few years. Santee Cooper news release, SCE&G to acquire increased share of nuclear units from Santee

Similar to the Vogtle project, substantial expenditures remain and the full cost of completion is considered unknown given continued schedule delays. SCE&G's quarterly report from September 2014 to the South Carolina Office of Regulatory Staff states:[130]

> *"As shown on Appendix 2, line 39, the cumulative amount projected to be spent on the project as of December 31, 2014, is approximately $3.020 billion. As shown on Appendix 2, line 18, the Cumulative Project Cash Flow target approved by the Commission for year-end 2014 adjusted for current escalation and WEC/CB&I billing differences is approximately $3.819 billion. As a result, the cumulative cash flow at year-end 2014 is projected to be approximately $799 million less than the target."*

In early August, the utility announced another delay of approximately 12 months; the project is thus delayed by at least 30 months.[131] Like the new Vogtle reactors, the original estimates for V.C. Summer's Unit 2 reactor was April 1, 2016 and one year later for Unit 3. According to a SCANA filing with the Securities and Exchange Commission:

> *"…in August 2014 SCE&G received preliminary information in which the Consortium has indicated that the substantial completion[132] of Unit 2 is expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later."[133]*

SCE&G customers are paying for financing charges for the project in advance under the Baseload Review Act (BLRA) passed in 2007. Under that state law, an annual rate hike for the nuclear project shifts much of the risk from the company and shareholders to the ratepayers. The seventh nuclear rate hike for the project was approved by the South Carolina Public Service Commission on September 29, 2014[134] and a rate increase averaging about 2.8% for all customers went into effect on October 30, 2014. Through October 2014, customers have faced an average 2.3% annual increase for the nuclear project since it was approved in February 2009 and approximately 13% of their monthly bill is now for the nuclear costs.[135]

Cooper, January 27, 2014. Available at https://www.santeecooper.com/about-santee-cooper/news-releases/news-items/sceg-to-acquire-increased-share-of-nuclear-units-from-santee-cooper.aspx

[130] SCE&G, Quarterly Report to the South Carolina Office of Regulatory Staff Pursuant to Public Service Commission Order No. 2009-104(A), Quarter Ending September 30, 2014. November 12, 2014, p. 21. Available at http://dms.psc.sc.gov/pdf/matters/6D909E0C-155D-141F-23A7643735CCF607.pdf

[131] SRS Watch, SCE&G Reveals Significant Delays and Cost Increases for Nuclear Reactor Construction Project; Additional Schedule Delay of 12-18 Months with Unknown Cost Increases to Rate Payers, August 12, 2014. Available at http://www.srswatch.org/uploads/2/7/5/8/27584045/srs_watch_on_vc_summer_delays_august_12_2014.pdf

[132] Note: "substantial completion" as stated above does not mean commercial operation. SCANA's Form 10-Q filing with the SEC also indicates additional delays are possible and that a "revised schedule and cost estimate will be finalized sometime in 2015."

[133] SCANA filing with the Securities & Exchange Commission, Form 10-Q quarterly filing for period ending September 30, 2014. Available at http://www.sec.gov/Archives/edgar/data/91882/000075473714000041/a2014930-10q.htm

[134] S.C. Public Service Commission, Docket 2014-187-E, Order Number 2014-785, Application of South Carolina Electric & Gas Company for Approval to Revise Rates under the Base Load Review Act, September 30, 2014. Available at http://dms.psc.sc.gov/pdf/orders/CFCB8DB4-155D-141F-2337B742E1B70B8E.pdf

[135] South Carolina Office of Regulatory Staff, Report on SCE&G's Annual Request for Revised Rates-Part A, August 6, 2014, page 3. Available at http://www.regulatorystaff.sc.gov/Documents/News%20Archives/Final%20Rev.Rates%20Rprt-Part1.pdf

iii) Watts Bar Unit 2 - Tennessee

TVA's efforts to complete a second reactor at their Watts Bar nuclear plant in Spring City, Tennessee represents a very unique situation in terms of under construction nuclear generation and illustrates the troubled history of the nuclear energy industry. Watts Bar 2 has been under construction since 1973 – just three years after the EPA was created and the Clean Air Act was enacted – and well before any regulatory efforts to reduce carbon emissions.[136] Construction stopped in the 1980s due to fleet-wide safety and management concerns at TVA. Construction did not resume until 2007 with operation originally expected in 2012. However, operation has been further delayed until December 2015 and may be delayed even further.[137] Unlike the Vogtle and V.C. Summer reactors under construction, Watts Bar 2 does not have an Operating License (OL) from the NRC.

In addition to experiencing an extremely extended construction and licensing schedule, Watts Bar 2 has encountered cost overruns. In 2012, when TVA announced additional scheduling delays, TVA determined that it would require additional funding of $1.5 to $2 billion, putting the estimate for total cost of completion in the range of $4 to $4.5 billion.[138] The post-2007 cost is in addition to the nearly $2 billion in original construction costs before TVA first halted the project in the mid-1980s.[139] Given this reactor's history and the hurdles that remain, it is reasonable to be concerned about further cost overruns.

One reason for the schedule delays and cost overruns is the need to address safety concerns exposed after the devastating nuclear accident at the Fukushima Dai-ichi nuclear plant in March 2011. A full response for Watts Bar 2 has yet to be resolved.[140] The NRC's Fukushima Near-Term Task Force report included recommendation 2.1, which is in the set of "near-term actions," that advises the NRC to:

> Order licensees to reevaluate the seismic and flooding hazards at their sites against current NRC requirements and guidance, and, if necessary, update the design basis and SSCs [structures, systems and components] important to safety to protect against the updated hazards.[141]

The Task Force also recommended that these issues be resolved for Watts Bar 2 in the course of the operating license (OL) review:

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[136] TVA, Timeline of Watts Bar Nuclear Plant. Available at http://www.tva.gov/news/releases/aprjun12/0426_board_meeting/Timeline_Watts_Bar.pdf

[137] TVA, President's Report, April 26, 2012, slide 27. Available at http://www.tva.com/abouttva/board/pdf/Apr_26_2012_board.pdf

[138] TVA Press Release, "*TVA Releases Cost, Schedule Estimates for Watts Bar Nuclear Unit 2*," April 5, 2012. Available at http://www.tva.com/news/releases/aprjun12/watts_bar.html

[139] Matt Wald, New York Times, *In Tennessee, Time Comes for a Nuclear Plant Four Decades in the Making,* October 19, 2014. Available at http://www.nytimes.com/2014/10/20/us/in-tennessee-time-comes-for-a-nuclear-plant-four-decades-in-the-making.html?_r=0

[140] Diane Curran letter on behalf of Southern Alliance for Clean Energy to NRC Chair Allison Macfarlane re: Watts Bar 2 Operating License Proceeding, June 23, 2014. Available at http://www.nirs.org/reactorwatch/licensing/sacecurranletterwb262314.pdf

[141] U.S Nuclear Regulatory Commission (NRC), Recommendations for Enhancing Reactor Safety in the 21st Century: the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident, July 12, 2011, pp. 30, 74. Available at http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard/ref-library.html

> For the two plants with reactivated construction permits (Watts Bar Unit 2 and Bellefonte Unit 1), the Task Force recommends that those operating license reviews and the licensing itself include all of the near-term actions and any of the recommended rule changes that have been completed at the time of licensing. Any additional rule changes would be imposed on the plants in the same manner as for other operating reactors.[142]

Responsible safety regulation by the NRC could prevent compliance with the CPP if nuclear energy remains an eligible compliance measure. At no point should a short-term Clean Air Act compliance requirement justify relaxed nuclear safety standards, but neither should EPA permit compliance plans that unreasonably presume that nuclear plant construction will proceed on schedule, at projected costs, and without delays due to responsible safety regulation.

d) Risks of a perverse incentive to perpetuate or revive operation of nuclear reactors

EPA requested comment on whether to include an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation in the state goals.[143] Increasing the generation capacity at existing nuclear plants, also known as "uprates," that occur after 2012 should not qualify as "new nuclear generation." Uprates are not a new, innovative technology and are fairly commonplace in the industry.

By including uprates in the CPP, EPA may cause States to consider restarting cancelled and uneconomic nuclear energy projects as a compliance method. For example, Duke Energy Florida's now-closed Crystal River Unit 3 reactor was shut down in September 2009 in order to perform necessary upgrades to allow for an uprate of the plant. Duke ultimately decided that the project was so severely botched that it could not be salvaged. Consequently, Duke decided to close the reactor in February 2013.[144] If uprates are included as a compliance tool, the State of Florida might consider resurrecting this failed project, assuming that some amount of MWs could be available for compliance (original reactor was 860 MWe with an additional 130MWe expected from the now-failed uprate).[145] Expanding the jurisdiction of the Clean Air Act to incentivize nuclear energy projects could put pressure on the NRC to relax safety standards. EPA should carefully scrutinize the consequences of its decision to ensure that it does not unintentionally contest the NRC's regulatory authority.

e) Additional non-air quality impacts from nuclear energy

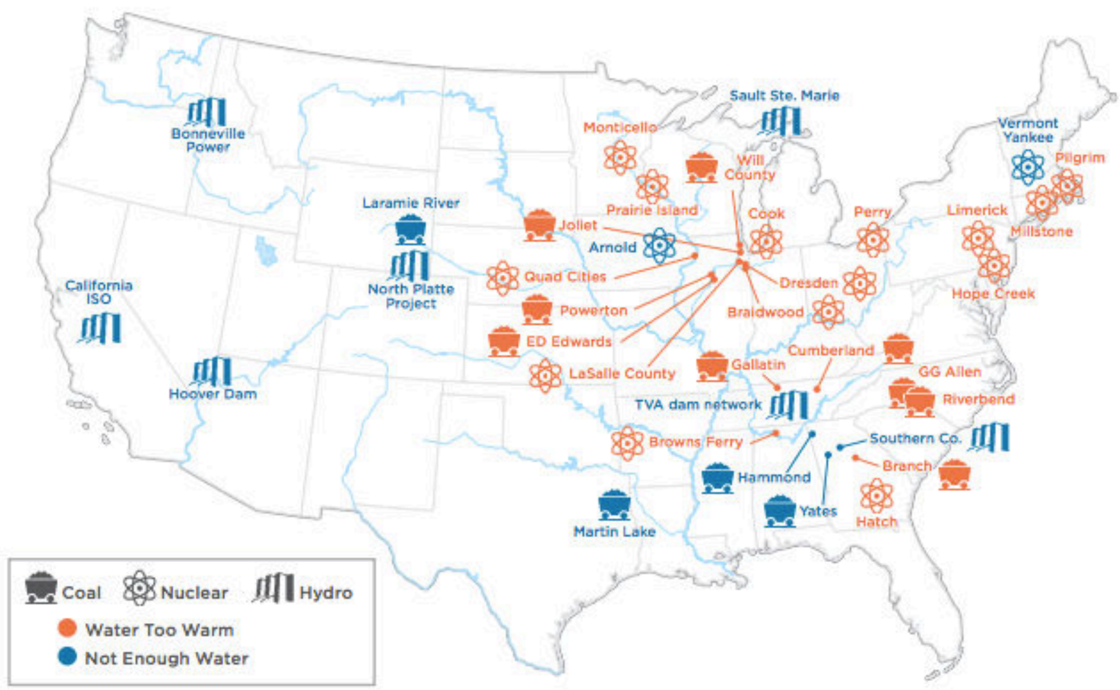
The proposed rule does not adequately address the extensive non-air quality impacts from nuclear energy generation. Under the statute, EPA must fully evaluate the non-air quality impacts before issuing the final rule. In some cases, these impacts are nearly unsolvable issues (long-term management and storage of spent nuclear fuel). The negative public health

[142] U.S Nuclear Regulatory Commission (NRC), Recommendations for Enhancing Reactor Safety in the 21st Century: the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident, July 12, 2011, p. 72. Available at http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard/ref-library.html
[143] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg. 34871. (June 18, 2014).
[144] Before closure of Crystal River Unit 3, approximately $1.3 billion was spent and Duke customers are on the hook for years to come.
[145] American Nuclear Society, Nuclear News, "*Duke ends repair effort, closes Unit 3*," March 2013. Available at http://www.ans.org/pubs/magazines/download/a_865

and safety and environmental impacts of nuclear energy generation are further discussed in Attachment B. But as part of its environmental assessment, EPA should find that the additional environmental risks associated with nuclear generation are too great, and that they should not be allowed as compliance measures.

The water-intensive nature of nuclear energy during normal conditions, and the lack of resiliency during drought conditions contrasts with energy efficiency and renewables, including wind and solar.[146] Nuclear plants in the Southeast and across the country have significant vulnerability to impacts of climate change, including drought, severe weather events and changes to needed water resources in terms of both quality and supply, among others, as demonstrated in Figure 5 below.[147]

Figure 5. Power Plants That Have Shut Down or Reduced Output Because of Water Problems, 2006–2013



When water used to condense steam at power plants is too hot or supplies shrink, the plants run into trouble. Operators have had to shut down or curtail production at numerous power plants because of water-related risks in recent years.

SOURCE: ADAPTED AND UPDATED FROM ROGERS ET AL. 2013.

TVA's Browns Ferry nuclear plant in Alabama, demonstrated serious vulnerabilities during successive years of drought and hot summers, which impacted the Tennessee River and resulted in costs to TVA's ratepayers. In 2010, the reduction in power output cost ratepayers more than $50 million in higher electricity bills.[148] These numerous power reductions over

[146] Union of Concerned Scientists, "*Power Failure: How Climate Change Puts Our Electricity at Risk -- and What We Can Do*," April 2014. Available at http://www.ucsusa.org/assets/documents/Power-Failure-How-Climate-Change-Puts-Our-Electricity-at-Risk-and-What-We-Can-Do.pdf

[147] Union of Concerned Scientists, "*Power Failure: How Climate Change Puts Our Electricity at Risk -- and What We Can Do*," April 2014, Figure 4, p. 7. Available at http://www.ucsusa.org/assets/documents/Power-Failure-How-Climate-Change-Puts-Our-Electricity-at-Risk-and-What-We-Can-Do.pdf

[148] Averyt, K., J. Fisher, A. Huber-Lee, A. Lewis, J. Macknick, N. Madden, J. Rogers, and S. Tellinghuisen. 2011. *Freshwater use by U.S. power plants: Electricity's thirst for a precious resource*. A report of the Energy and Water in a Warming World Initiative. Cambridge, MA: Union of Concerned Scientists. November. pp. 31-

several years eventually led TVA to spend hundreds of millions of dollars to expand the cooling system. Since the map referenced in Figure 5 above was compiled, the reliability of FPL's Turkey Point nuclear plant near Miami was compromised given algae impacts on the plant's ultimate heat sink temperature limit, resulting in reduced energy generation.[149]

f) Alternative consideration of nuclear generation in the CPP

If EPA does not fully agree with our recommendations, and finds that nuclear generation can be a practically enforceable measure in state compliance plans, we recommend that EPA establish at least three specific requirements for states that choose to include nuclear generation in their state compliance plans. First, EPA should require states to identify the responsible party when action (or inaction) by the NRC results in a failure to reduce emissions as planned. Second, EPA should require the state compliance plan to identify how that responsible party will implement timely emission reductions to compensate for any failure to reduce emissions as originally described in the plan. EPA may also wish to set a maximum percentage of the compliance plan (e.g., three percent as discussed in Section 4(a)) that may be at risk to a single project failure as part of this requirement. Third, for purposes of determining the impact of these plants on the state's adjusted emission rate, EPA should treat under-construction nuclear in the same fashion as it treats under-construction natural gas combined cycle (NGCC) plants as laid out in the draft rule.[150]

EPA assumes that any under construction NGCC plants will run at 55% capacity. Accordingly, EPA designated the generation associated with the 55% capacity factor as unavailable for redispatch as a carbon emission reduction tool.[151] EPA made this designation based on the correct assumption that this NGCC generation is intended to meet "other system needs presumed to have motivated the construction" of these NGCCs.[152] Since these NGCC units will be covered under the state emission rate goal, the emissions from this 55% generation is added to the "other" category and averaged into the state goal calculation.[153] EPA does allow for some emission reductions from the under-construction NGCC units, however, by assuming that these units will eventually ramp up to 70% capacity. Thus this extra 15% NGCC capacity is assumed to displace coal generation and count towards a state's compliance.[154]

Following this same logic, EPA should then treat under construction nuclear like under construction NGCC, assigning a percentage of under construction nuclear generation capacity to the "other" category and recognizing that this capacity was built to serve "other system needs." Likewise, EPA should credit a certain percentage of under construction nuclear generation capacity as displacing coal generation and allow the states with these under construction nuclear reactors to include these in their compliance plans.

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32. Available at http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/freshwater-use-by-us-power-plants.html#.VGkEw1fF-4o

[149] U.S. Nuclear Regulatory Commission, *Event Notification Report for July 28, 2014, Event No. 50287*. Available at http://www.nrc.gov/reading-rm/doc-collections/event-status/event/2014/20140728en.html and Jenny Staletovich, Miami Herald, *Feds OK hotter water to operate Turkey Point nuclear reactors*, August 6, 2014. Available at http://www.miamiherald.com/2014/08/05/4273673/feds-ok-hotter-water-to-operate.html

[150] Goal Computation Technical Support Document, US EPA, June 2014 at 12, which defines "under construction NGCC capacity" as anything that came online in 2013 or that was under construction, site prep, or testing by January 8, 2014.

[151] *Id.*

[152] *Id.*

[153] *Id.*

[154] Goal Computation Technical Support Document, US EPA, June 2014 at 12 -13.

5. Conclusion

In order to strengthen carbon emission reduction goals and spur additional investment in clean energy resources through the finalized CPP, we summarize our recommendations for the various energy resources below:

Renewable Energy

- Update methodologies and associated assumptions used in developing the Proposed and Alternative renewable energy approaches, which currently severely underestimate U.S. renewable energy potential.
- Incorporate SACE technical analysis demonstrating that renewable generation could be incorporated in the Southeast without compromising the economic and reliability requirements of the utility industry.
- Update cost and performance inputs for wind and solar in particular, replacing the inputs in EPA's draft CPP that are materially inaccurate with current industry experience.
- Adopt an approach to renewable energy similar to the Union of Concerned Scientists' "Demonstrated Growth Approach," which is a more realistic renewable energy option for the country and consistent with wind and solar market industry trends already occurring in the Southeastern region.[155]

Energy Efficiency

- Finalize an annual incremental efficiency rate of 0.25 percent per year, ramping up to two percent annually.
- Designate all energy efficiency as eligible for state compliance plans, including building energy codes[156] and appliance standards, combined heat and power,[157] and behavioral programs.
- Do not limit energy efficiency resources available to states for use in compliance plans because the savings are difficult to quantify.
- Regarding CSE calculations EPA should:
    - (1) update its cost estimates based on the 2014 ACEEE report, resulting in a 2017 first year net cost of $230 per MWh and a 2017 levelized cost of 2.8 cents per kWh[158];
    - (2) eliminate cost escalation for years when incremental energy savings are less than 2.5% and;
    - (3) utilize the 11-year measure life in the 2014 ACEEE report.
- Provide guidance on EM&V methodologies.

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[155] In the Southeast, the UCS Approach could result in 14% of electricity sales being met with renewables by 2030, which is double the renewable energy generation target produced under EPA's Proposed Approach.
[156] If we were to capture the potential for additional policies, such as the adoption and enforcement of state or local building energy codes, to contribute additional reductions in electricity demand beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5%. FR 34872
[157] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule 40 Fed. Reg 34924 (June 2, 2014).
[158] Maggie Molina, Am. Council for an Energy-Efficient Economy, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (Mar. 2014), *available at* http://aceee.org/research-report/u1402

- Provide a net-to-gross ration so that states may convert net savings goals to a gross savings goal.
- States in which electricity savings occur should get full credit for the energy savings in that state.

Nuclear Energy

- Remove nuclear energy from the CPP scheme, as it does not fit the requirement for BSER.
- Accurately reflect true costs of under construction nuclear, given the common situation of cost increases and scheduling delays experienced by all five under construction nuclear reactors.
- Include non-air quality impacts in analysis of impacts of nuclear energy within the CPP.

We appreciate this opportunity to comment on EPA's draft CPP and offer suggestions on how to make it a more effective, equitable and cost-effective carbon emission reduction tool. Through the arguments and data laid out above, we highlighted the risks and costs associated with including nuclear energy in the CPP scheme and have demonstrated how our Southeastern states can meet EPA's final carbon reduction goals with renewable energy and energy efficiency resources without compromising electric grid reliability and significantly increasing costs to ratepayers.

Respectfully submitted,

The Southern Alliance for Clean Energy

Attachment A

Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast

Summary

Utilities in the Southeast are beginning to consider deployment of variable renewable energy resources on their systems, with some proposals suggesting that 10-20% of annual electricity demand might be sourced from wind and solar in the next decade. Elsewhere in the country, technical experts have concluded that variable renewable energy resources can meet at least 50% of electric system demand using currently available technology and system management capabilities,, provided that utilities make "investment in additional distribution and transmission system infrastructure as well as changes in electric system operations, markets, and planning to achieve reliability."[1] Across much of the United States, these questions are systematically addressed through the planning processes of regional transmission operators (RTOs), independent system operators (ISOs) and super-regional planning organizations such as the Western Electricity Coordinating Council.

However, in the Southeast, several large vertically-integrated utilities conduct their own resource adequacy, reliability and operational planning with minimal market exposure. Due to historically limited solar and wind development, vertically-integrated utilities in the Southeast have not provided analyses of renewable energy that are as comprehensive or similarly robust as those in RTO or ISO regions. While few of their planning studies have thoroughly examined renewable energy resources, these studies do often raise questions regarding renewable resource adequacy, reliability and flexibility.

This study summarizes the information available from these utilities, and answers the following key questions with analysis that could be used in a variety of energy planning activities.

1. **How much conventional capacity can be replaced by:**

    - **Solar photovoltaic (PV) power resources?** For every 100 megawatts (MW) of solar power resources, about 50-70 MW of conventional generation capacity can be avoided. The exact value depends on the location and technology used.

    - **Southeastern wind power resources?** For every 100 MW of wind resources generated in the Southeast, the limited available data suggest 10-15 MW of conventional generation capacity can be avoided. Both technology change and the lack of data suggest that these estimates are subject to revision.

    - **Wind power imported via HVDC transmission?** For every 100 MW of wind resources imported into the Southeast via HVDC transmission, about 45-60 MW of conventional generation capacity can be avoided. The exact value depends on the wind characteristics, the business model for the

[1] Linvill, C., Migden-Ostrander, J. and Hogan, M., *Clean Energy Keeps the Lights On*, Regulatory Assistance Project (June 2014).

transmission provider, and the amount of "wheeling" from one utility system to another that is needed.

2. **Will these *capacity values* change if renewable energy penetration levels increase?** Yes, if the Southeast deploys a mix of solar and wind resources to meet 10-20% of annual electricity demand, these values will change. For solar, the values would drop to 25-40 MW; for regional wind, the values would increase slightly; for HVDC wind imports, the values would drop to 20-40 MW per 100 MW of conventional generation.

3. **Will renewable energy cause utility system *reliability* to decrease at:**

   - **Current or projected near-term penetration levels?** No, while renewable energy resources are variable, they perform very well during high demand periods when utility systems need to use most of their generation resources. On average, regional solar and imported wind resources should generate at 50-60% dependable capacity factors during these hours in the Southeast. At current and near-term levels of renewable energy use, long-term modeling analysis indicates no increased reliability risks at the system level – even during hours in which renewable energy production might be low.

   - **Significantly higher levels of renewable energy development?** No, even if renewable energy is increased to meet 10-20% of annual electricity demand, reliability should be relatively unaffected on balance. At these higher levels of renewable energy use, there would be a balance of increased and decreased risks that utilities would need to study and monitor. Hours with increased reliability risks would occur very infrequently, roughly only one hour per year on average. However, that same level of renewable energy generation would actually increase the number of hours in which reliability is ensured by about 80 hours per year.

4. **Could solar power cause some utility systems to effectively shift from a summer to winter peak, thus negating its benefits during a "polar vortex" type event?** Winter peaks in the Southeast are occasionally nearly as high as summer peaks. Nonetheless, even with several gigawatts (GW) of solar energy added to existing utility systems, winter peaks did not become the most challenging reliability condition in any of the utility systems we studied. It is important to study this potential effect in the context of other system resources. Because conventional generation operates more efficiently during winter peaking episodes, a system planned for summer peak will have more conventional capacity available in the winter to compensate. Furthermore, wind power produces very well during winter peaking episodes. In general, an optimized approach to resource, operation and reliability studies should be sufficient to plan for a "polar vortex" type event.

5. **Will conventional generation plants have to ramp up and down rapidly to balance variable renewable generation?** Utility operators will not need to increase the ramping of conventional generation under current and projected near-term renewable energy penetration levels. Up to around 10% of energy supply, utility systems may actually be easier to operate, since solar energy in the Southeast is closely aligned with system peaks. While the transition point depends on the utility system and the resources applied, even at 10-20% of annual electricity demand, the California "duck curve" problem of high ramp rates for conventional generation is unlikely to appear in the Southeast.

These questions have been answered by matching industry-standard data about potential wind and solar generation to the historical generation data supplied by Duke Energy (in the Carolinas), Southern Company (including Alabama, Florida, Georgia and Mississippi subsidiaries), and the Tennessee Valley Authority (serving portions of seven Southeastern states). The methods applied in this analysis utilize industry-standard techniques, enhanced to more carefully examine reliability and capacity value concerns regarding renewable energy development in the Southeast.

1. Dependable (on-peak) Capacity Values of Renewable Energy Resources in the Southeast[2]

In determining whether a utility has adequate resources to meet its forecast system requirements, Southeastern utilities utilize a dependable capacity factor (DCF) for renewable energy resources. (Elsewhere these may be referred to as an on-peak capacity value, a generation capacity credit, or by some other nomenclature.) The DCF may be thought of as a "derating factor" which takes into account not only the output capabilities of a renewable energy resource, but also the usefulness of the resource output in meeting overall electric utility system reliability standards.[3] Under current and projected near-term penetration levels, this analysis demonstrated that a mix of renewable energy resources can be deployed in the Southeast using a DCF of approximately 50%. This means that utility operators would be able to assume that renewable energy resources reliably produce about half of the rated nameplate capacity during hours of peak electric demand.

Each electric resource comes with its own operational constraints and capabilities, which are routinely quantified by utilities. Modern natural gas plants offer rapid start and turndown capabilities. Nuclear power output can typically be varied within a narrow band, but operational and financial considerations make it impractical to vary much with load on an hourly or even daily basis. Large steam plants (fossil and nuclear) require hours to start up, more hours to reach full outputs, and shut downs cover even more hours. Outputs from thermal generation resources are often higher in the winter, reflecting greater operating efficiencies due to cooler water and air temperatures. Each generating unit demonstrates an evolving forced outage rate reflecting its inherent reliability and the need for system redundancy. These and many other factors are properly quantified by utilities within the context of reserve margin and resource planning studies.

In contrast to an evenhanded, data-driven approach, Southeastern utilities have sometimes emphasized the "operational limitations" of renewable energy in a less rigorous or systematic manner. For example, Duke Energy describes solar energy as a resource that:

> …cannot be dispatched to meet changing demand from customers all hours of the day and night, through all types of weather … by way of comparison: Solar energy's equivalent full output is available approximately 20% of the time. Nuclear energy's equivalent full output is available greater than 90% of the time. Natural gas combined cycle's energy is available greater than 90% of the time. As a result, it can take 4 to 5 MW of installed solar generation to produce

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[2] See Attachment A for more detail on this topic.

[3] Styled after definition of ELCC, as described by California Public Utilities Commission, Energy Division, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources*, Staff Proposal, Resource Adequacy Proceeding R.11-10-023 (January 16, 2014), p. 1.

> the same amount of energy that is available from a single MW of natural gas or nuclear generation.[4]

Elsewhere in the same document, Duke Energy attributes a 45% DCF to solar energy, but its operational summary makes clear that the corporate view of solar is that of an impaired, barely relevant resource. While the *energy* produced by solar and wind resources is variable and not represented by its peak output, modern forecasting techniques and the geographic dispersal of these resources provide utilities with the opportunity to plan for and control gradual or even sudden changes in solar and wind power production.[5]

Southeastern utilities appear to have adopted capacity factor-based approximation methods for measuring DCFs.[6] A relatively simple approach that provides "basic insight into the coincidence of [renewable] generation and load," it is not frequently used in major studies of renewable generation due to the "widespread acceptance and use of more sophisticated methods."[7] The preferred metric for measuring the DCF is the effective load carrying capability (ELCC) method. However, the ELCC method requires, among other data, a "complete inventory of conventional generation units' capacity, forced outage rates and maintenance schedules."[8] With Southeastern utilities in significant flux, considering a high number of ongoing plant retirements and new generation in process, it is impractical for a non-utility planning study to obtain a useful forecast with a "complete inventory" of these data.

In a study that reviewed the methods used by Southeastern utilities for measuring DCFs, it was noted that they are less useful and potentially inaccurate relative to the ELCC because they do not "capture the short term or annual variability" of variable renewable energy resources, or their correlation with demand throughout the year.[9] In order to address this shortcoming without engaging in an impractical forecasting effort, a new variant of the capacity factor-based approximation method, the System Peak Hours (SPH) method, is utilized in this analysis and described in greater detail in Appendix A. The SPH method is effective at capturing both the short-term (hourly) correlation with demand, as well as the annual variability of renewable energy resources. The SPH method improves on other capacity factor-based approximation methods by using a matched, multi-year set of renewable energy generation and utility system demand data.

For example, TVA's current method for establishing the DCF of solar power resources is the average summer capacity factor during the 5 – 6 pm CDT (also referred to as CPT or central planning time) hour.[10] An evaluation of TVA's system load data shows that this hour has been one of the top 20 system

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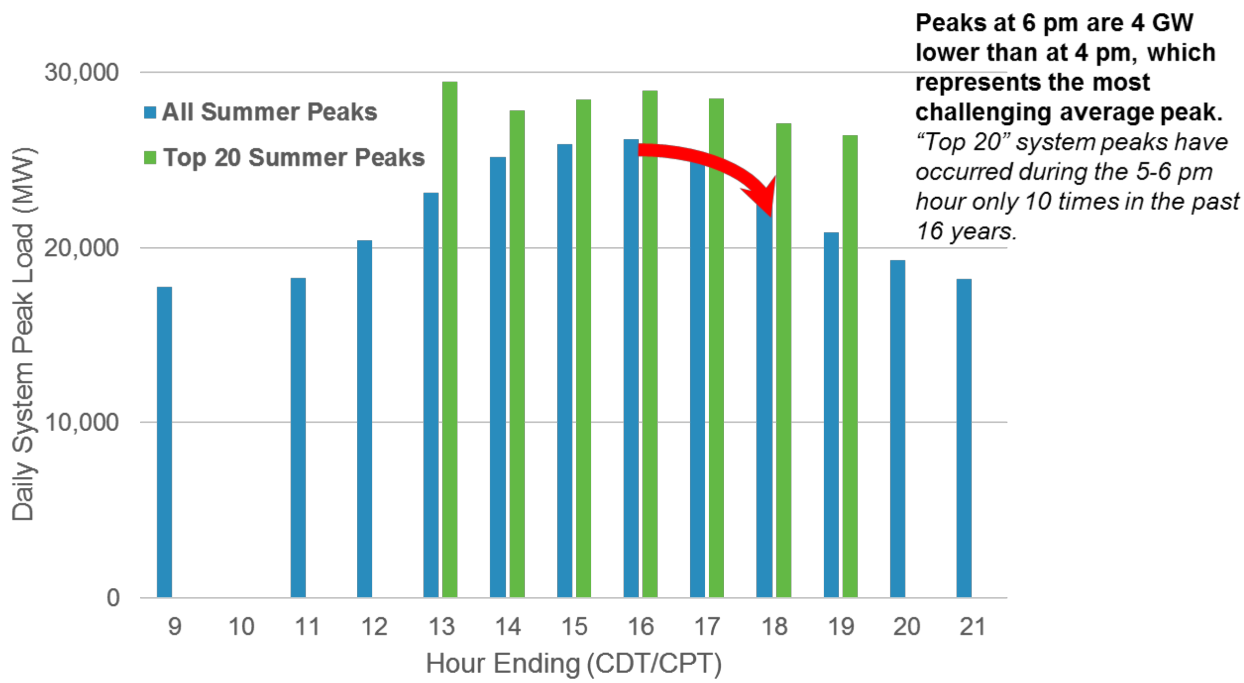
[4] Duke Energy Carolinas, *Integrated Resource Plan (Annual Report)* (September 1, 2014), p. 6.
[5] Ela, E. et al., *Active Power Controls from Wind Power: Bridging the Gaps*, National Renewable Energy Laboratory, University of Colorado, and Electric Power Research Institute, NREL Technical Report NREL/TP-5D00-60574 (January 2014).
[6] Not all Southeastern utilities that measure DCFs have publicly described their methods.
[7] Denholm, P. et al., *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*, National Renewable Energy Laboratory, NREL Technical Report NREL/TP-6A20-62447 (September 2014).
[8] Keane, A. et al., "Capacity Value of Wind Power," *IEEE Transactions on Power Systems* (v. 26, no. 2), Task Force on the Capacity Value of Wind Power, IEEE Power and Energy Society (September 2010), p. 3.
[9] Keane (2010), p. 4.
[10] Tennessee Valley Authority, "2015 Integrated Resource Plan: IRPWG Meeting Session 7 – Day 2," (May 30, 2014) Slide 27.

peaks only 10 times over a 16-year period (about 3% of such peaks). Furthermore, as illustrated in Figure 1, TVA system peaks at 6 pm are 4 GW lower than at 4 pm. In other words, daily peaks occurring at 4 pm are usually more than 13% higher than daily peaks occurring at 6 pm. Thus, the hour that TVA has chosen to use to evaluate solar system performance is neither representative of typical system peaks nor is it representative of periods in which system capacity needs are particularly stretched. The SPH method is designed to focus on hours that are representative of periods in which system capacity needs are stretched, and to exclude hours in which system capacity needs are easily met by the utility's power resources.

Figure 1: TVA System Summer Peaks (1998-2013)



Because the SPH method and the measurement methods used by Southeastern utilities all use capacity factor averaging during peak periods, it is not surprising that a comparison of those measurements shows that they are sometimes in rough agreement. TVA's method for wind resources is different from that used for solar. Briefly summarized, TVA averages the capacity factor for the peak hour on each of the 20 peak days during the summer season.[11] Although not as well documented, Duke Energy (in the Carolinas) and Southern Company (whose values are not publicly disclosed) appear to use a peak-period capacity factor averaging method that utilizes a block of summer hours.[12]

Based on the analysis conducted for this report using the SPH method, as illustrated in Figure 2, the following results were demonstrated in the Southeast:

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[11] Tennessee Valley Authority, "2015 Integrated Resource Plan: IRPWG Meeting Session 7 – Day 2," (May 30, 2014) Slide 25.

[12] Duke Energy Carolinas, *Integrated Resource Plan* (September 2014); and Duke Energy Progress, *Integrated Resource Plan* (September 2014). Georgia Power Company, *Advanced Solar Initiative and ASI-Prime Request for Proposals for Solar Photovoltaic Generation,* Attachment G (March 10, 2014).

- For every 100 MW of solar power resources, about 50-70 MW of conventional generation capacity can be avoided. The exact value depends on the location and technology used. TVA's values are in close agreement with these, Duke's 45 MW value appears somewhat low, and Southern Company does not disclose its DCF value.
- For every 100 MW of wind resources generated in the Southeast, the limited available data suggest 10-15 MW of conventional generation capacity can be avoided. Both technology change and the lack of data suggest that these estimates are subject to revision. These values are consistent with (even a bit lower than) the values used by TVA and Duke (again, Southern Company does not disclose its DCF value).
- For every 100 MW of wind resources imported into the Southeast via HVDC transmission,[13] about 45-60 MW of conventional generation capacity can be avoided. The exact value depends on the wind characteristics, the business model for the transmission provider, and the amount of "wheeling" from one utility system to another that is needed. Even though TVA is actively considering the import of these resources, TVA is currently utilizing a much lower value derived from market experience with wind resources from other regions.

Considering projected or likely near-term renewable energy development pathways, a mix of renewable energy in any Southeastern utility territory is likely to have a dependable capacity rating of roughly 50%.

[13] Imports of wind energy via regional AC transmission grids were not studied.

Figure 2: Summer Dependable Capacity Factors Calculated Using System Peak Hours Method, Assuming No Substantial Prior Renewable Energy Development

2. *Impact of Renewable Energy Development on Dependable Capacity Factors*[14]

If the Southeast deploys a mix of solar and wind resources to meet 10-20% of annual electricity demand, the DCFs will decrease. For solar, the values would drop to 25-40 MW; for regional wind, the values would increase slightly; for HVDC wind imports, the values would drop to 20-40 MW per 100 MW of conventional generation.

Few utilities in the Southeast currently account for the general decline in the DCFs of renewable energy resources as grid penetration increases. The DCF decreases as grid penetration increases because the number of hours in which the utility faces significant capacity shortfalls decreases during times when renewable energy is generating. (This shift is also examined in Section 4.) This may not be an important oversight if low grid penetration is assumed, but planning for scenarios with 10-20% of energy supplied by renewable energy generation clearly requires such consideration.

For example, DCFs for utility-scale solar power resources in the three utility service areas today are at very similar levels for both fixed mount systems (49-54% DCFs) and single-axis tracking systems (60-63%). However, as illustrated in Figure 3, at higher levels of deployment, the DCFs diverge somewhat. For Duke Energy, which has the least wind power included in its scenario, the DCF values do not decrease as much as for the other two utilities. (The scenarios, as described in Appendix A, included over 4,000 MW of solar plus varying amounts of wind, but dependable capacity values were only estimated at 2,650 – 3,800 MW, depending on the utility scenario.)

Although there are some differences driven by the distinct characteristics of each utility scenario, the overall finding for solar is that there is a consistent alignment of solar energy production relative to the system load shapes across the Southeast, and the impact of solar development on DCF values decreases in a consistent manner.[15] Another interesting observation is that higher capacity values are generally obtained towards the western portion of the region. This can be seen by noting the slight improvement for solar in Alabama, Florida or Mississippi relative to Georgia, but is also observed within the TVA dataset.

Other sources of potential capacity value sometimes overlooked by utilities are the value of regional coordination, and synergies among different resources. Both of these features are considered in this analysis. Regional coordination benefits are demonstrated by higher capacity values obtained by assuming that much of the solar energy development would occur in utility areas with higher DCFs. As described in Appendix A, utilizing an average of several sites demonstrated better performance than just using any single site.

Furthermore, as illustrated further in Appendix A, the application of wind and solar resource development together in scenarios resulted in a better understanding of how DCFs would likely evolve under foreseeable development scenarios. For example, even though DCFs for wind alone would decrease with its development, in combination with solar development, the DCFs instead increase.

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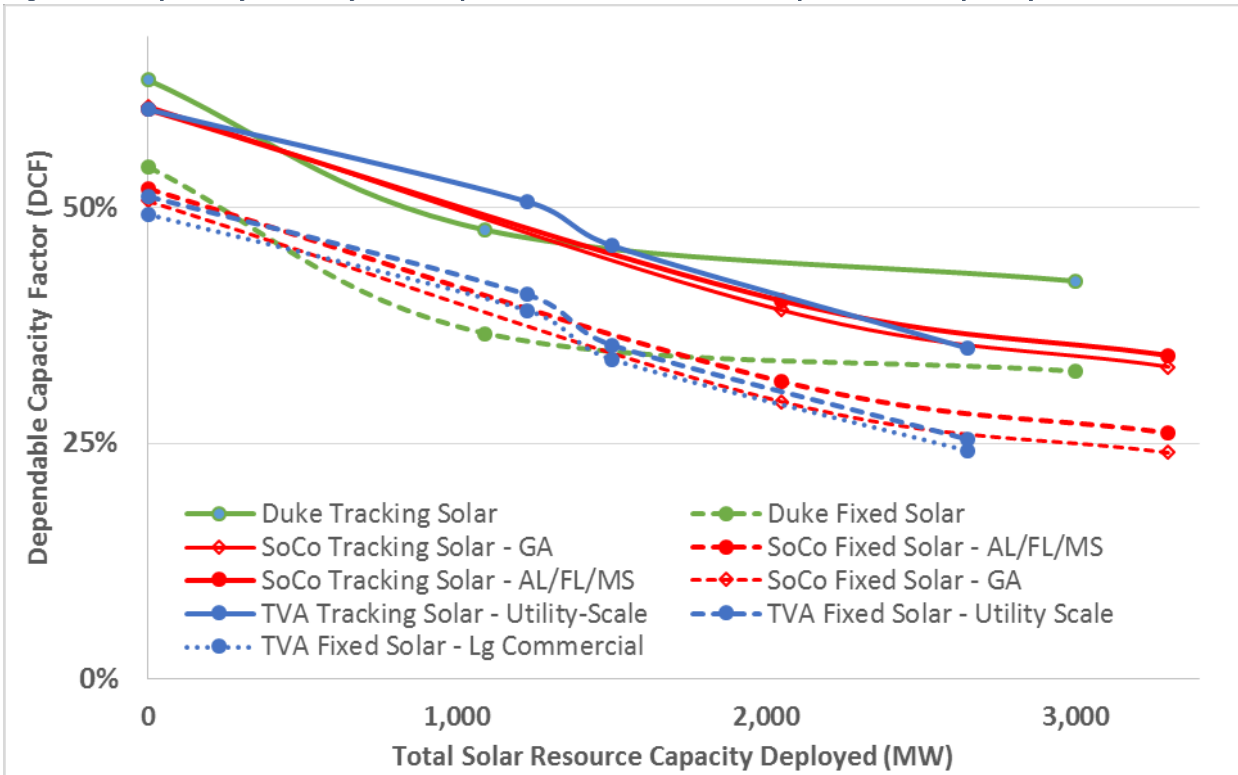
[14] See Appendix A for greater detail on this topic.

[15] Solar DCFs do vary somewhat as wind resources are deployed. The sharp, but small, drop in TVA's DCF values between Tranches 2 and 3 appears to be caused by wind resource deployment.

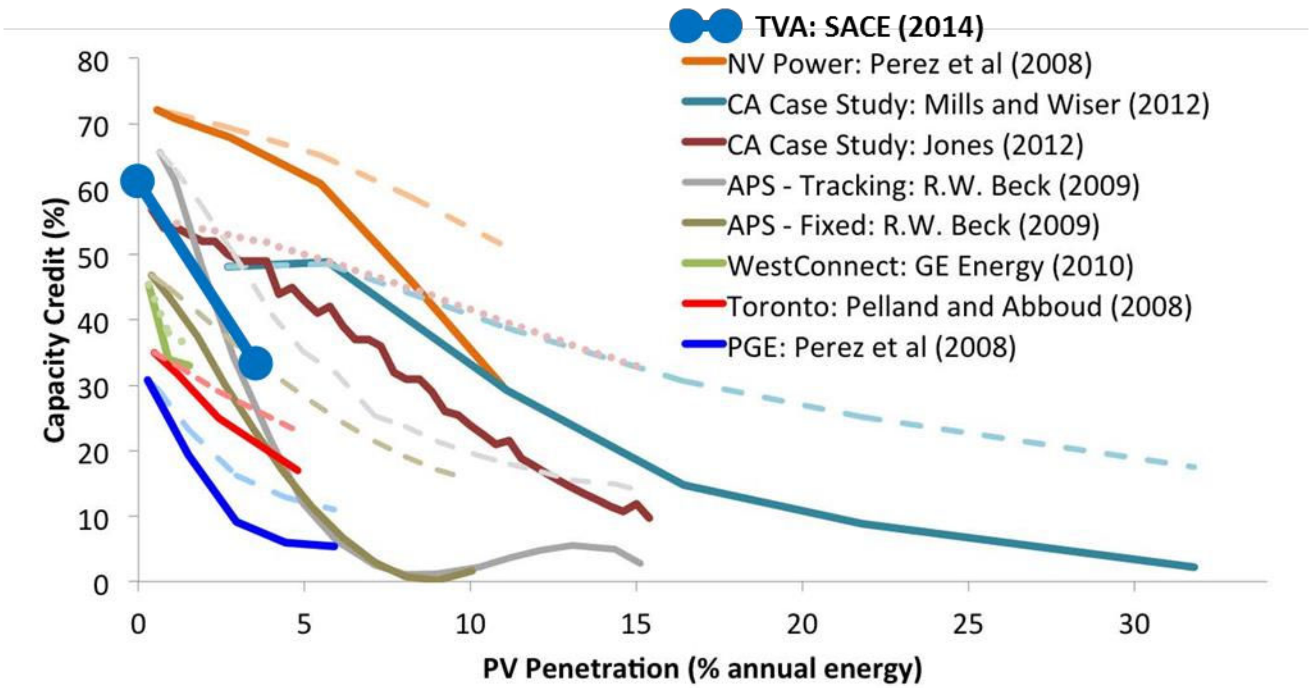
Figure 3: Impact of Scale of Development on Solar Power Dependable Capacity Factors



The trends observed in Figure 3 are consistent with findings for other utilities across the country. For example, TVA's average solar DCF (fixed and solar) is plotted against similar values from other utilities in Figure 4.[16] (DCFs are referred to as "capacity credit" in the figure, and the 3,950 MW of solar energy studied over the 1998-2012 study period represents about 4.4% of TVA system demand at the higher end of the TVA trend in the figure.) These findings also suggest that the Southeast has relatively high DCF values for solar.[17]

[16] Mills, A. and R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes*, Lawrence Berkeley National Laboratory, LBNL-5933E (December 2012).
[17] This advantage was first observed by Richard Perez in the early 1990s. Perez, R., S. Letendre and C. Herig, *PV and Grid Reliability: Availability of PV Power During Capacity Shortfalls*, Proc. ASES Annual Meeting (2001).

Figure 4: TVA Solar Dependable Capacity Factor Contrasted with Other Utilities Summarized by LBNL



3. Impact of Renewable Energy Development on Utility System Reliability[18]

While renewable energy resources are variable, they perform very well during high demand periods when utility systems need to use most of their generation resources. On average, regional solar and imported wind resources should generate at 50-60% capacity factors during these hours. However, the level of renewable energy generation in the Southeast today and planned for the near-term is not large enough to increase system reliability risks – even during hours in which renewable energy production might be low.

Furthermore, even if renewable energy is increased to meet 15% or more of energy requirements, reliability should be relatively unaffected. At these higher levels of renewable energy use, there would be a balance of increased and decreased risks that utilities would need to monitor and manage.

To place the balance of risks in context, it is worth noting that during the vast majority of hours of the year, system demand for a utility is well below available resources. For example, the three utilities studied here would typically have a 25% (or greater) capacity surplus for 98% of the year. During those remaining hours, the utility would manage a very small risk that available generation would not be sufficient to meet demand.

Thus, utility system reliability would change in both directions, there would be reliability risks and benefits associated with renewable energy development. Hours with increased reliability risks would occur very infrequently, roughly one hour per year on average (an adverse effect). However, that same

[18] See Appendix B for greater detail on this topic.

level of renewable energy generation would also improve reliability by reducing the number of "risky" hours by 20-40% (a beneficial effect).

With the data available to this analysis, it is not possible to quantitatively demonstrate whether the benefits outweigh the adverse effect.[19] Nonetheless, it is possible to arrive at some quantitative observations of these competing effects by identifying the results of two key metrics:

- **Higher risk hours**: The number of hours in which renewable energy, in a well-planned system, results in lower hourly capacity reserves.[20]
- **Reliability ensured hours**: The reduction in the number of hours with a significant probability of reliability incidents, defined as capacity reserves of less than 125% of hourly demand.

As illustrated in Figure 5, the ratio of higher risk hours to reliability ensured hours is 1:76 or less, with a clearly positive impact appearing to occur on the Duke Energy system on which no higher risk hours result, even though the scenario studied was heavily weighted towards solar power.

Figure 5: Impact of Renewable Energy Development Scenarios on Reliability

	Higher Risk Hours	Reliability Ensured Hours	Ratio
Duke Energy (North and South Carolina)	0.0 % (0)	0.734 % (558)	0:100
Southern Company	0.007 % (6)	0.549 % (481)	1:80
Tennessee Valley Authority	0.008 % (11)	0.639 % (840)	1:76

Even if the ratio of higher risk hours to reliability ensured hours is very low, it would be reasonable to be concerned that there could be specific hours in which a system that depends on high levels of renewable energy might be at greater reliability risk due to highly unusual circumstances. Utility executives have raised just this concern, citing reliability challenges that occurred during the recent "polar vortex" and speculating about the difficulty of meeting those challenges with high levels of solar penetration.[21] This anecdotal concern is discussed in the following section.

The more general concern that might be raised is that these results just seem implausible. Some readers may be dubious that replacing 3-4 GW of conventional generation with 8 GW of renewable energy (e.g., in the case of TVA) could result in little or no decrease in reliability. This concern can be addressed in two ways.

First, the use of a forecast scenario of renewable energy deployment guides utilities towards an appropriate amount of dispatchable capacity that may be replaced with variable resources. So the 8 GW of nameplate renewable energy capacity studied for the TVA system offsets "only" 4 GW of dispatchable generation capacity. It should be noted that this substantial change would also result in the utility

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[19] The underlying methods of a target reserve margin study involve stochastic evaluation of probabilities. For example, in a random draw of circumstances, the utility may not experience a reliability event during an hour with an effective reserve margin of 10%, but might experience a reliability event during an hour with an effective reserve margin of 20%.

[20] In other words, the number of hours in which the utility might consider taking additional measures to ensure no added risk of a reliability incident.

[21] Mazzocchi, Lee, "The Challenge of Making the Electric Grid Better," EPRI Smart Distribution and Power Quality Conference (July 2014).

changing its dispatchable generation fleet by adjusting the optimal mix of new capacity (e.g., gas peaker versus combined-cycle units). Those changes in the expansion plan would be developed in a resource planning study.

Second, the use of a multi-year dataset ensures that the resulting planning standards incorporate many different actual challenges to reliability. Some hours are more reliable, some hours are less reliable. Implausible examples can be constructed to make any resource plan look risky. Isolating the analysis to a particular "strawman" hour would ignore the improvements in many other hours.

For example, the probability of solar, in-region wind and imported wind power dropping from 8 GW to 0 GW in a single hour is no more likely nor relevant to the planning of the three utility systems analyzed here than the loss of 8 GW of nuclear capacity in a single hour. Any "perfect storm" scenarios a utility might wish to address could be addressed with specific mitigation measures (e.g., modifying a thermal generation unit to be more reliable at cold temperatures). By considering aggressive, but realistic scenarios of renewable energy development in the context of actual system conditions for over a decade, the likelihood that an extreme event has been overlooked has been minimized.

4. Role of Solar Power on Utility Systems During Winter Peak or "Polar Vortex" Type Events

As solar power is developed to scale, the net system peak may shift from primarily summer afternoon hours to include more summer evening and winter morning hours. Since the output of solar systems is relatively small (or zero) during those hours, the contribution of solar power to meeting system peak needs would be diminished. As discussed above, with increasing amounts of solar power deployed on utility systems, the DCFs for solar systems declines. However, some may be concerned that depending on capacity from solar systems might put the utility at greater risk during an extreme winter peak event (e.g., "polar vortex").

In fact, none of the utility systems we studied demonstrate such a problem. The data sets used for this study include three utilities studied over more than a full decade of historical hourly load data, totaling literally hundreds of thousands of hours. As illustrated above in Figure 5, the total number of hours in which the effective reserve margin for these three utilities was worse with renewables than without is only 17 hours, or less than 0.01% of the hours in the analysis period.

One reason that winter peaks are not a problem is that the winter peaking hours in the Southeast tend to be significantly lower than the annual forecast peak. For Southern Company, in fact, the maximum winter load hour within the ten year dataset was only 96% of the forecast annual peak. For Duke Energy and TVA, there were a few winter load hours that exceeded 100% of the forecast annual peak, but the vast majority of winter load hours were 95% of the forecast annual peak or less. In short, Southeastern utility systems almost always have an adequate buffer between winter peaks and the forecast annual peak.

This buffer is reinforced by the more efficient operation of conventional generation during the winter. system planned for summer peak will have more conventional capacity available in the winter to compensate. For thermal generation resources, such as natural gas units or nuclear power, the winter capacity rating is typically somewhat higher, resulting in a summer "shortfall." For renewables, the DCF of solar energy is higher in the summer than in the winter, indicating a summer "shortfall." Thus, the potential for capacity needs to be determined in the winter rather than summer would occur when the winter "shortfall" of renewable energy resources is greater than the summer "shortfall" of thermal generation resources. As illustrated in Figure 6, for two of the three utilities considered it appears unlikely that the levels of renewable energy studied would in and of themselves cause the peak to shift from summer to winter.

Figure 6: Impact of Substantial Renewable Energy Development Scenarios on Seasonal Peak

Dependable Capacity (MW)	Thermal Generation			Renewable Generation Scenario		
	Summer	Winter	Summer "Shortfall"	Summer	Winter	Winter "Shortfall"
Duke Energy (Carolinas)[22]	35,467	37,302	**1,835**	2,246	619	**1,627**
Southern Company[23]	41,522	43,095	**1,573**	3,099	2,312	**787**
Tennessee Valley Authority[24]	40,040	41,157	**1,117**	3,141	1,890	**1,251**

Even though the Duke Energy scenario does not suggest any reliability issues (as summarized in the discussion related to Figure 5), it should be discussed further here because it is an almost all-solar scenario. Due to the lack of hourly generation data stretching back for a decade or more for wind resources available in or near Duke Energy's territory in the Carolinas, the maximum renewable scenario for Duke Energy in this study only includes 500 MW of wind resources, delivered via HVDC transmission and wheeled across the TVA and Southern Company systems for delivery to Duke Energy.[25] So the impact on seasonal peaks for Duke Energy can be viewed as representative of a utility that selects mostly solar power for its resource portfolio as opposed to also including wind power. However, renewable generation below the DCF was demonstrated during a few hours (less than 1 hour per year) in which the winter load was near or above the forecast annual peak. This observation supports the recommendation to balance solar with wind to ensure year-round reliability.

TVA is the only utility in which the summer "shortfall" for thermal generation is smaller than the winter "shortfall" for renewable generation, which indicates a risk for an 8 GW renewable energy generation scenario to cause a shift to a winter peaking situation. However, the thermal generation data for TVA are for 2013 and do not include substantial changes in TVA generation anticipated to be in place over the next several years.

Besides the winter "buffer" discussed above, another reason that solar energy is unlikely to result in greater reliability problems during "polar vortex" type events is that wind power is likely to be substantial during winter peaking episodes. As a result, the combined impact of solar and wind power during the very highest winter peak load periods is consistent with its DCF.

For example, TVA has experienced winter peaking conditions on average 11 hours per year over a 15 year period. In Figure 7, the power generation from an 8,000 MW portfolio of wind and solar is graphed for all 158 winter peaking hours. For hours with winter loads greater than 97% of the forecast annual

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[22] Thermal generation capacity based on 2020 forecast for Duke Energy Carolinas, *Integrated Resource Plan* (September 2014); and Duke Energy Progress, *Integrated Resource Plan* (September 2014).

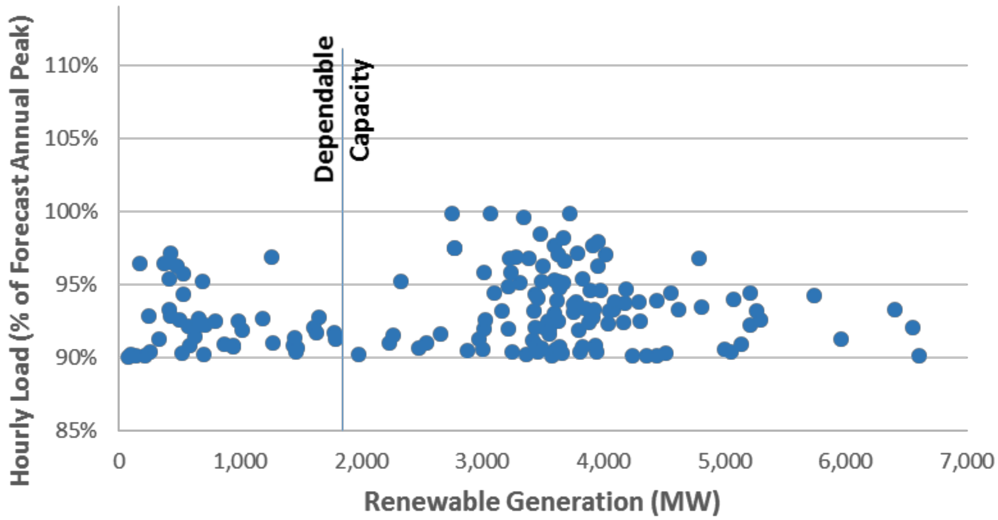
[23] Thermal generation capacity based on 2020 forecast for Southern Company, which is not available in a public document from Southern Company. This forecast was prepared for Southern Alliance for Clean Energy using public data by a consultant working on a confidential project.

[24] Thermal generation capacity based on January and August 2013 data for Tennessee Valley Authority, FERC Form 714 (Part 2, Schedule 2).

[25] Southeast Regional Transmission Planning Process, *2014 Economic Planning Studies: Preliminary Results* (September 2014).

peak, the renewable generation has capacity factors of approximately 40-60%. While wind and solar generation is likely to be very low during some winter peaking hours, since those hours are less than 97% of the forecast annual peak, the impact on reliability turns out to be consistent with conventional system risk standards.

Figure 7: Renewable Generation (8,000 MW Wind and Solar) vs TVA Load During Winter Peak Hours, 1998-2012



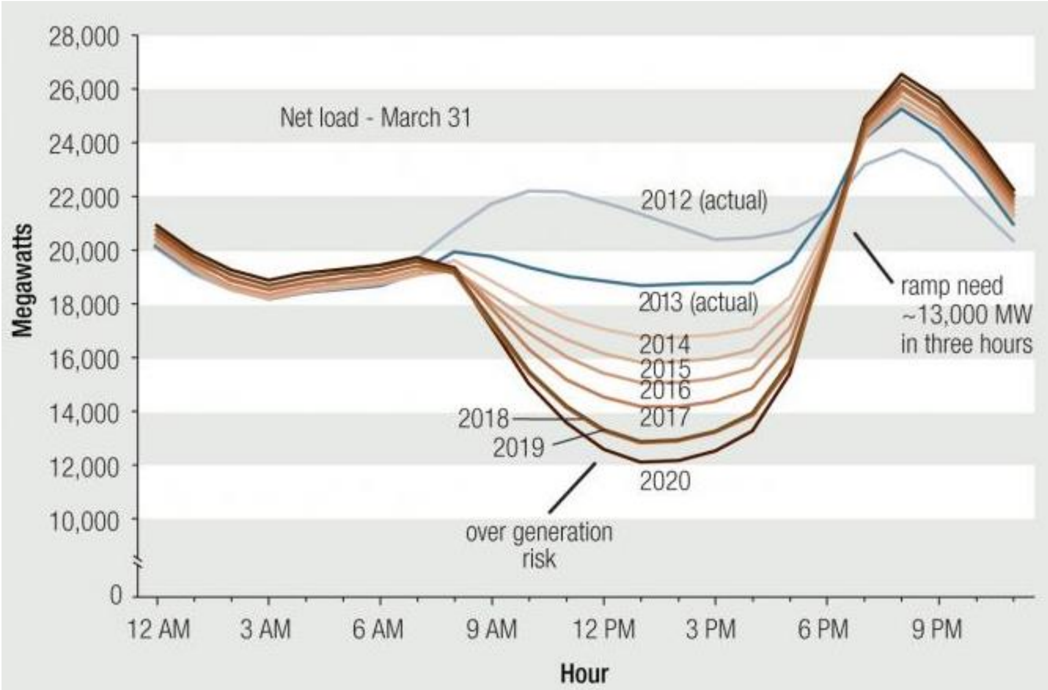
5. Impact of Renewable Energy on the Ramping of Conventional Generation Plants[26]

No discussion about renewable energy and the ability of utilities to adapt to utility resource planning can be complete without a reference to the widely cited California ISO "duck curve."[27] As illustrated in Figure 8, CAISO has forecast that the growing deployment of solar power in its transmission region will lead to episodes with large, rapid ramps during late afternoon hours as solar production rapidly ends. Because it illustrates the potential for renewable generation to drive a ramp rate of over 4 GW per hour in the springtime, the graph has generated widespread concern about the impact of renewables on utility system operations.

[26] See Attachment C for more detail on this topic.

[27] California ISO, *What the Duck Curve Tells Us About Managing a Green Grid´* (2013).

Figure 8: Example of the Widely-Circulated California ISO "Duck Curve"



This graph, and others similar to it, have been circulated by senior utility executives in the Southeast.[28] However, the CA-ISO "duck curve" is not representative of conditions that are likely to occur in the Southeast, even at renewable energy deployment of 10-20% of annual electrcity demand.

In the Southeast, renewable energy generation will not cause any net increase in the ramping of convention generation in the near future. At levels of renewable energy deployment up to at least roughly 20% of annual peak demand, the following observations were made in this analysis:

- While some individual hours might have increased ramps, other hours will have decreased ramps.
- Large, rapid ramps will not become more frequent or severe due to solar power deployment.
- Substantial deployment of wind power will drive some increase in the frequency of ramping events, but will not cause a new class of large ramp rates.
- In general, solar power provided reliable on-peak power that tracks well with system peaks. While its impact does diminish as resource deployment becomes larger, that effect is gradual, predicable and manageable.

To reach these findings, the utility ramp rates should be put into perspective. The vast majority of utility ramp rates, <u>with or without</u> up to the maximum 8 GW of renewable energy analyzed here, remain below 5% of total system capacity. The idea that installing renewable energy with a nameplate capacity as great as 20% of total system capacity will lead to wide swings in operating loads is not supported by the data.

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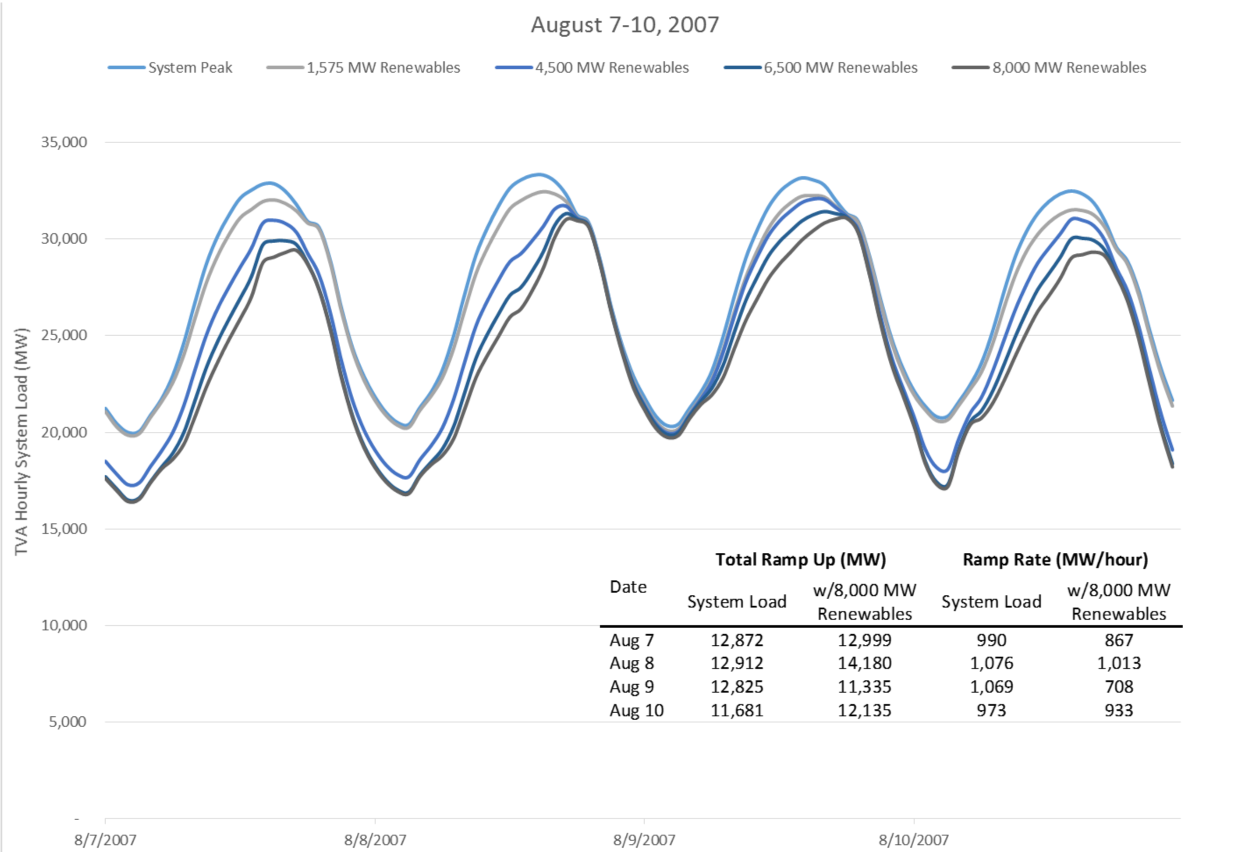
[28] Hoagland, J., *Utility Planning Challenges*, Tennessee Valley Authority, Presentation to Tennessee Advanced Energy Business Council Webinar (August 15, 2014).

Instead, the main result of adding renewable energy into a ramp rate analysis is that some hours have increased ramps, and other hours have decreased ramps. To illustrate extreme operating conditions, two episodes were selected from each utility dataset.

The first episode was selected to represent a system peaking event, identifying a multi-day period with peaks in excess of the utility's forecast annual peak.[29] Coincidentally, for all three utilities, the August 7-10, 2007 episode was selected as a highly challenging peaking event. The TVA case study, illustrated in Figure 9, provides a good example of how substantial levels of renewable energy could affect utility systems in the Southeast during challenging summertime hours.

Figure 9: TVA Load Shape, 0 – 8 GW Renewable Energy Scenarios, Summer Peak Episode



Date	Total Ramp Up (MW) System Load	Total Ramp Up (MW) w/8,000 MW Renewables	Ramp Rate (MW/hour) System Load	Ramp Rate (MW/hour) w/8,000 MW Renewables
Aug 7	12,872	12,999	990	867
Aug 8	12,912	14,180	1,076	1,013
Aug 9	12,825	11,335	1,069	708
Aug 10	11,681	12,135	973	933

Similar case studies for the other two utilities are provided in Appendix C. As summarized in Figure 10, adding renewable energy generally decreased the system swing on each day of the episode (ramp up from minimum load to maximum load) and also decreased the maximum ramp rate (averaged over the ramping period). There were some exceptions: TVA and Southern Company's maximum swing increased when renewables were added, but their minimum swing and ramp rates decreased. At the system level,

[29] Each of the six case study episodes span almost the full range of potential renewable energy generation. The Southern Company and TVA scenarios include substantial amounts of both solar and wind resources; average renewable generation capacity factors are about 40% in system peaking events and 50% in low load events. Because the Duke Energy analysis includes mostly solar resources, the average renewable generation capacity factors in the system peaking event and the low load event are lower, about 35%.

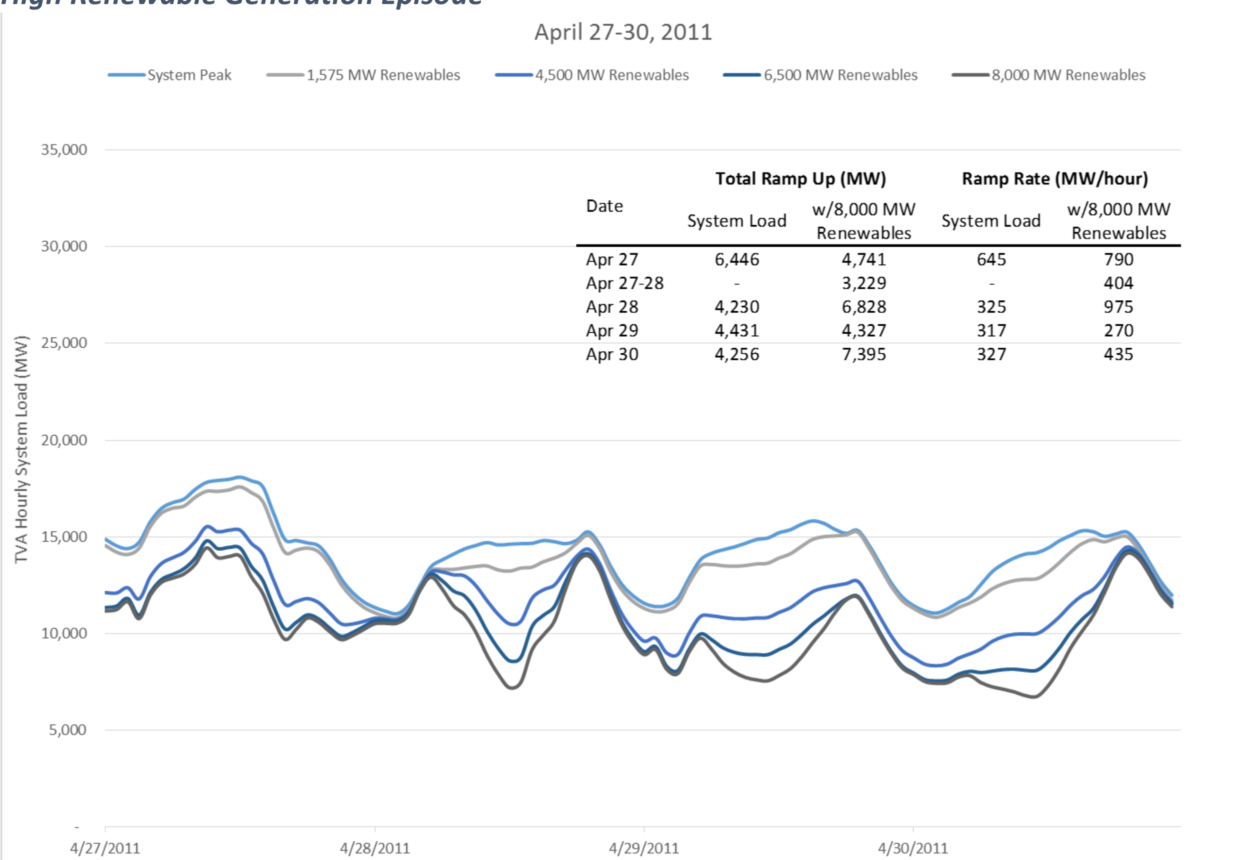
the case studies illustrate how adding renewables will often make system peaking events less challenging to utility operators.

Figure 10: System Peaking Event Case Studies

	System Peak (MW)	Minimum Swing (MW)	Maximum Swing (MW)	Maximum Ramp (MW/hr)
Duke Energy (North and South Carolina)	34,323	12,614	14,225	1,271
Southern Company	36,029	13,100	13,674	1,140
Tennessee Valley Authority	33,315	11,681	12,912	1,076
High Renewable Generation Scenario				
Duke Energy (North and South Carolina)	32,223	10,125	12,632	902
Southern Company	34,217	11,242	14,447	1,032
Tennessee Valley Authority	31,034	11,335	14,180	1,013

The second episode was selected to represent a low load event with high renewable energy generation. The most challenging low load events for each utility occurred in April, but on different dates in 2011 and 2012. The TVA case study, illustrated in Figure 11, provides a good example of how substantial levels of renewable energy could affect utility systems in the Southeast during low load periods with high renewable generation.

Figure 11: TVA Load Shape, 0 – 8 GW Renewable Energy Scenarios, Springtime Low Load / High Renewable Generation Episode



As summarized in Figure 12, the swings and ramp rates experienced with or without renewables during springtime low load events are substantially less than those experienced during system peaking events. However, adding renewables does drive several noteworthy changes during low load events, including:

- Generally increases the size of daily swings.
- Can cause the system to add a second daily minimum/maximum, particularly if wind resources are not added to balance the solar resources. For TVA and Southern Company (with wind balancing solar), an additional minimum/maximum event was added on only one day. But for the Duke Energy scenario (with mainly solar resources), additional minimum/maximum events were added on each day of the episode.
- Generally increases the ramp rates – but the ramp rates still remain significantly lower than those experienced during system peaking events.

Overall, it would be fair to conclude that adding renewable energy would increase operational challenges during springtime low load events. But it would also be important to note that the operational responses challenges would remain significantly less challenging than those needed to manage system peaking events.[30]

Figure 12: Springtime Low Load / High Renewables Event Case Studies

	System Peak (MW)	Minimum Swing (MW)	Maximum Swing (MW)	Maximum Ramp (MW/hr)
Duke Energy (North and South Carolina)	17,857	3,307	6,616	641
Southern Company	21,062	3,405	7,702	804
Tennessee Valley Authority	17,975	4,230	6,446	645
High Renewable Generation Scenario				
Duke Energy (North and South Carolina)	17,857	2,220	5,616	891
Southern Company	18,458	4,897	7,671	979
Tennessee Valley Authority	14,432	3,229	7,395	975

To place these case studies in context, the entire data set was examined statistically for individual resources as well as the combined resource scenarios. Ramp rates were calculated over 1 hour increments.[31] This provided a broad view, considering hours in which renewable energy improved system ramp rates as well as those in which ramp rates became more challenging.

The statistical analyses demonstrates that solar power deployment will not cause an increase in the frequency or severity of hourly ramp rates, even when nameplate solar capacity represents as much as one-third of peak system demand. One reason for this finding is that the sun is almost always shining during peak hours. For example, on the TVA system, solar systems can produce at least 45% of nameplate capacity during 99% of the highest demand hours. The idea that solar might suddenly

[30] As noted throughout this document, the analysis was restricted to the system level and did not include consideration of localized issues that might require dispatch or transmission contingency planning.

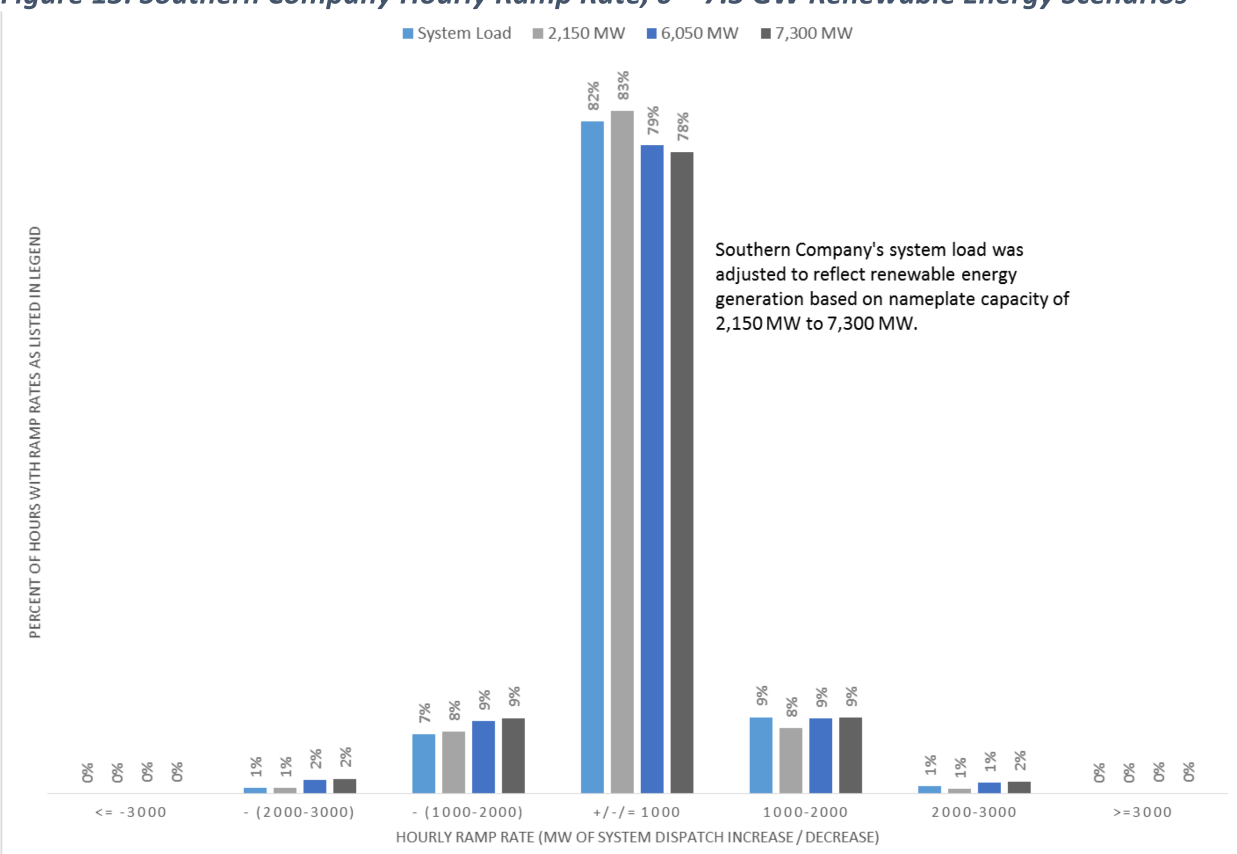
[31] Three hour ramp rates were also calculated for a portion of the analysis, but the results were not sufficiently different from the one hour ramp rate studies to suggest any benefit to more extensive study.

disappear from the TVA system during a peak demand period is simply not supported by careful analysis.

Wind power resources (including both in-region and imports via HVDC) will drive some increase in the frequency of ramping events. The main impact appears to be in terms of ramping the system down at a greater frequency. Fortunately, this impact can be mitigated by introducing contract terms that provide the utility with the opportunity to curtail wind generation to allow for other resources to be ramped down more gradually (after a brief curtailment, the wind generation would be restored to full output). The analysis also shows that wind power will not challenge system operators with a new class of large ramp rates, even when nameplate wind capacity represents as much as one-third of peak system demand.

Examined in combination (as is likely to occur in practice), higher levels of solar and wind energy deployment are likely to result in an increase in the frequency of higher ramp rates. For example, as illustrated in Figure 13, initially with the introduction of solar resources, the frequency of high ramp up rates decreases. The main adverse impact on ramp rate frequencies on the Southern Company system relates to the introduction of HVDC wind resources, but the impacts are relatively modest. As this example suggests, the increase in the frequency of hourly ramp rates in excess of 1,000 MW per hour is likely to be gradual and predictable.

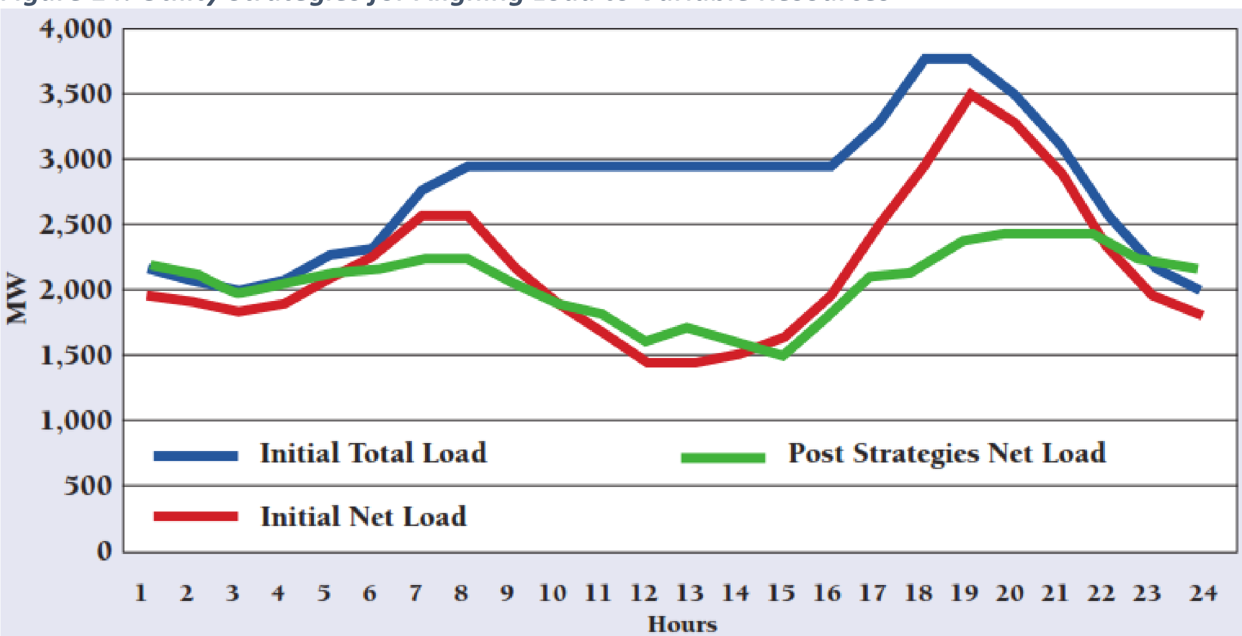
Figure 13: Southern Company Hourly Ramp Rate, 0 – 7.3 GW Renewable Energy Scenarios



Because any adverse impact on ramp rates will be gradual, predicable and not fundamentally different from existing operating conditions, utilities should find these changes manageable. To the extent that the increase in the *number* of hours with higher ramp rates is a concern, there are a number of readily available strategies that utilities could implement to better align load to variable renewable energy resources. Although no single strategy is a "silver bullet," a recent report by the Regulatory Assistance Project explains how several steps taken in combination, could allow utilities to nearly flatten load (see Figure 14).[32] The effectiveness of those steps for specific Southeastern utilities is not examined in this analysis, but certainly utility decisions to adopt (or reject) renewable energy resources should not be made without considering the combined effect of operational strategies.

In the Southeast, the California "duck" won't hunt. Quite simply, solar production and system demand are more fortunately aligned in the Southeast than in California. Geographic and system-specific factors result in the Southeastern solar resource actually *reducing* system ramp rates, at least up to a point. Concerns illustrated by the California ISO "duck curve" are surely valid in California, when it reaches much higher deployment of renewable energy generation than the Southeast is currently contemplating. Not only do these conditions not exist in the Southeast, the east-west orientation of load and other attributes of geography and weather mean that the "duck won't hunt" in the Southeast.

Figure 14: Utility Strategies for Aligning Load to Variable Resources



6. Remaining Uncertainties About Operational Constraints and Attributes Associated with Renewable Energy Development in the Southeast

While introducing substantial amounts of variable resources into a utility system represents real change for Southeastern utility systems, this analysis illustrates methods that utilities could use to plan for and manage the transition to renewable energy. For utilities to fully incorporate these findings into their planning practices, several additional steps, requiring access to confidential utility data, would be necessary.

[32] Lazar, J., *Teaching the "Duck" to Fly*, Regulatory Assistance Project (January 2014).

First, the System Peak Hours (SPH) method utilized for this analysis should be validated in comparison with a full Effective Load Carrying Capacity (ELCC) study. While the ELCC study method may not be well-suited to forecasting if the operating characteristics of future generation fleets are too uncertain, both methods can be used to study historical conditions for benchmarking purposes.

Second, a formal reserve margin study could be conducted to guide the development of plans to ensure that the introduction of large scale renewable energy would not adversely affect system reliability. This would effectively combine the results of a system planning study, a generation forecast study and the application of the SPH (or ELCC) method to assess the overall reliability of future generation fleets.

It is also worth acknowledging that these results may or may not be generalized to other Southeastern utilities. SACE plans to extend these analyses to include utilities in peninsular Florida and smaller utilities elsewhere in the Southeast. To the west or north of the utilities studied, regional authorities such as PJM have adopted means of analyzing renewable energy resource to ensure reliable system operations.

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Appendix A

System Peak Hours Method: Dependable Capacity Factor Analysis for Generic Renewable Energy Resource Development in the Southeast

In determining whether a utility has adequate resources to meet its forecast system requirements, Southeastern utilities appear to have adopted capacity factor-based approximation methods for measuring the dependable capacity factor (DCF) of renewable energy resources. (Elsewhere these may be referred to as an on-peak capacity value, a generation capacity credit, or by some other nomenclature.)

A capacity factor-based approximation method is the easiest, but least sophisticated method for measuring the DCF of variable renewable resources. A number of different methods for this measurement have been developed and applied, suggesting that utility planners have not coalesced around an ideal balance between simplicity and sophistication. The National Renewable Energy Laboratory (NREL) has categorized these methods into four groups, as summarized in Figure 1, of which the preferred metric for measuring the DCF is the effective load carrying capability (ELCC) method.

Figure 1: Approaches to Measuring the Dependable Capacity Factor for Variable Renewable Energy Resources, in Order of Increasing Difficulty[1]

Name	Description	Tools Required
1. Capacity factor approximation using net load	Examines RE output during periods of highest net demand	Spreadsheet
2. Capacity factor approximation using loss of load probability (LOLP)	Examines RE output during periods of highest LOLP	Spreadsheet
3. Effective load-carrying capacity (ELCC) approximation (Garver's Method)	Calculates an approximate ELCC using LOLPs in each period	Spreadsheet
4. Full ELCC	Performs full ELCC calculation using iterative LOLPs in each period	Dedicated tool

The more difficult methods require use of loss of load probability (LOLP) data. LOLP is a probability estimate of how often the load on a power system is expected to be greater than the capacity of the generating resources. LOLP data are derived from, among other data, a "complete inventory of conventional generation units' capacity, forced outage rates and maintenance schedules."[2] With Southeastern utilities in significant flux, considering a high number of ongoing plant retirements and new generation in process, it is impractical for a non-utility planning study to obtain a useful forecast with a "complete inventory" of these data. Even for a utility planning department, creating such a

[1] Denholm, P. et al., *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*, National Renewable Energy Laboratory, NREL Technical Report NREL/TP-6A20-62447 (September 2014), p. 29.
[2] Keane, A. et al., "Capacity Value of Wind Power," *IEEE Transactions on Power Systems* (v. 26, no. 2), Task Force on the Capacity Value of Wind Power, IEEE Power and Energy Society (September 2010), p. 3.

forecast prior to committing to a particular resource plan may be too resource intensive. Thus, an methods that require LOLP data may not be the best tool for long-term planning studies.

However, In reviewing the methods used by Southeastern utilities for measuring DCFs, to the extent those methods have been publicly explained, it appears that do not capture both the short term and the annual variability of renewable energy resources, particularly their correlation with demand in a variety of circumstances over a multi-year period.[3] In order to address this shortcoming without engaging in an impractical forecasting effort, a new variant of the capacity factor-based approximation method, the System Peak Hours (SPH) method, is applied to three vertically-integrated utilities in the Southeast. The SPH method is effective at capturing both the short-term (hourly) correlation with demand, as well as the annual variability of renewable energy resources. The SPH method improves on other capacity factor- based approximation methods by using a matched, multi-year set of renewable energy and utility system demand data.

1. Description of the System Peak Hours (SPH) Method

The System Peak Hours (SPH) method calculates dependable capacity factors (DCFs) that are a simple average of capacity factors during winter and summer peak hours. Peak hours are defined as hourly loads exceeding 90% of the forecast annual peak, with the number of hours included in this definition varying from year to year depending on how actual system demand relates to the forecast annual peak. The calculation is performed using a dataset that includes modeled (or actual, if available) capacity factors for renewable energy resource technologies and system loads for individual hours spanning several years, with the validity of the method increasing as the number of years included in the dataset becomes larger.[4]

The use of the forecast annual peak as the basis for selecting the peak hours is the *first* distinctive feature of the SPH method. Because the hours being selected are precisely those in which system demand is likely highest relative to available capacity, it is essential that the load and variable resource datasets be time-correlated. The importance of the correlation between the definition of peak hours and system capacity planning standards is that the definition should approximate the selection of hours with higher LOLP. Referring back to Figure 1, the SPH method does not fall neatly into either category of capacity factor-based approximation methods: it does not use highest net demand, because selection of high demand hours is relative to forecast demand, but neither does it rely on LOLP. The SPH method has characteristics of each category.

The SPH method follows a multistep calculation process – listed here - in order to estimate the DCFs associated with types of renewable energy resources. Note that each step in the method is also illustrated using a causal loop diagram approach, in Figures 2-5.

- Step 1: Representative load shapes of the different renewable resources (e.g., various solar and wind technologies) are estimated using modeled production load shapes. The modeled

[3] Keane (2010), p. 4.

[4] Using a larger number of years provides a wider range of climate, economic, and customer load conditions over which to test the potential interaction of renewable energy and system demand. The SPH method applied to very short time periods could generate unrepresentative results. The specific data coverage used in this analysis is discussed in Section 4.

production data should be specific to actual or reasonably feasible production sites[5] located in, near or proposed for interconnection with the service territory of the specific analyzed utility. The data used in this analysis are described in Section 4. Based on these site-specific, modeled production data, system capacity factors are calculated as a simple average annual capacity factor (and thus do not depend on the SPH method).

Peak hours are selected by comparing hourly system load to the utility's forecast annual peak. Hours with system load greater than 90% of the utility's forecast annual peak for the respective planning year are considered peak hours. The data are described in Section 4.

Seasonal DCFs are estimated individually, at each individual renewable energy production site, assuming no prior renewable energy development (existing system loads). Each DCF value is simply the average of capacity factors during the applicable peak hours.

The representative load shape (or production curve) for the generic system resources are created using a weighted (or simple) average of the hourly production data for each site-specific resource dataset. For the Tennessee Valley Authority (TVA) analysis, in order to select "best" sites to focus on resources that would be most preferred by the utility, sites were selected based on advantageous system capacity factor and DCFs. The selection criteria and averaging process should be reasonably transparent and related to the planning study objectives.

- Step 2: Average DCFs and net resource system loads are determined for the representative renewable resource load shapes. These representative resource load shapes are particularly useful for integrated resource planning studies, which typically constrain the number of resources considered in the modeling process and hence would not evaluate specific projects.

  The average DCFs for each resource technology are estimated individually in the same manner as described in Step 1 for the individual sites. The net resource system loads are determined by detracting from the system load shape the various resource hourly load shapes.

- Step 3: Seasonal DCFs for the renewable resource load shapes are calculated. Seasonal (winter and summer) DCFs are needed because most capacity planning models utilize a two-season capacity rating approach. In a utility planning context that applies a different capacity rating approach, the method should be adapted accordingly. The peak hours for these net system loads are selected using the same criterion as in Step 2.

- Step 4: Seasonal DCFs and dependable capacity supplied at a utility portfolio level are calculated by assuming specific levels of resource deployment (tranches) over time. However, rather than using the utility's forecast annual peak, a seasonally modified net annual peak is used. The peak is adjusted downward, taking into consideration the seasonal dependable capacity supplied by the renewable energy resources and also the need to ensure that those resources are augmented by the utility's reserve margin (typically 15%). A minimum of three tranches of

[5] The sites should be representative of likely resources that the project developers and the utility would be more likely to develop during the planning period in which the DCFs will be used. So for example among a random sample of solar production sites, a cross-section of sites with advantageous annual capacity factors and on-peak production should be used.

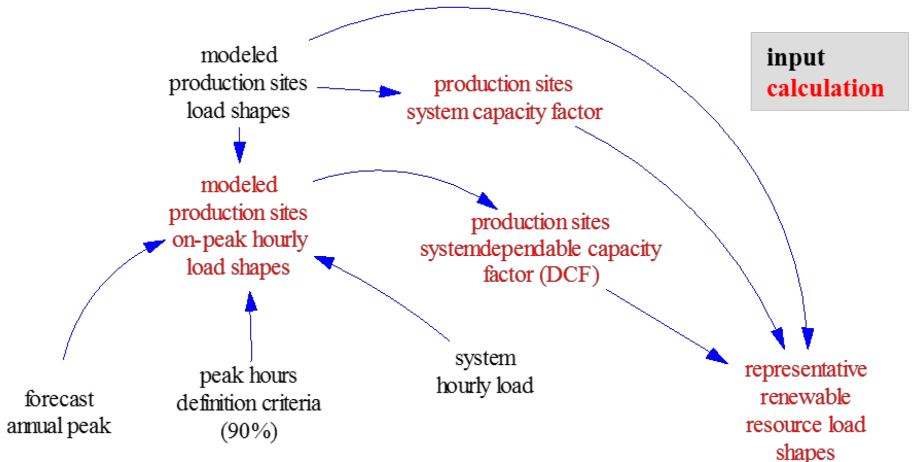
renewable resources development have been considered for all analyzed utilities, as described in Section 6.

The seasonal modification of the forecast net annual peak is the *second* distinctive feature of the SPH method. The seasonally modified net peak is particularly important because, as solar power is developed to scale, the net system peak may shift from primarily summer afternoon hours to include more summer evening and winter morning hours. Since the output of solar systems is relatively small (or zero) during those hours, the contribution of solar power to meeting system peak needs would be diminished. Thus, in Step 4, the forecast annual peak is modified for winter and summer periods as the forecast annual peak, minus the seasonal net dependable capacity for the renewable energy resources included in the scenario, minus the portion of the seasonal net dependable capacity needed to meet reserve margin requirements (typically 15%).

Another reason it is important to produce distinct summer and winter dependable capacity ratings for renewable energy resources is to ensure consistency with the manner in which conventional resources are planned. Currently, many planning regions (even those using the ELCC method) calculate only a single, year-round ELCC measurement for renewable energy resources. Yet for conventional, thermal generation resources, it is standard practice to calculate seasonal capacity ratings on a resource-specific basis. As discussed below, the seasonal capacity rating for solar is higher in summer than in winter, but for wind the reverse is true. Thus, the SPH method can be used to ensure that a utility considers the attributes of each resource, whether variable or conventional thermal, using consistent methods.

The seasonal net dependable capacity is calculated as the product of the seasonal net dependable capacity factor and the nameplate capacity of the renewable energy resources included in the scenario. Because the seasonal net dependable capacity factor is the result of this process, the calculation process is iterative until a stable solution is found.

Figure 2: Step 1 - Representative Renewable Resources Load Shapes Estimation

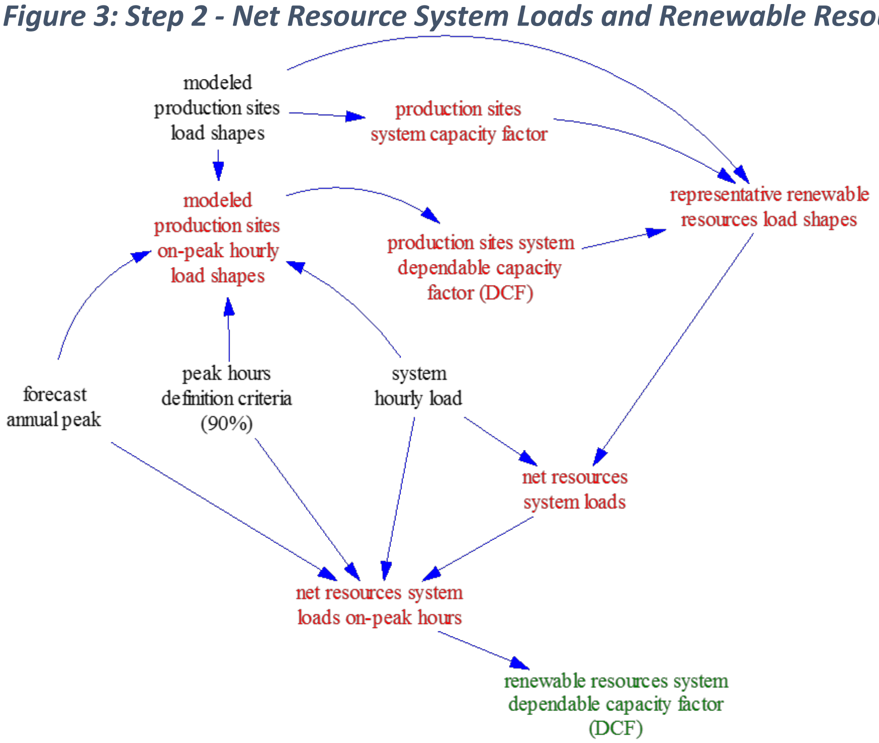


a) Based on modeled production sites load shapes, system capacity factors associated to the individual sites are calculated (and thus do not depend on the SPH method).

b) Peak hours are selected by comparing hourly system load to the utility's forecast annual peak. Hours with system load greater than 90% of the utility's forecast annual peak for the respective planning year are considered peak hours. According to this peak hour selection, specific production sites dependable capacity factor (DCF) are estimated.

c) Finally, using as selection criteria the sites' system capacity factors and dependable capacity factors previously calculated, the representative load shapes of the different renewable resources are estimated as an average load shape of selected modeled production sites load shapes.

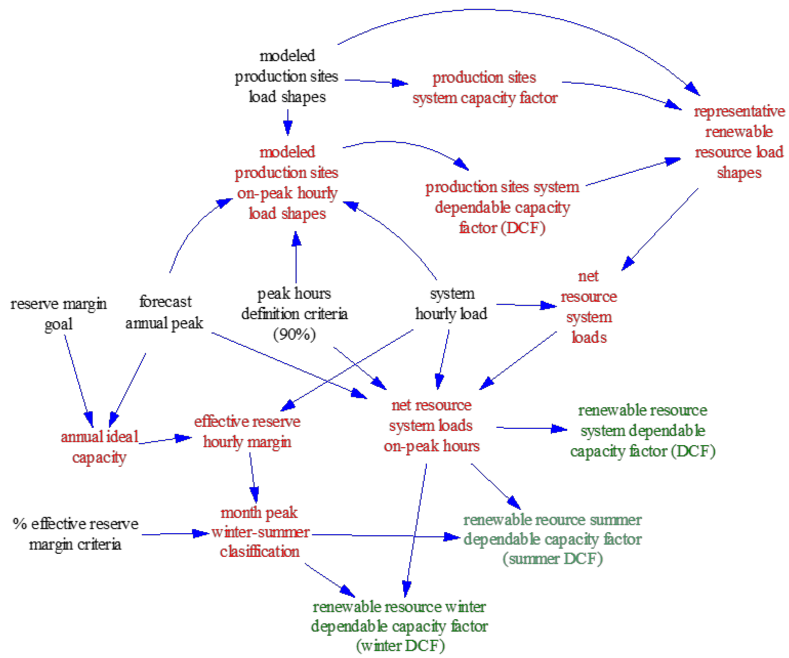
Figure 3: Step 2 - Net Resource System Loads and Renewable Resource System DCF Calculation



a) System average dependable capacity factors are determined for the representative renewable resource load shapes. The DCFs for each resource technology are estimated in the same manner as described in Step 1 for the individual sites as the average of capacity factors during the applicable peak hours.

b) The net resource system load is determined by detracting from the system load shape the renewable resource load shape.

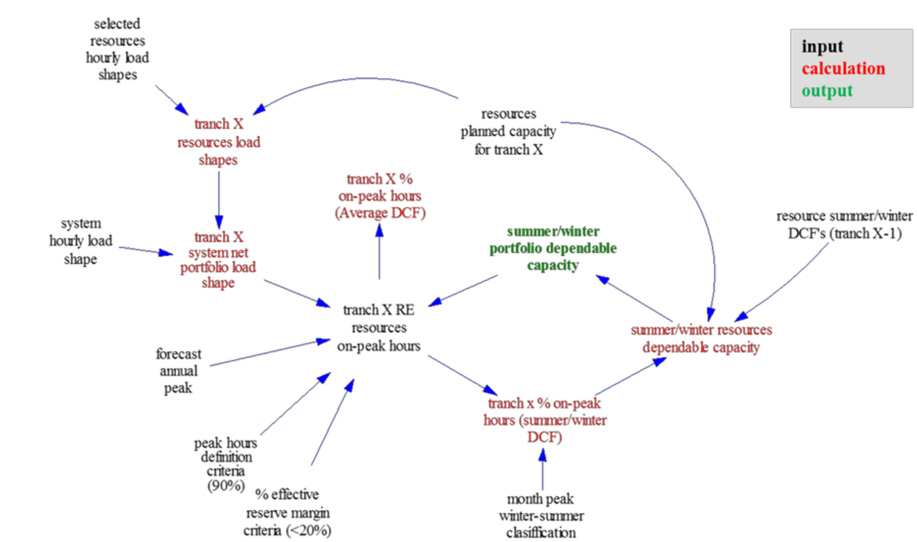
Figure 4: Step 3 - Renewable Resource Seasonal DCFs



Seasonal dependable capacity factors at a renewable resources level are calculated.

The peak hours for these net system loads are selected using the same criterion as in Step 2.

Figure 5: Step 4 - Portfolio DCFs & Average Capacity Deployed Calculation



Seasonal dependable capacity factors (DCFs) and dependable capacity supplied at a utility portfolio level are calculated by assuming specific values of deployment of individual resources through time.

However, rather than using the utility's forecast annual peak, a seasonally modified annual peak is used. The peak is adjusted downward, taking into consideration the seasonal dependable capacity supplied by the renewable energy resources and also the need to ensure that those resources are augmented by the utility's reserve margin (typically 15%).

The resulting adjusted peak might be thought of as an effective forecast peak for other energy resources besides those being studied. A minimum of three scenarios of renewable resources development (Tranches) have been considered for all analyzed utilities, as described in Section 6.

2. Need for a Balanced Method of Establishing Dependable Capacity for Renewable Energy Resources

Utilities plan for a target reserve margin that is designed to minimize the overall cost of reliability to the customer. The target reserve margin is an optimal value: insufficient reserves put customers at risk of either system failures or expensive short-term market purchases, but excessive reserves guarantees that customers will pay for capacity that may not be utilized sufficiently to justify the cost.

As with all energy resources, renewable energy resources contribute to a centrally planned utility's capability to plan for reliable service. Even though variable resources cannot be dispatched to meet increased demands for power,[6] wind and solar resources are often productive during system peak hours and thus contribute to the system's capacity to serve load. The question that the ELCC, SPH and other methods seek to answer is simply "How much conventional capacity can be avoided by the renewables?"

Because most utilities maintain relatively up-to-date reserve margin studies, their target reserve margins already incorporate consideration of these factors for the existing mix of generation resources and the characteristics of the utility systems' customer demand. The SPH method assumes a ceteris paribus approach, where the LOLP is unaffected by any changes to the characteristics of the generation mix or customer demand that occur other than the introduction of renewable energy resources. This is similar to the ELCC method, which holds all other aspects of the system constant, while calculating the difference in loads that can be reliably served by a generation system "with" and "without" a defined level of renewable energy resources.[7]

The SPH method approximates the same basic result: the DCF for each resource is equivalent to the amount of conventional capacity that would not be needed for the generation system to perform at the target reserve margin level. It is important to establish a DCF that is less than the nameplate value of the resource since it is not possible for a variable resource to generate power at 100% of its nameplate capacity all of the time. It is of course also important to establish a DCF that is more than 0%, since the renewable energy resource contributes at least somewhat to meeting on-peak demands.

If the SPH or some other capacity factor-based approximation method is used, the choice of the averaging period for the renewable energy output is a critical decision. Of course, if an ELCC or some other LOLP-based method is available, then that would provide a basis for measuring the DCF on the basis of reliability data. But when averaging is used, a misleadingly high or low DCF measurement can be obtained by excluding (or emphasizing) certain hours that are important (or unimportant) for a reliability measure.

A utility that suggests its method is preferable because it is "conservative" would be reaching a mistaken conclusion. Using a DCF value that is too low would be suboptimal, in that the resulting planning decisions would lead to excess generation capacity on the utility system, at a cost to its customers. Subject to several caveats, the SPH method achieves a balance.

[6] Note that wind resources can be curtailed almost instantaneously. Thus it is inaccurate to refer to wind resources as strictly "non-dispatchable." Many utilities routinely utilize short-term wind curtailments (reductions in output) to help regulate system power fluctuations.

[7] MISO, *Planning Year 2014-2015 Wind Capacity Credit* (December 2013).

3. Calibration of the SPH Method

As mentioned above, the distinctive features of the SPH method are the use of the forecast annual peak as the basis for selecting the peak hours, and the application of a seasonally modified forecast net annual peak. Each of these features could be more finely calibrated by, or in collaboration with, a utility.

Both of these design features rest on the assumption that an "optimal" level of generation (or system capacity target) on a utility system is represented by the forecast annual peak plus the target reserve margin.[8] The SPH method depends on the degree to which the utility's forecast annual (net) peak represents the system size that the utility targets in its capacity planning process and thus represents at least a reasonable approximation of an "optimal" system.

One way in which this approximation could be inaccurate is the choice to use the utility's peak forecast from the prior year. Given the lag between a forecast capacity gap (difference between system capacity and a future target value) and construction of new resources, an earlier forecast might better represent utility decision-making. However, for this analysis, it was determined that the prior year forecast introduced the least complexity in interpretation. Nonetheless, a utility or regulator might reasonably select a different representation of the system capacity target.

Another potential error in the approximation method is that the threshold, 90% of forecast annual (net) peak demand, is somewhat arbitrary. This value was chosen to identify the hours in which load is near the assumed system capacity target, net of variable renewable energy capacity. When load is near the assumed capacity target for the system LOLP should increase (all other things being equal), and the utility is more likely to experience a reliability event during those hours. To calibrate the threshold, the SPH method should be benchmarked against the ELCC method to determine a correlated value (e.g., higher or lower than 90%).

A third way in which a utility or regulator could improve this method would be to use a seasonal, rather than annual, system capacity target. Most utilities in the Southeast use an annual capacity target, almost always corresponding to the summer value but perhaps occasionally the winter target. A seasonal system capacity target should take into consideration the variation of seasonal capacity ratings for the thermal generation fleet as well as the variability of seasonal loads.[9] Making this improvement would likely result in two counteracting changes. On one hand, the 90% threshold would likely be applied to a slightly higher system capacity rating for winter (reflecting greater thermal efficiencies), reducing the number of winter hours studied. On the other hand, for utilities with substantial customer use of electric resistance space and water heating, winter peaks may be somewhat more variable than summer in a way that is naturally considered in the ELCC method but would be missed in the SPH method. In other words, the LOLP for a given load might be higher in winter than in summer, indicating an increase in the

[8] Another benchmark, the weather normalized annual peak, was considered and tested for use in this method in place of the forecast annual peak. However, weather normalized annual peaks are not readily available for most utilities. A better reason for selecting the forecast annual peak assumption is that it is more closely related to capacity planning methods than the weather normalized annual peak. Whatever "optimal" system benchmark is chosen, it should be a routinely calculated, objective value. For example, if hourly LOLP data are available, those values could be used to increase the sophistication of this method.

[9] Seasonal peak forecast values were not used because available capacity should be representative of the forecast annual peak regardless of season. For example, winter capacity should be equal to, or greater than, the forecast annual peak plus reserve margin, even if the forecast winter peak is smaller than the summer peak.

number of winter hours studied. Because addressing both of these considerations would cancel out to some extent, a seasonal refinement would likely have little overall impact on the DCFs for renewable energy resources, particularly in the context of the summer peaking utilities studied in this analysis.

4. *Description of Study Data*

A. Annual Peak Demand Forecast

Utilities file Federal Energy Regulatory Commission (FERC) Form 714 on an annual basis. This form includes a ten-year projection of peak demand. For this analysis, the annual forecast selected was the final forecast (for example, the 2010 peak demand forecast used in this project would be the one filed in 2009). For unknown reasons, FERC does not have forecasts for all years for some utilities.

- *Duke Energy:* Reflecting demand from Duke Energy Carolinas and Duke Energy Progress (or its predecessors) using FERC Form 714 data (1997-2012).
- *Southern Company:* Reflecting demand from Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Savannah Power (when applicable) using FERC Form 714 data (2001-2012).
- *Tennessee Valley Authority:* FERC Form 714 for the periods 1997-2002 and 2007-2012. For the period 2003-2006, the FERC Form 714 peak demand forecast values were not available from FERC. Weather normalized peak values obtained from a TVA graph were used instead.

For the utilities studied in this project, the summer peaks were used in all cases because they were highest. As discussed in Section 6 of the report, the SPH method might be improved by utilizing winter peak forecast as well.

B. Hourly Load

FERC Form 714 also includes an annual report of system load on an hourly basis. One challenge with these data in general is that utilities follow different practices in dealing with daylight savings time, and even vary those practices from year to year somewhat. As discussed above, it is essential that the utility load data be accurately matched with renewable energy generation datasets.

For Duke Energy and Southern Company, the hourly load data sources were the same as discussed above in Section 4.A. During discussions with TVA staff regarding calculations related to this analysis, discrepancies were identified between TVA's internal data records and the data obtained from TVA's FERC Form 714 filings. TVA supplied a complete dataset covering 1998-2012, which was used in lieu of the FERC Form 714 filings.

C. Solar Power Output

SACE contracted with Clean Power Research to simulate hourly production for two PV fleets – a fixed fleet and a tracking fleet. Specific sites were selected by SACE to be geographically dispersed across utility service areas, typically located near existing thermal generation, load centers or major transmission system intersections.

- *Duke Energy:* 12 sites across service territory (see Figure 6(A)), studied as utility-scale projects

- *Southern Company:* 24 sites (see Figure 6(B)) studied as utility-scale projects, including 15 sites within the service territory, plus 9 sites in close proximity, subdivided into sites likely to be delivered to Georgia Power, and sites likely to be delivered to other Southern Company affiliates
- *Tennessee Valley Authority:* 26 sites across service territory (see Figure 6(C)), with 10 higher performing sites selected to represent those most likely to be developed as utility-scale projects and the "all sites" average for fixed mount systems selected to represent large commercial installations, typically 5 MW or smaller on large rooftops or adjacent to business facilities

Clean Power Research's simulation used its SolarAnywhere FleetView modeling services, standard resolution (10 km x 10 km x 1 hour resolution).

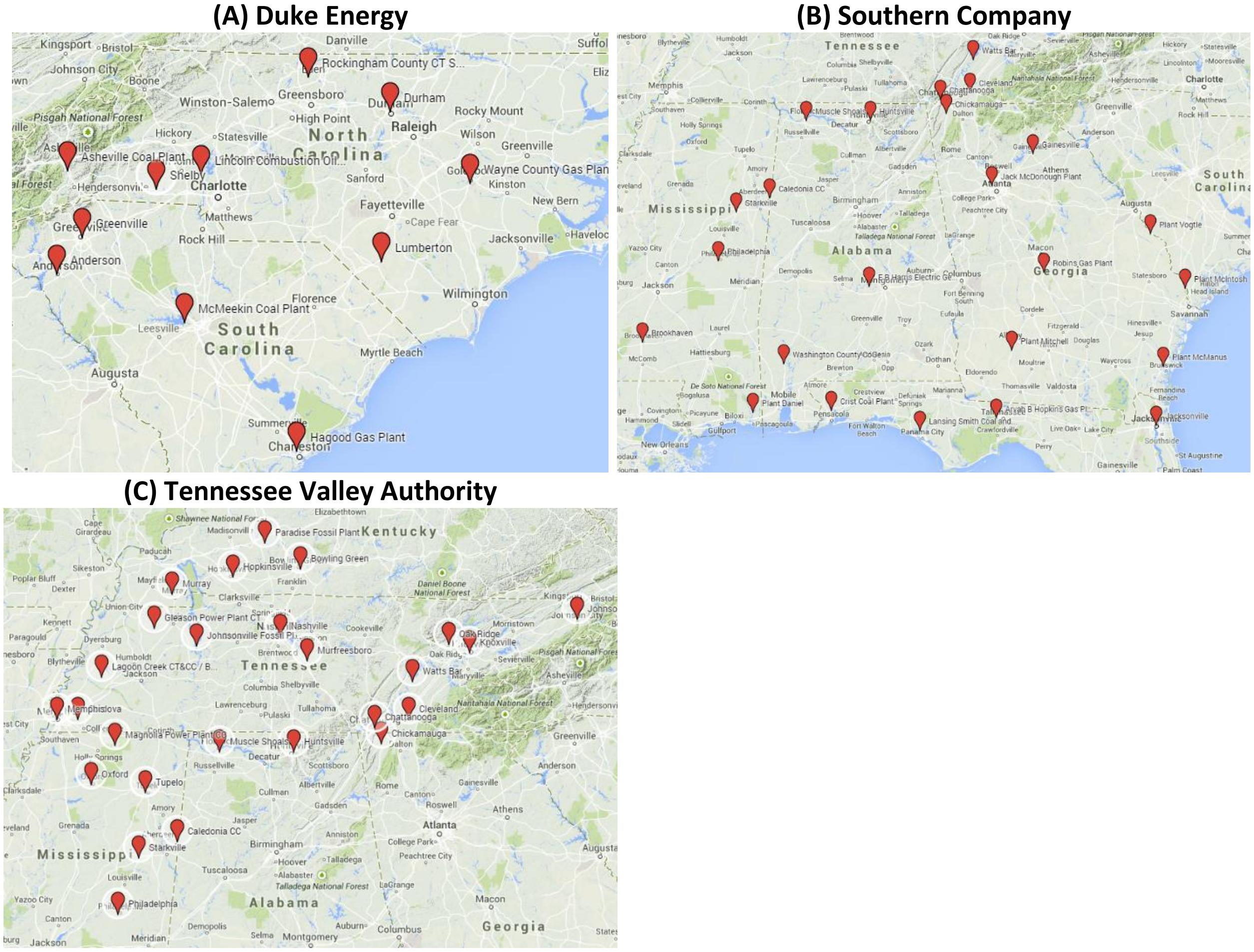
- Fixed tilt fleet: 1 MW_{AC}, south-facing, 20-degree tilt angle
- Tracking fleet: 1 MW_{AC}, N/S tracking axis, 0-degree tilt angle, tracking rotational limit of +/- 45°

All systems configured with 4,800 modules in 12 rows with a relative row spacing of 2.5 and combined DCPTC[10] rating of 1,200.5 kW. A general derate factor of 85% was used along with an inverter with a CEC weighted average efficiency of 98% and an albedo of 0.15.

Valid production data for smaller business and residential systems was not available for this project. Ideally, a simulated fleet of rooftop systems that takes into account the experience of other utilities and the typical roof designs of Southeastern buildings would need to be completed. An estimated cost for such an analysis was prepared by Clean Power Research to complement this study, but funding was not available from SACE or any utility to complete the analysis.

[10] Direct Current Performance Test Conditions. Note that other than this specific reference to direct current, all capacity and energy results are reported in alternating current (AC) results.

Figure 6: Solar Power Study Sites for (A) Duke Energy, (B) Southern Company and (C) Tennessee Valley Authority



D. Regional Wind Power Output

The Southern Wind Energy Association (SWEA) contracted with AWS Truepower to simulate hourly production for eight wind farm areas in the TVA service territory. The eight study sites, illustrated in Figure 7, were selected for study based on prior studies and data that identified good prospects. The study areas were not selected as specific locations that any company is developing a wind project, and during the selection, neither SACE nor SWEA solicited or received developer input of this type, nor were any particular environmental suitability screens applied.

The AWS windTrends national wind map is modeled at a 200 meter resolution and validated using a variety of surface station data. For the TVA analysis, AWS utilized a total of 89 validation points in the following states of interest: Tennessee, Alabama, Mississippi, Arkansas, Missouri, Kentucky, and North Carolina. Due to the interpolation of data from these points to the sites of interest, the results should not be considered indicative of sites at the exact locations, but of wind conditions in the general area of the sites included in the analysis. Based on review of relevant data and consultation with various experts, the resulting wind resource is a reasonable representation of modeled data that might result from a more extensive prospecting and site selection process.

Because wind developers will prospect for better sites, the TVA analysis uses the data associated with the five best sites rather than all eight sites. This does not mean that the areas associated with the three less attractive sites should be considered undevelopable; there may be geographic features in that region whose characteristics are not appropriately modeled at the resolution available in the AWS windTrends dataset.

Due to the expense associated with obtaining these data, data for sites located within the Southern Company or Duke Energy service areas were not purchased. For Southern Company, the five sites from the SWEA data sited closest to its service territory were selected as indicative of resources that might be available for direct interconnection with the Southern Company transmission system. Regional wind was not studied for Duke Energy due to lack of suitable data.

Figure 7: Wind Power Study Sites

E.   HVDC wind-generated power imports

There are two proposed HVDC transmission projects anticipated to interconnect in the Southeast. Clean Line Energy Partners is developing the Plains and Eastern Line with a capacity of 3500 MW, connecting wind resources in or near western Oklahoma with TVA's Shelby Substation (near Memphis, TN).[11] Pattern Energy is developing the Southern Cross Line, connecting wind resources on the ERCOT system with TVA and Southern Company in Mississippi, with two phases of 1500 MW bidirectional capacity.[12] In turn, power from these projects can be wheeled through to other interconnected systems in the Southeast, subject to transmission constraints.

Limited generation data are available for these projects. Clean Line Energy Partners contracted with 3tier to simulate hourly production at two hypothetical wind farms in Oklahoma. Details of this study have been provided to TVA, and SACE was permitted to analyze these data subject to certain

[11] See http://www.plainsandeasterncleanline.com/site/home
[12] See http://www.southerncrosstransmission.com/

confidentiality protections. Wind industry experts were consulted and generally agree that similar wind profiles are likely to be available from the Texas Panhandle for supply to the ERCOT grid and then to the Southern Cross project. For this reason, the 3tier data were used as the basis for calculating the potential output from both proposed HVDC transmission projects.

Wind power delivered via HVDC transmission differs in important respects from power delivered through a direct interconnection with a utility transmission system. One difference is that the delivery constraint at the point of interconnection (e.g., TVA's Shelby Substation) is likely to be different from the peak power available from wind farms under contract for delivery. According to developers of both projects, it is likely that the transmission lines would "oversubscribe" their available capacity due to the basic business model for the project. During a few peak hours in which all wind farms under contract are operating at or very close to 100% of nameplate capacity, the transmission operator would need to utilize a contract clause to slightly curtail (or redirect) wind farm output to limit delivery to the operating constraint. While curtailments might appear to be costly, the cost would be compensated for during other hours in which the "oversubscription" would enable the transmission line to carry the "extra" power and thus increase revenues.

There are several other significant differences. Clean Line's HVDC technology may require a minimum throughput to maintain operating voltage. Pattern Energy's business model envisions bi-directional flows, with the potential for energy from the Southeast to be utilized within ERCOT. System rules in ERCOT also provide for a certain degree of advance planning and firming of power delivery. Finally, for power delivered via wheeling through another utility's transmission system, adjustments for additional line losses are necessary.

Each of these factors was addressed to the extent feasible in the development of the "as-delivered" HVDC wind power hourly capacity factors.

- *Duke Energy:* Consistent with input from various experts, the Clean Line HVDC resource was assumed, using oversubscription factors and a minimum delivery threshold selected by SACE to represent a likely business model. Line losses on the TVA system (used for wheeling) were set at 3% based on TVA practices. Due to anticipated transmission constraints, this resource was limited to 500 MW delivered.
- *Southern Company:* Clean Line and Pattern Energy's projects were modeled separately. The Clean Line HVDC resource was modeled the same as for Duke Energy except that no specific transmission delivery constraint was identified. Pattern Energy's project was modeled using oversubscription factors selected by SACE to represent a likely business model.
- *Tennessee Valley Authority:* Consistent with the preferences of TVA planners, a generic HVDC resource was created. The oversubscription factor and minimum delivery threshold were set at the average of those for the business plans assumed for the Clean Line and Southern Cross projects.

It should be emphasized that this resource characterization is not an attempt to model specific contract terms. Instead, the "as-delivered" characterization reflects operating constraints and opportunities in a likely business model that would form a *starting point* for negotiating specific terms and conditions that might establish operational guidelines.

5. *Application of the SPH Method at Initial Stages of Renewable Energy Resource Development*

The dependable capacity factors (DCF) for each resource, for each utility system, are summarized in

Figure **8**. As discussed in Section 1, the DCF is calculated as the simple average of capacity factors during winter and summer peak hours. Peak hours are defined as hourly loads exceeding 90% of the forecast annual reserve requirement, which is the forecast annual peak plus reserve margin.

Values are presented for winter, summer, and annual (planning year) periods. Because most utility resource planning models require distinct winter and summer capacity ratings for each resource, the annual DCF is provided mainly as reference to help illustrate the relative weight of each seasonal capacity rating. Each DCF is compared to the utility's current publicly-provided rating (if available). The annual capacity factor (CF) for each resource is also presented for comparison; these values area simple average (percent of rated annual MW_{AC} output), not requiring the SPH (or any other) method.

Because Southern Company's distribution utilities contract for power individually (although subject to a joint dispatch arrangement), DCF values for solar power were calculated separately for interconnection to Georgia Power Company and to the other three companies. This was also important due to the more advanced state of Georgia Power's adoption of solar power as discussed in Section 6 below.

Figure 8: Annual and Seasonal Dependable Capacity Factors, Assuming No Substantial Prior Renewable Energy Development

	Solar – Tracking	Solar – Fixed	Regional Wind	HVDC Wind Imports
Duke Energy (North and South Carolina)				
Annual CF	23%	21%	-	57%
Summer DCF	66%	56%	-	43%
Winter DCF	12%	10%	-	67%
Average DCF	63%	54%	-	44%
Duke Adopted DCF[13]	*46%*	*46%*	*13%*	*n/a*
Southern Company – Georgia				
Annual CF	24%	21%	-	-
Summer DCF	61%	51%	-	-
Winter DCF	23%	17%	-	-
Average DCF	61%	51%	-	.
Southern Company – Alabama, Mississippi & Florida				
Annual CF	24%	21%	38%	66% / 57%
Summer DCF	61%	53%	10%	46% / 56%
Winter DCF	16%	11%	36%	84% / 96%
Average DCF	60%	52%	10%[14]	47% / 57%[15]
Southern Adopted DCF	*n/a*	*n/a*	*n/a*	*n/a*
Tennessee Valley Authority				
Annual CF	23%	20% / 20%	38%	62%
Summer DCF	66%	56% / 53%	9%	53%
Winter DCF	14%	13% / 14%	36%	62%
Average DCF	60%	51% / 49%	12%	54%
TVA Adopted DCF	*68%*	*50% / 50%*[16]	*14%*	*14%*

[13] Duke Energy Carolinas, *Integrated Resource Plan* (September 2014); and Duke Energy Progress, *Integrated Resource Plan* (September 2014). For solar, an average of the DEC 46% and DEP 44% “contribution to peak load” value is used.

[14] Proxy data from sites in TVA service area, but close to Alabama Power or Mississippi Power service areas.

[15] Clean Line Energy’s Plains & Eastern Line and Pattern Energy’s Southern Cross HVDC projects reported separately. The differences are mainly due to losses imposed by intermediate AC transmission wheeling of the Clean Line power through TVA; Pattern Energy would be delivered directly. The underlying wind data are identical.

[16] For TVA, the first figure refers to utility-scale fixed mount solar systems, and the second figure refers to commercial-scale fixed mount solar systems. For TVA, the higher performing systems were concentrated in the western portion of the TVA system, so the “all sites” solar production data were used to represent commercial scale systems. For other utilities, higher performing systems were not as geographically concentrated so this distinction was not utilized.

6. *Scenarios for Buildout of Renewable Energy Resource Development*

One reason the SHP method was developed was to investigate the impact of large-scale renewable energy development on utility systems. As renewable energy resources are deployed at scale, the value they offer to the system as capacity resources changes.[17] The DCF of each individual resource is affected significantly by the deployment of any type of variable resource.

As a result of some of the initial calculations during the analysis, the renewable energy resource development scenarios were selected and studied consistent with these general patterns.

- DCF values for each specific solar resource (i.e., commercial-scale fixed mount solar systems) were affected by the total solar resources deployed, regardless of technology or type, because the performance of each solar resource technology was closely correlated with the others. (This is illustrated below, see Figure 11.)
- Solar tracking resources appeared highly advantageous in terms of DCFs relative to fixed mount systems. However, since the DCFs decline significantly (see Figure 11), it is assumed that while tracking systems might dominate utility-scale development during the early phases of development, fixed mount systems could predominate overall.
- DCF values for regional wind resources and HVDC wind resources were not as closely correlated, so are best thought of as distinct resources. (This can be seen by comparing Figure 12 with Figure 13.)
- Significant differences in DCF values occurred only after development of roughly a gigawatt (GW) of additional renewable energy (see Figure 12 and Figure 13).

Based on these patterns, as well as information about the schedules of various projects or utility regulatory proceedings, a renewable energy development scenario was developed for each utility in the study. For example, utility avoided cost proceedings typically occur on a biennial basis, so each utility scenario is expressed as three to four "tranches," representing blocks of renewable energy that could be developed in two or three year periods.

The scenarios were developed for each specific utility based on publicly available information about existing projects, potential projects and general industry trends. In general, the goal was to have a balanced portfolio of about 4,000 MW of solar and wind each. This was not precisely achieved due to the lack of suitable data for regional wind projects. The assumed solar and wind capacity levels for each scenario are presented in Figure 9.

[17] Andrew Mills and Ryan Wiser, "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," LBNL-5933E (December 2012).

Figure 9: Renewable Energy Development Scenarios (MW Nameplate Capacity)

	Solar – Tracking	Solar – Fixed	Regional Wind	HVDC Wind Imports	Total	Energy (Annual Capacity Factor)
Duke Energy (North and South Carolina)						
Tranche 1		1,089	-	-	1,089	1%
Tranche 2	1,000	911	-	500	2,411	4%
Tranche 3	500	500	-	-	1,000	1%
Duke Total	**1,500**	**2,500**	**-**	**500**	**4,500**	**6%**
Southern Company – Georgia						
Tranche 1	750	900	-	-	1,650	2%
Tranche 2	250	-	-	-	250	9%
Tranche 3	250	250	-	-	500	2%
Southern Company – Alabama, Mississippi & Florida						
Tranche 1	250	150	100		500	2%
Tranche 2	750	250	150	2,500[18]	3,650	9%
Tranche 3	250	250	250		750	2%
Southern Total	**2,500**	**1,800**	**500**	**2,500**	**7,300**	**13%**
Tennessee Valley Authority[19]						
Tranche 1	500	175 / 550	350	-	1,575	2%
Tranche 2	50	75 / 150	150	2,500	2,925	9%
Tranche 3	700	150 / 300	100	750	2,000	4%
Tranche 4	400	300 / 600	200	-	1,500	2%
TVA Total	**1,650**	**700 / 1,600[20]**	**800**	**3,250[21]**	**8,000**	**16%**

7. *Application of the SPH Method with Large Scale Renewable Energy Resource Development*

Utilizing the scenarios described above, the resulting DCFs can be specified on a summer and winter basis. (The calculation method is described in Section 1, Steps 4-6) The DCFs calculated for Tranche 1 applies the SPH method with no adjustment to load shape. Beginning with Tranche 2, the load shape is adjusted to net out the effects of the resources included in Tranche 1, and so forth.[22] As a result, the DCF used for a specific technology resource in subsequent tranches is typically lower than for the same resource included in the first tranche.

[18] Clean Line Plains & Eastern: 1500 MW; Pattern Energy Southern Cross 1000 MW.
[19] For the TVA analysis, existing Midwestern wind contracts were not studied because data regarding their hourly production were not available. TVA applies a 14% dependable capacity factor for existing resource contracts.
[20] The first figure refers to utility-scale fixed mount solar systems, and the second figure refers to commercial-scale fixed mount solar systems. See note 16.
[21] This value assumes that the imports are sourced equally from the two proposed HVDC projects.
[22] A degree of regulatory lag, similar to what occurs in avoided cost proceedings, is assumed in the DCF calculation. So the DCF established for Tranche 2 represents a midpoint prior to the full completion of Tranche 1 and so forth.

Figure 10: Dependable Capacity Factors, Using Renewable Energy Development Scenarios

Summer DCFs	Solar – Tracking	Solar – Fixed	Regional Wind	HVDC Wind Imports
Duke Energy (North & South Carolina)				
Tranche 1	66%	56%	-	43%
Tranche 2	51%	39%	-	35%
Tranche 3	44%	34%	-	37%
Southern Company – Georgia				
Tranche 1	61%	51%	-	-
Tranche 2	40%	30%	-	-
Tranche 3	34%	24%	-	-
Southern Company – Alabama, Florida & Mississippi				
Tranche 1	61%	53%	10%	46% / 56%[23]
Tranche 2	41%	32%	12%	23% / 29%
Tranche 3	35%	27%	12%	22% / 28%
Tennessee Valley Authority				
Tranche 1	66%	56% / 54%[24]	9%	53%
Tranche 2	56%	45% / 43%	9%	28%
Tranche 3	48%	37% / 36%	10%	22%
Tranche 4	39%	29% / 27%	11%	21%

Winter DCFs	Solar – Tracking	Solar – Fixed	Regional Wind	HVDC Wind Imports
Duke Energy (North & South Carolina)				
Tranche 1	12%	10%	-	67%
Tranche 2	6%	5%	-	58%
Tranche 3	5%	4%	-	60%
Southern Company – Georgia				
Tranche 1	23%	17%	-	-
Tranche 2	6%	4%	-	-
Tranche 3	4%	3%	-	-
Southern Company – Alabama, Florida & Mississippi				
Tranche 1	16%	11%	36%	84% / 96%[23]
Tranche 2	3%	2%	32%	37% / 45%
Tranche 3	2%	1%	28%	33% / 38%
Tennessee Valley Authority				
Tranche 1	14%	13% / 14%[24]	37%	63%
Tranche 2	8%	7% / 7%	34%	28%
Tranche 3	4%	4% / 4%	35%	16%
Tranche 4	3%	3% / 3%	34%	20%

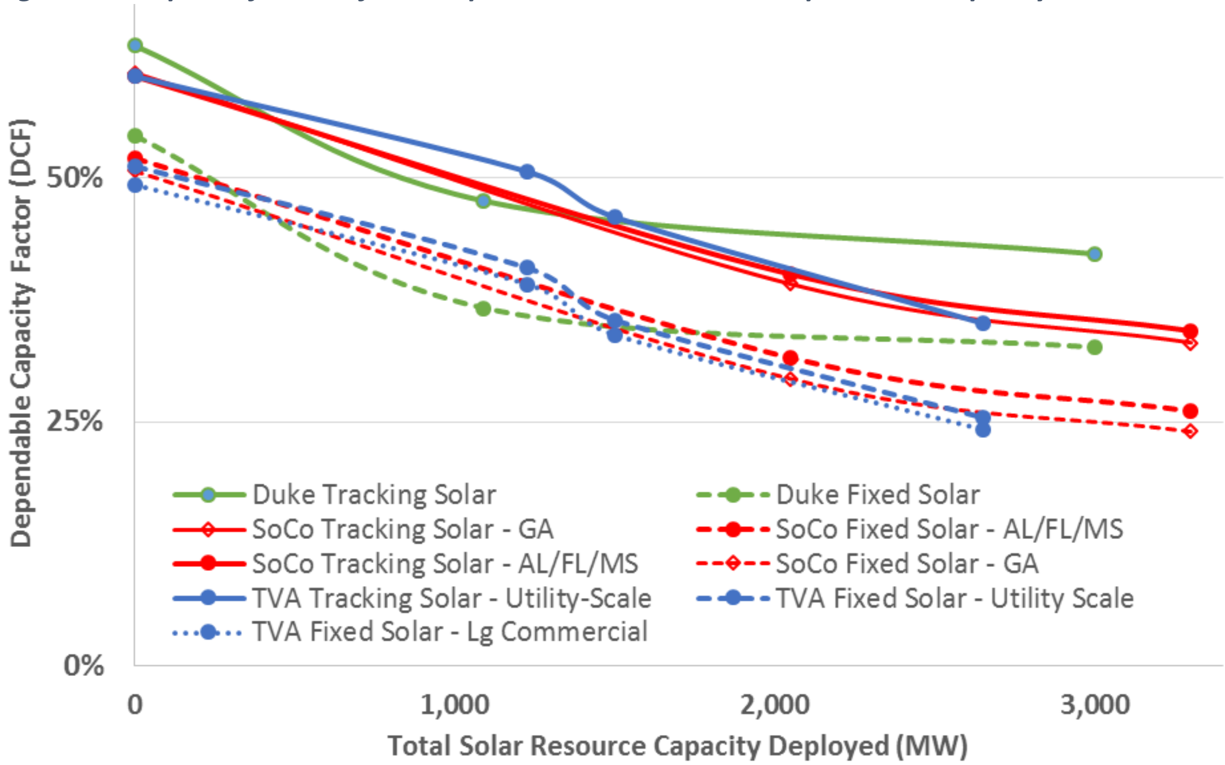
[23] Clean Line Energy's Plains & Eastern Line and Pattern Energy's Southern Cross HVDC projects reported separately. The differences are due to business model and losses imposed by intermediate AC transmission wheeling standards. The underlying wind data are identical.

A. Solar Power

Utility-scale solar power resources in the three utility service areas begin at very similar levels for both fixed mount systems (49-54% DCFs) and tracking systems (60-63%). However, as illustrated in Figure 11, at higher levels of deployment, the DCFs diverge somewhat.

The figure bears some explanation. Each point along the DCF curve represents the DCF that would be applied to the respective tranche, based on prior renewable energy development. For example, it is assumed that no renewable energy development occurs before Tranche 1 (the system load shape is assumed), so the total solar resource capacity deployed is 0 MW for purposes of calculating the Tranche 1 DCF. Then for Tranche 2, the amount of solar resource capacity deployed in Tranche 1 (see Section 6) is used to determine the seasonally modified net annual peaks for purposes of calculating the Tranche 2 DCF, as described in Step 4 (see Section 1).

Figure 11: Impact of Scale of Development on Solar Power Dependable Capacity Factors



One possible reason that the DCF curves diverge somewhat is that different amounts of wind are deployed (the curve is illustrated as a function of solar resource capacity deployment only to emphasize the primary correlation). For Duke Energy, which has the least wind power included in its scenario, the DCF values does not decrease as much as for the other two utilities. The overall finding for solar is that

[24] The first figure refers to utility-scale fixed mount solar systems, and the second figure refers to commercial-scale fixed mount solar systems. See note 16.

there is a consistent alignment of solar to system load shape across the Southeast, and the impact of solar development on DCF values decreases in a consistent manner.[25]

B. Regional Wind Power

Analysis of regional wind resources is less conclusive than for solar due to the limited data available for study. As discussed in Section 4-D, the TVA and Southern Company regional wind data are drawn from the same eight sites in the TVA service territory. (Even with identical data, differences in the DCF would be likely since the system load shapes differ.)

The main conclusion that can be drawn is that as renewable energy – mainly solar and HVDC wind imports in these scenarios – is developed, the DCF for regional wind increases, as illustrated in Figure 12. (Other relationships were examined, such as looking at wind resource capacity deployed, but the best relationship appeared to be with overall renewable energy deployment.) This occurs due to changes in the seasonally modified net annual peak, which is adjusted for renewable energy resource capacity installed during preceding tranches. As the seasonally modified net annual peak decreases, different hours now meet the 90% threshold requirement used to select the peak hours. Capacity factors for wind resources during these newly selected net peak hours are evidently significantly higher.

Figure 12: Impact of Scale of Development on Wind Power Dependable Capacity Factors[26]

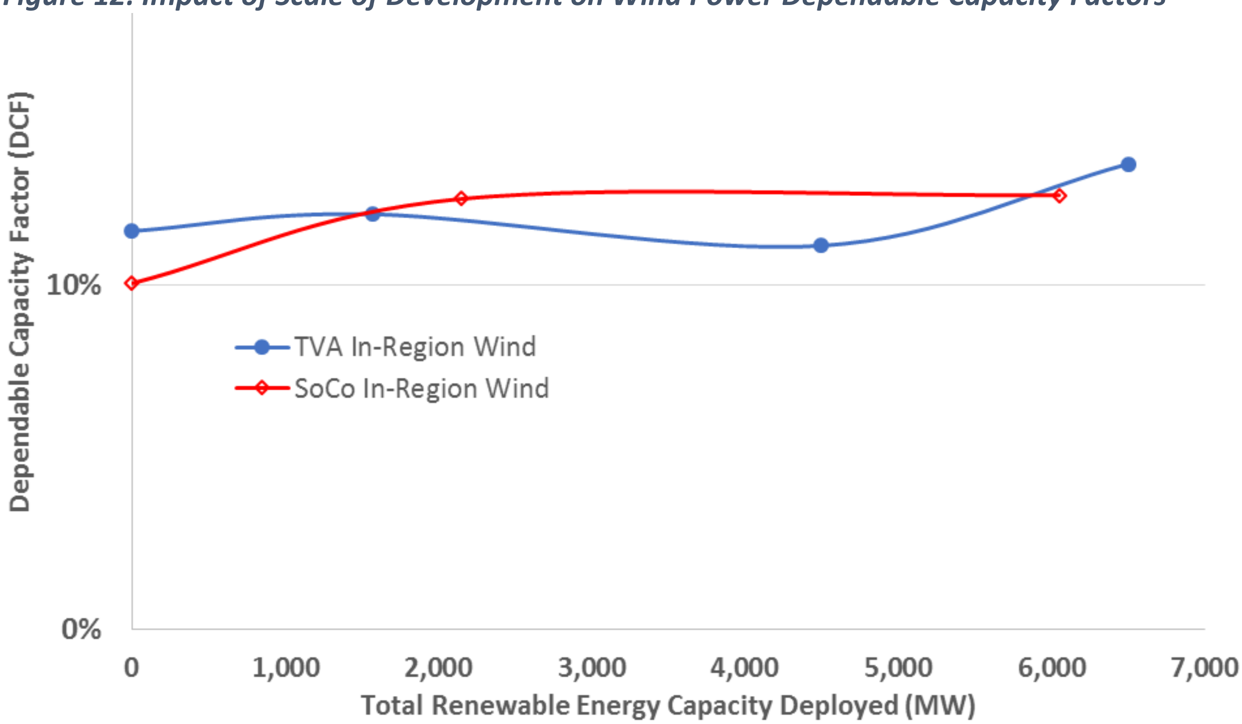


Figure 12 suggests that in-region wind DCFs increase slightly as renewable energy is deployed. However, as discussed in Section 4-D, regional wind data used in the TVA and Southern Company analyses were subsets of the same dataset from the TVA service territory. Beyond recognizing that the DCFs are similar

[25] Another impact of wind resources on solar DCFs is illustrated by the sharp, but small, drop in TVA's DCF values between Tranches 2 and 3 which is associated with by wind resource deployment in the TVA scenario.
[26] Duke Energy is not included in this figure because regional wind was not included in the development scenario for Duke Energy due to lack of available data.

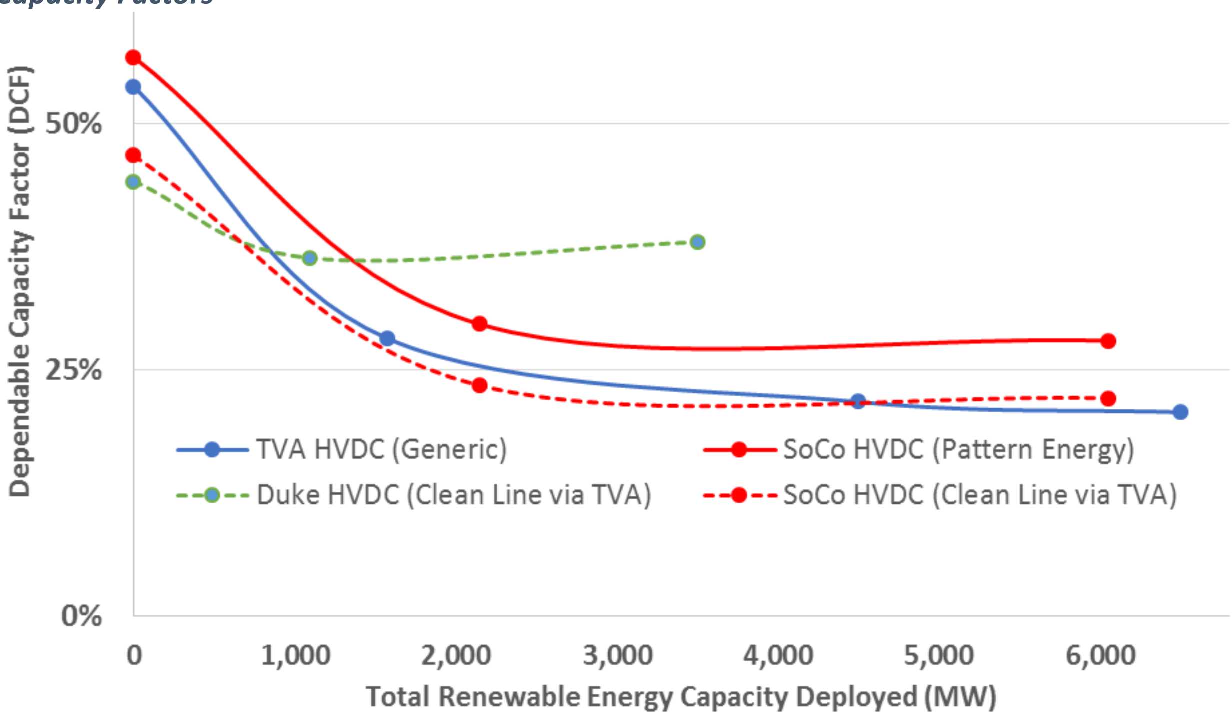
and may exhibit similar trends, the data used in this study are not adequate to reach definitive conclusions about dependable capacity factors for wind in the Southern Company service territory.

C. HVDC Imported Wind Power

In the case of HVDC imported wind power, two distinct features are illustrated (see Figure 13) that are not apparent for other resources. First, the initial introduction of primarily solar power in Tranche 1 (see Figure 9) can result in a significant decrease in the DCF for HVDC imported wind power, but as both wind and solar are added in subsequent tranches, the DCF for HVDC imported wind power remains relatively stable (most notably in contrast to solar power, see Figure 11). The second distinct feature is that this effect does not occur for Duke Energy, which could be explained by a significantly different system load shape.

In addition to those features, other differences in Figure 13 can be explained by the variation in the additional transmission losses applied to the Clean Line load shape when delivered to Southern Company and Duke Energy. Because the Clean Line project interconnects only to the TVA system, but the Pattern Energy project interconnects to both TVA and Southern Company, the Clean Line project's delivered energy and capacity are higher for the TVA system than for the more distant utility systems. As discussed in Section 4.E, the underlying wind data used to study both transmission projects are identical.

Figure 13: Impact on Scale of Development on HVDC Imported Wind Power Dependable Capacity Factors



D. Combined Analysis of Renewable Energy Resources

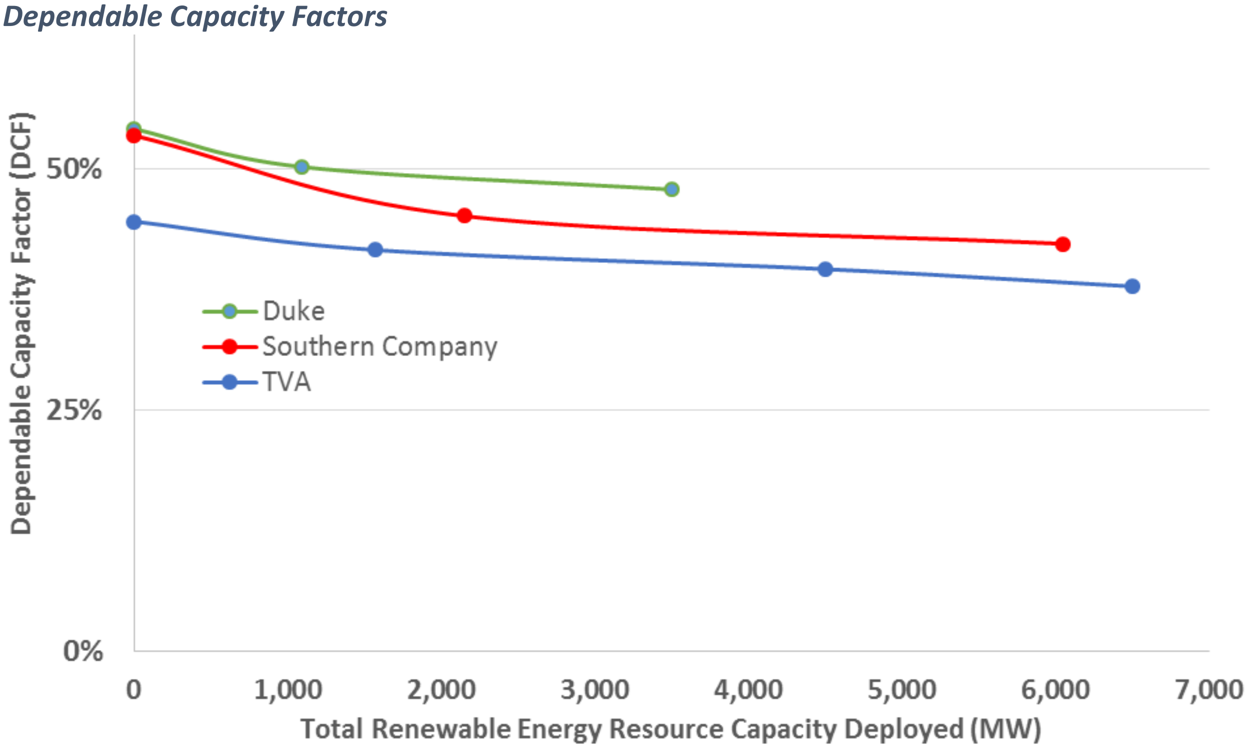
It is highly unlikely that any major utility will rely exclusively on a single renewable energy resource. As illustrated above, there can be significant interactions between the resources in terms of their dependable capacity value. For example, a utility that invests heavily in solar development for several years could find that the DCF for wind resources increases as the system peak hours are shifted into periods with relatively strong wind power production. The cliché that the whole is greater than the sum of the parts appears to apply.

One concern may be that the contribution of renewable energy resources to system dependable capacity may be highly sensitive to changes in the specific combination and deployment schedule of renewable energy resources. This does not appear to be the case, for two reasons.

First, as illustrated in Figure 14, even though there are significant differences between the utility scenarios (see Section 6), the resulting DCFs are not very different. It is clearly important to provide a reasonable forecast for the general ratio of resource technologies likely to be developed, but modest shifts in those ratios are not likely to substantially affect the total dependable capacity.

Second, the illustration also shows that as the resources are deployed, a renewable energy resources portfolio including a mix of strategies results in only a modest diminishing of the DCF as the resource mix is built out. In contrast, a utility that emphasizes a single resource could see a much steeper reduction in DCFs, as illustrated in Figure 11 and Figure 13. For planning purposes, a utility could select DCFs based on a reasonable forecast of the ratio of different technologies, conduct a capacity planning study, and then adjust the DCFs to correspond with the final plan.

Figure 14: Impact on Scale of Development on Blended Renewable Energy Resource Dependable Capacity Factors



Appendix B

Net Effective Reserve Margin Analysis: Impact of Generic Renewable Energy Resources on System Reliability

As discussed in Appendix A, utilities plan for a target reserve margin that is designed to minimize the overall cost of reliability to the customer. The System Peak Hours (SPH) method provides a measurement of an appropriate dependable capacity factor (DCF) forecast for variable energy resources for use in resource planning and other energy forecasting studies. While renewable energy resources generally perform very well during high demand periods, there may be high demand periods in which variable resources do not generate as much power as indicated by the DCF measurement. On the other hand, there will also be similar periods in which those resources generate more power than indicated by the DCF measurement.

Adding enough renewable energy to Southeastern utility systems to meet 10-20% of annual energy demand should trigger both of these counteracting effects on the level of risk that a utility has to manage. To balance these effects appropriately, a useful measurement of dependable capacity should be high enough to reflect how productive renewable energy will be during system peak hours and thus contribute to the system's capacity to serve load. Yet it should not be so high that it increases the risk that a centrally planned utility will have less capability to provide reliable service. In comparison to other averaging methods discussed briefly in Appendix A, the SPH method is designed to *avoid* misleadingly high or low results by arbitrarily excluding (or emphasizing) certain hours that are important (or unimportant) for a reliability measure.

For a utility system without significant variable renewable energy resources, the standard for determining the correct amount of system capacity is the target reserve margin. Most utilities maintain relatively up-to-date reserve margin studies, which consider the on-peak performance attributes for the existing mix of generation resources and characteristics of the utility systems' customer demand. At the target reserve margin, the loss of load probability (LOLP) is maintained at an economically optimal level.

By determining DCFs such that the target reserve margin is unaffected, the SPH method assumes a ceteris paribus approach, where the LOLP is unaffected by any changes to the characteristics of the generation mix or customer demand other than the introduction of renewable energy resources. This is similar to the Effective Load Carrying Capability (ELCC) method (described in Appendix A) which holds all other aspects of the system constant, while calculating the difference in loads that can be reliably served by a generation system "with" and "without" a defined level of renewable energy resources.[1]

In order to quantitatively demonstrate how effectively the SPH method balances the reliability effects of variable resources, a Net Effective Reserve Margin (NERM) is calculated to illustrate the effect of renewable energy on system reserves. Like the ratio method highlighted in Figure 5, the NERM technique is intended to act as a quantitative test to illustrate whether a proposed DCF is balanced and the capacity is "right."

[1] MISO, *Planning Year 2014-2015 Wind Capacity Credit* (December 2013).

As discussed in the main report, even if the number of hours with higher reliability risks is very low, it would be reasonable to be concerned that there could be specific hours in which a system that depends on high levels of renewable energy might be at greater reliability risk due to highly unusual circumstances. By considering aggressive, but realistic scenarios of renewable energy development in the context of actual system conditions for over a decade, the likelihood that an extreme event has been overlooked has been minimized. The NERM technique provides a finer resolution measurement of the changes in risks that the utility should plan to manage.

1. Relationship Between a Target Reserve Margin and a Dependable Capacity Factor

As discussed in Appendix A, utilities plan for a target reserve margin that is designed to minimize the overall cost of reliability to the customer. The target reserve margin is an optimal value: insufficient reserves put customers at risk of either system failures or expensive short-term market purchases, but excessive reserves guarantees that customers will pay for capacity that may not be sufficiently utilized to justify the cost. Most target reserve margins are set at a level that the utility believes will demonstrate achievement of an industry accepted reliability standard of 1 day in 10 years expected loss of load (LOLE).

The more difficult methods to measure DCFs use a loss of load probability (LOLP) calculation to apply the utility's reliability standard. While not explicitly relying on LOLP data, the SPH method is designed to track the LOLP concept closely by assuming a ceteris paribus approach, where the LOLP is unaffected by any changes to the characteristics of the generation mix or customer demand that occur other than the introduction of renewable energy resources. This is similar to the ELCC method, which holds all other aspects of the system constant, while calculating the difference in loads that can be reliably served by a generation system "with" and "without" a defined level of renewable energy resources.[2]

To implement the ELCC method or generate LOLP data, the utility must utilize robust distributions of load, weather, and unity performance uncertainty, including all production cost variables and unit constraints.[3] For example, MISO's most recent wind capacity report determined the "capacity credit at 176 individual wind [Commercial Pricing Nodes]," using a model that incorporates "historic operation performance data for all conventional unit types in the MISO system."[4] As with a robust reserve margin study, such a comprehensive study represents a significant resource commitment by a utility towards effective planning and would not likely be conducted frequently. Exploring a large number of alternative scenarios in an ELCC study effectively requires streamlined simulation practices.[5]

The key to the usefulness of the ELCC method is its ability to isolate the reliability effects for the resource in question from those of other resources. But utilities routinely plan for future development of generation resources without requiring a new reserve margin study (or an ELCC study) because utility integrated resource plans are conceptual guides to future investment choices. Detailed reserve margin

[2] MISO, *Planning Year 2014-2015 Wind Capacity Credit* (December 2013).
[3] Carden, K, *Modeling Resource Adequacy Impacts of Integrating Intermittent Resources*, Astrape Consulting (February 2013).
[4] MISO, *Planning Year 2014-2015 Wind Capacity Credit* (December 2013), p. 4, 7.
[5] Pfeifenberger, JP et al, *Resource Adequacy Requirements: Reliability and Economic Implications*, prepared for the Federal Energy Regulatory Commission by The Brattle Group and Astrape Consulting (September 2013), p. 18.

or ELCC studies typically do not need to be updated frequently unless there are substantial system changes or other financial considerations such as capacity market auctions.

Ultimately, the purpose of establishing a valid DCF for variable resources is to ensure that resource plans developed using such factors are unlikely to affect the utility's reliability to such a degree that the results of a reserve margin study would change significantly. By measuring the DCF as the average capacity factor during peak hours, and by ensuring that those peak hours are the peak hours which would occur if a resource was deployed at substantial scale, the SPH method should closely track measurements made with LOLP data such as the ELCC method.

2. Net Effective Reserve Margin (NERM) Technique

Utilities typically establish target reserve margins such that "the cost of additional reserves plus the cost of reliability events to the customers [are] minimized."[6] It follows, therefore, that increasing or decreasing the reserve margin would result in higher costs to the customer.

To illustrate the effect of imposing these higher costs on the customer, Figure 1 contrasts the effective reserves during each hour of a thirteen-year period for the Tennessee Valley Authority (TVA). In this illustration, the effective reserves are defined as follows:

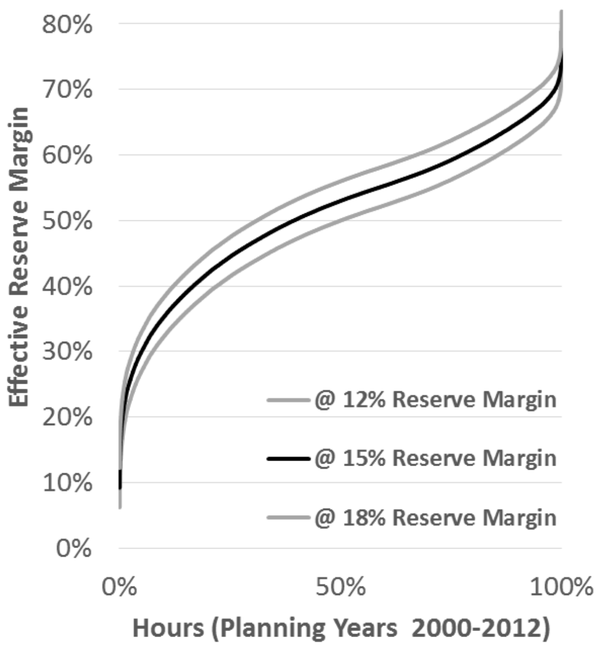
- RM = Reserve Margin
- Effective reserves (Hour n) = (1 + RM) x Forecast Annual Peak – Load (Hour n)
- RM_E = Effective reserve margin (Hour n) = Effective reserves (Hour n) / Forecast Annual Peak

This effective reserve margin curve can be viewed as the inverse of a load duration curve, with the multi-year dataset normalized to the forecasted annual peak.

The illustration also shows two hypothetical alternatives to TVA's 15% reserve margin: one in which TVA reduced its reserves to only 12%, and another in which it increased its reserves to 18%. It follows from the definition of the target reserve margin that if TVA used either a 12% or an 18% reserve margin, costs to the customer would *not* be minimized.

[6] TVA 2011 IRP

Figure 1: Effective Reserve Margin for Tennessee Valley Authority for 12%, 15% and 18% Target Reserve Margins



The NERM technique relies on this deduction to identify that any resource change which results in the effective reserve margin departing from the ideal 15% curve as having the potential to increase costs to the customer. Departures *above* the 15% curve reduce the LOLP for those hours, but also increase carrying costs for unnecessary capacity, and may be offset by lower costs in other respects (e.g., reduced fuel costs). Departures *below* the 15% curve increase the LOLP, and represent the costs of potential reliability events to the customer. (To quantify the net effect, it would be necessary to apply utility cost data and its system LOLP, but then an ELCC measurement would be practical and preferred.) If the net effect on the LOLP is an increase, the costs of potential reliability events to the customer could be offset through reliability-enhancing investments. This analysis does not study such investments but rather seeks to illustrate whether such a concern is even worth considering.

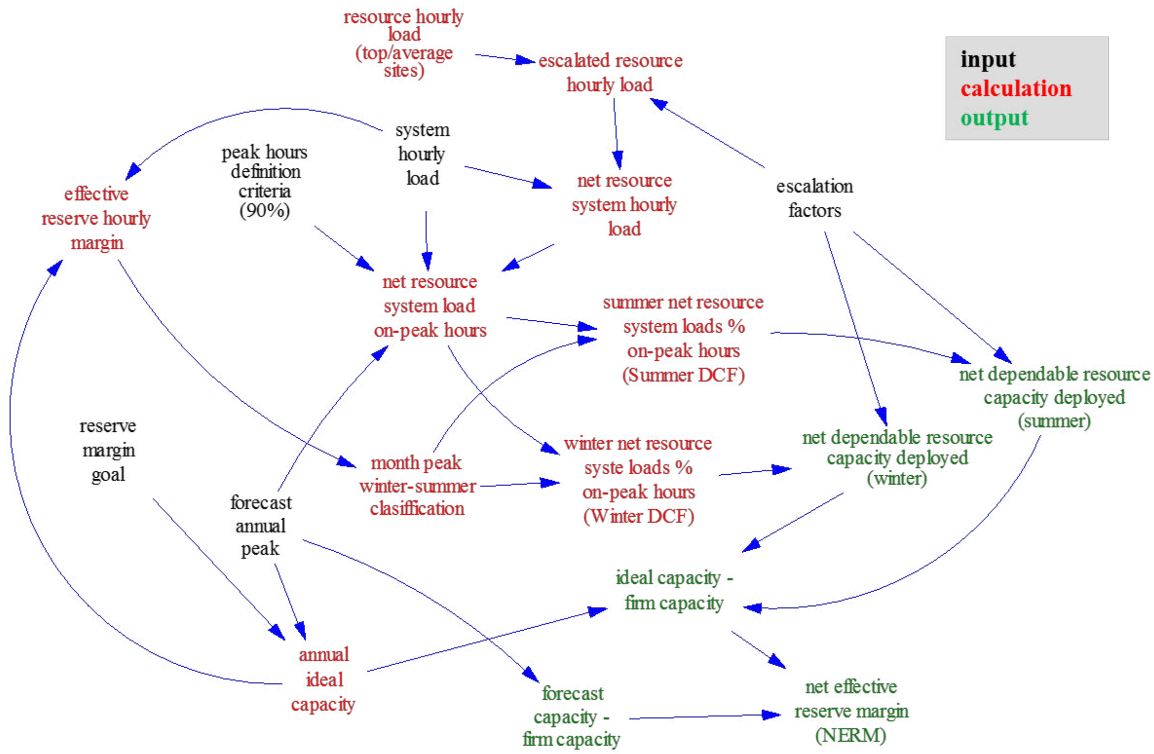
The effective reserve margin considers the utility system in its base configuration, a configuration that should be reasonably similar to the utility system studied to establish the target reserve margin. In order to study a utility system modified to include a substantial amount of variable resource deployment, the *net* effective reserve margin is calculated. In other words, the NERM technique is a way to estimate the impact of non-dispatchable energy resources on the dispatchable reserves required to maintain reliability. The assumption is that the LOLP curve for the net load is the same as the LOLP curve for the base system load, which seems reasonable as the system serving the net load is likely to be very similar to the base system.

The net effective reserve margin calculation is a modified version of the effective reserve margin, and is illustrated in casual loop diagram form in Figure 2. The NERM curve is associated with a specific scenario of renewable energy deployment with a nameplate capacity (NC) and a net dependable capacity (NDC) (calculated using the SPH method) for summer and winter.[7] The hourly capacity factor (CF) is obtained from the resource data files described in Appendix A.

- $NDC_S = DCF_S \times NC$
- Net effective reserves (Hour n) = ((1 + RM) x Forecast Annual Peak - NDC_S) - (Load(Hour n) - NC x CF(Hour n))
- Net RM_E = Net effective reserves (Hour n) / (Forecast Annual Peak - NDC_S)
- For winter, substitute $NDC_W = DCF_W \times NC$

The resulting NERM curves for specific resource deployment scenarios are presented for TVA, Duke and Southern Company in the following sections. First, the results of the most aggressive level of renewable energy scenarios tested for this project are reviewed. Next, individual resource studies are presented utilizing hypothetical 4 gigawatt (GW) development levels for individual technologies. It is unlikely that any of these utilities would invest in 4 GW of a single variable resource technology. Because the blended resource development scenarios demonstrate that DCFs are affected by the degree to which all variable resources are developed, it would be unreasonable to rely on these individual resource studies for planning purposes. However, it is interesting to compare the various resources and note differences in the impact of each resource on net effective reserve margins.

Figure 2: Net Effective Reserve Margin (NERM) Technique Calculations

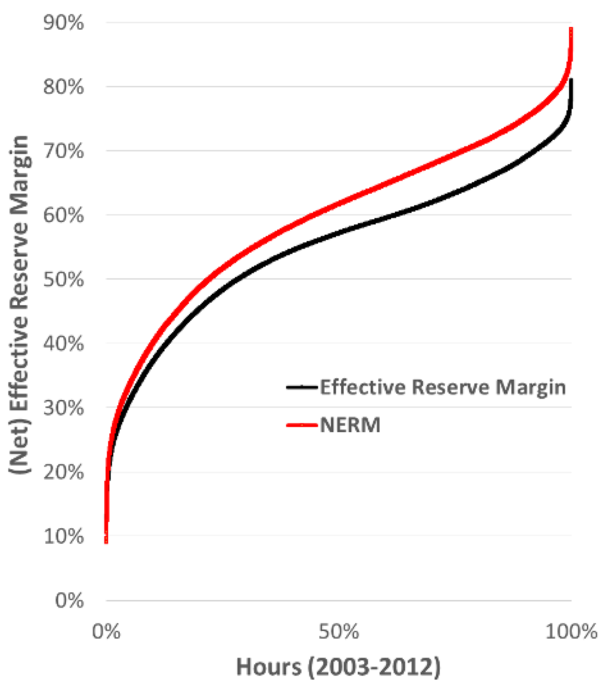


[7] The planning year is defined as beginning June 1. Winter months are November through March.

3. SPH Method Validation Using Aggressive Renewable Energy Development Scenarios

The overall impact of substantial renewable energy resources on the effective reserve margins of the utilities studied in this analysis is to increase hourly reserve levels during the vast majority of operating hours. For example, renewable energy with a nameplate capacity of 7.3 GW on the Southern Company system would reduce dispatchable generation requirements by about 3.1 GW. The 7.3 GW deployment represents roughly 20% of forecast annual peak loads for the Southern Company system, and is rated at an average DCF of 42.5%. Even with dispatchable capacity requirements reduced by roughly 10%, Figure 3 illustrates how effective hourly reserves (dispatchable generation plus hourly renewable energy generation) generally exceed the effective reserve margin. This effect is by design, the SPH method is designed to identify the level of generation that can be relied upon, but of course hourly generation often exceeds the dependable capacity.

Figure 3: Net Effective Reserve Margin for Southern Company, 7.3 GW Renewable Energy Scenario



Similar NERM curves can be produced for individual resource development scenarios, and for all utilities studied in this analysis. Any impression that well planned renewable energy deployments will lead to frequent shortfalls in available resources is simply unsupported by available data.

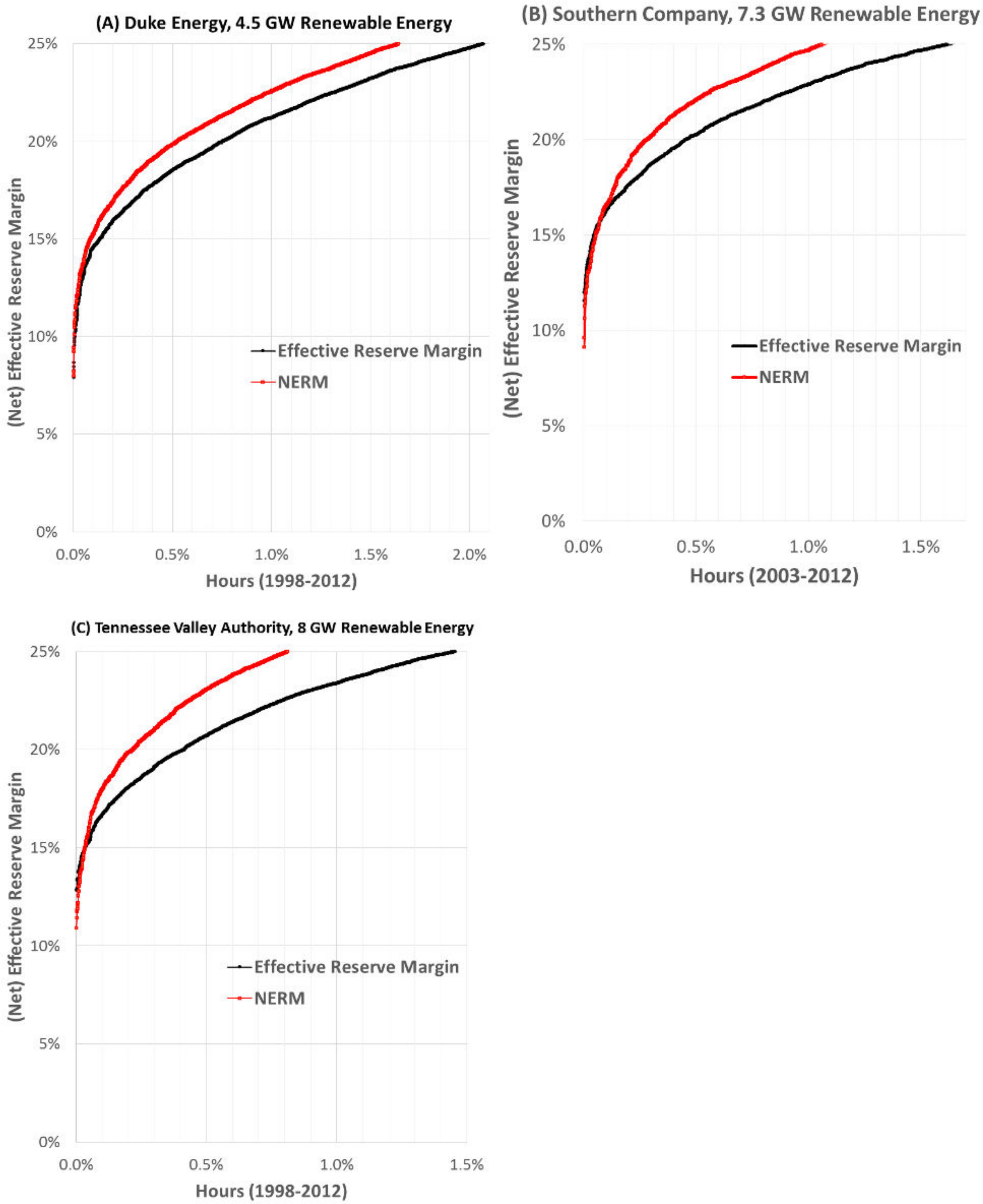
Of course, from a reliability perspective, the focus is not on the vast majority of hours in which the system has more than ample available resources, but on those few hours in which the system is potentially challenged to meet customer demand. As illustrated in Figure 4, the NERM curve follows the effective reserve margin curve closely even during the most challenging 0.1% of hours.

- For Duke Energy (North and South Carolina), there were no hours in 15 years with reduced reserve margin relative to the baseline.[8]
- For Southern Company, renewable energy deployment resulted in 6 hours in 10 years with reduced reserve margin relative to the base case. The increase was less than 1% for all but 2 of the 6 hours.
- For Tennessee Valley Authority, renewable energy deployment resulted in 11 hours in 15 years with reduced reserve margin relative to the base case. The increase was less than 1% for all but 4 of the 11 hours.

The NERM curve also exhibits the benefit of substantially fewer hours with a NERM of less than 25% relative to the base effective reserve margin. These effects are quantified and elaborated on below.

[8] The effective reserve margin curve for Duke Energy illustrates that the number of hours with an effective reserve margin for the base system is roughly 35% higher than for Southern Company or TVA. This may suggest that the reserve margins for Duke Energy carry more risk and less cost than those of Southern Company and TVA.

Figure 4: Net Effective Reserve Margin for (A) Duke Energy, (B) Southern Company and (C) Tennessee Valley Authority with Substantial Renewable Energy Development



The findings illustrated above suggest two ways in which the LOLP may be affected by substantial deployment of renewable energy resources. First, for a few hours captured in the dataset, the LOLP is evidently increased (an adverse effect). When the net effective reserve margin curve dips significantly below the effective reserve margin curve, the data indicate an increased likelihood of a reliability incident.

However, counteracting that effect is the large reduction in the number of hours with a low net effective reserve margin (a positive effect). It is not possible to quantitatively demonstrate which effect is larger.[9] It is statistically more probable, of course, that the event would occur during an hour with a lower effective reserve margin because quite obviously the utility system has less tolerance for generator outages at that level. So when dealing with an increase in probabilities on the one hand, and a decrease in the number of hours with significant probabilities on the other, a quantitative solution can only be calculated in an ELCC study framework. Nonetheless, it is possible to arrive at some quantitative observations.

Two quantities are calculated to represent these competing effects.

- **Higher risk hours**: The number of hours that would need to be removed from the net effective reserve margin curve in order for that curve to be substantially identical to or in excess of the effective reserve margin curve.[10]
- **Reliability ensured hours**: The reduction in the number of hours with a significant probability of reliability incidents.[11]

As illustrated in Figure 5, the ratio of higher risk hours to reliability ensured hours is 1:76 or less, with a clearly positive impact appearing to occur on the Duke Energy system on which no higher risk hours result from setting capacity values based on the SPH method.

Figure 5: Impact of Substantial Renewable Energy Development Scenarios on Reliability

	Higher Risk Hours	Reliability Ensured Hours	Ratio
Duke Energy (North and South Carolina)	0.0 % (0)	0.734 % (558)	0:100
Southern Company	0.007 % (6)	0.549 % (481)	1:80
Tennessee Valley Authority	0.008 % (11)	0.639 % (840)	1:76

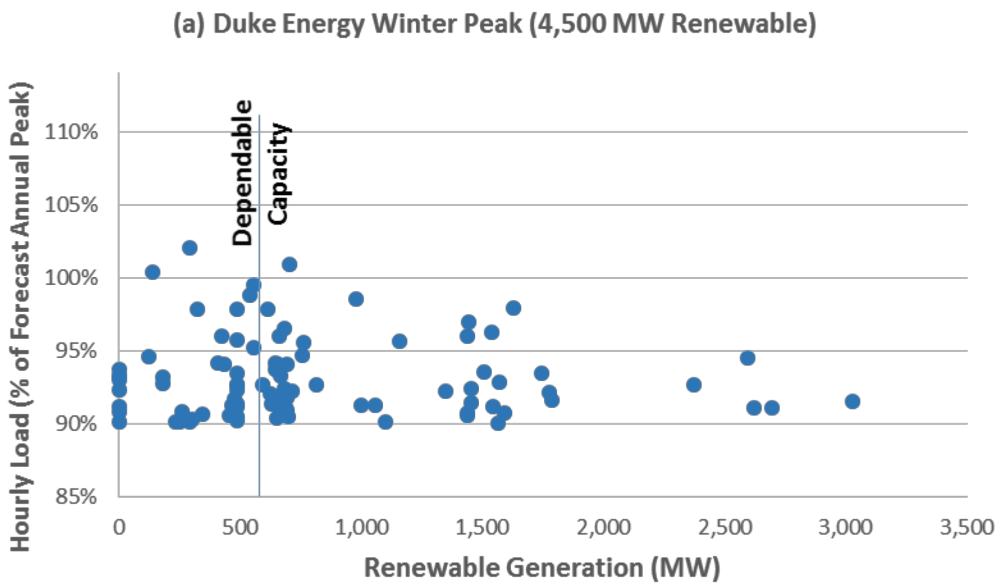
Thus, NERM technique illustrates that the SPH method can support planning outcomes that do not adversely affect the level of reserves on utility systems on a daily or hourly basis. Some hours are more reliable, some hours are less reliable. Concentrating on lower reliability in some particular hour would ignore the improvements in many other hours. In other words, the SPH method is an effective tool for

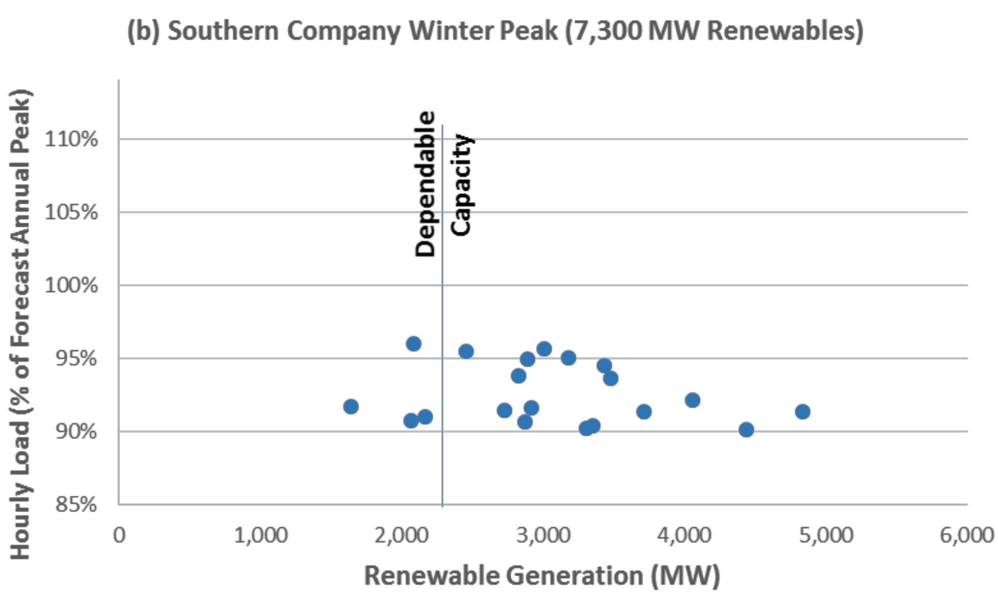
[9] The underlying methods of a target reserve margin study involve stochastic evaluation of probabilities. For example, in a random draw of circumstances, the utility may not experience a reliability event during an hour with an effective reserve margin of 10%, but might experience a reliability event during an hour with an effective reserve margin of 20%.
[10] In other words, the number of hours in which the utility might consider taking additional measures to ensure no added risk of a reliability incident.
[11] For this project, the number of hours was compared up to the 25% (net) effective reserve margin level, consistent with the SHP method use of a 90% below forecast annual peak plus a 15% target reserve margin.

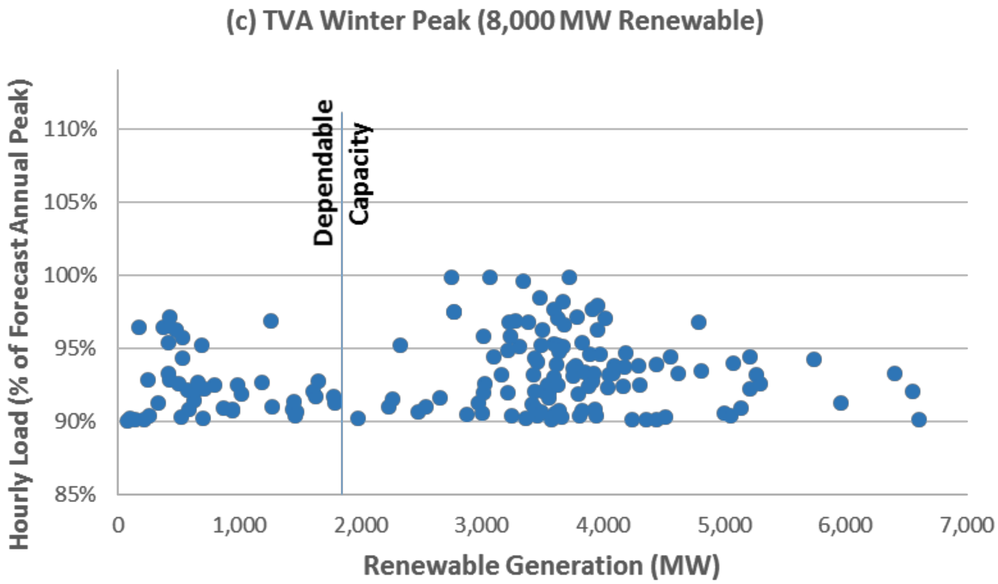
ensuring that renewable energy can be studied in a resource planning model without compromising reliability.

These reliability effects were also examined for winter peaking concerns, as discussed in Section 4 of the report. In Figure 6, the three utilities are analyzed by estimating renewable generation output during hours in which winter loads exceed 95% of the annual peak forecast by the utility for the corresponding planning year.

Figure 6: Renewable Generation During Winter Peak Hours for (A) Duke Energy, (B) Southern Company and (C) Tennessee Valley Authority







4. Individual Resource Studies of SPH Method Using 4 GW Development Levels

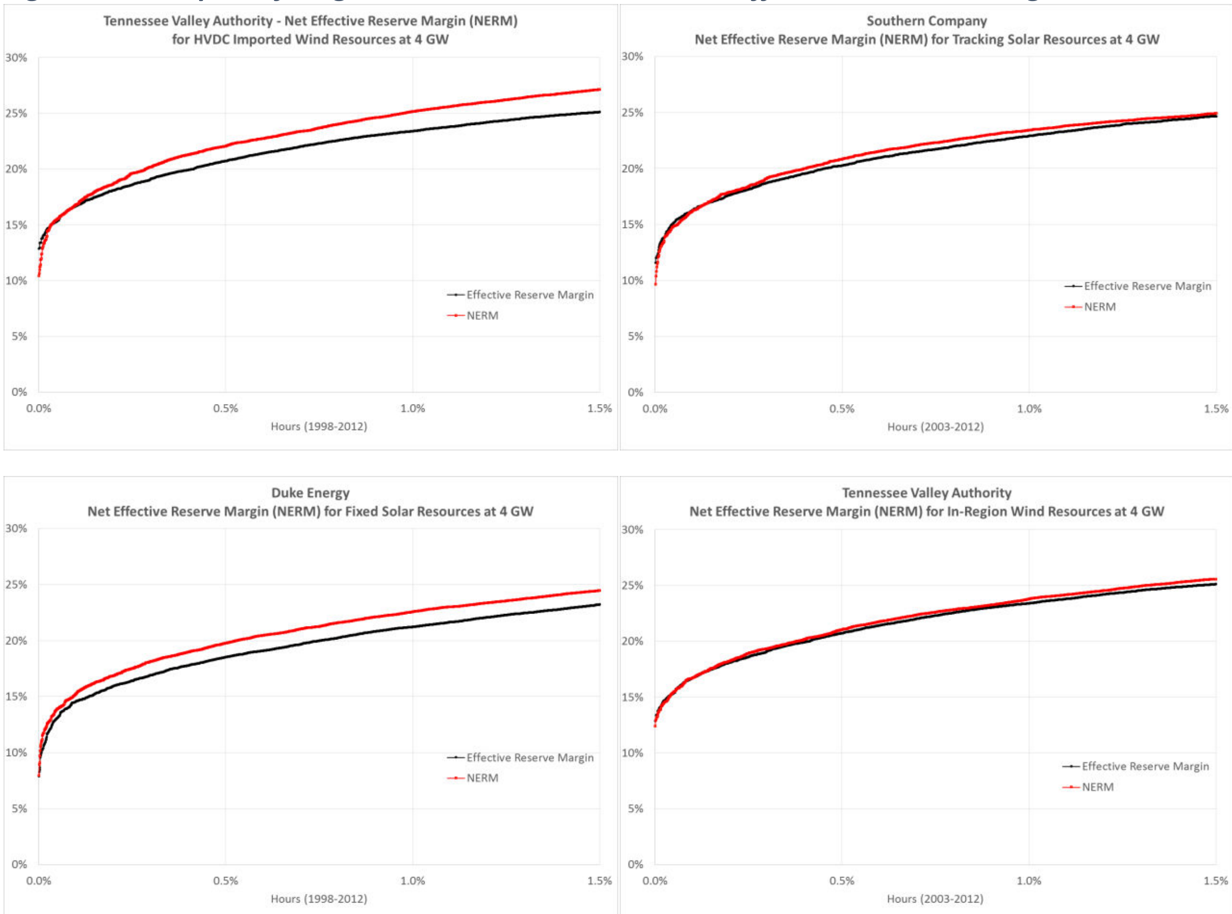
Although several utilities have published estimates for DCFs (or equivalent terms) at current system levels, none has yet published a projected value based on substantial development of renewable energy. As illustrated in Figure 4 of the main report, studies by a number of utilities have demonstrated that the dependable capacity for variable resources decreases with significant increases in resource deployment. Evidently, the relationship varies by resource, utility and planning assumptions (such as deployment of other renewable energy resources).

It is unlikely that any Southeastern utility would invest in 4 GW of a single variable resource technology. Even if solar is emphasized by some utilities, a variety of technologies and interconnection types would occur. Each combination of technology and interconnection type can result in a different DCF value. As the blended resource development scenarios demonstrate, DCFs are affected by the degree to which all variable resources are developed. For these reasons, it would be unreasonable to rely on these individual resource studies for planning purposes.

Nonetheless, it is interesting to compare the various resources and note differences in the impact of each resource on net effective reserve margins. In combination with the findings related to blended resource scenarios, utility planners can use individual resource studies to inform their planning decisions. Accordingly, hypothetical 4 gigawatt (GW) development levels for individual technologies are provided for review. As illustrated in Figure 7,[12] using the SPH method to calculate DCFs for individual resources does not result in an obvious increase in risk of resource inadequacy, even at 4 GW of nameplate resource deployment.

[12] One example is provided for each of the four technologies studied. Graphs for other utilities studied look similar for each resource.

Figure 7: Examples of Single Resource Scenarios on Net Effective Reserve Margin



Appendix C

Impact of Renewable Energy on the Ramping of Conventional Generation Plants in the Southeast

To maintain reliability, utilities must continuously match the demand for electricity with supply on a second-by-second basis. Much of this is automated, but utilities must plan for and actively control power plant units to increase or decrease generation in response to changes in demand. As renewables are deployed on the grid, a portion of the utility's supply capacity is represented by variable generation resources with more limited (or nonexistent) control capabilities.

Net load curves are used to illustrate the utility's challenge to direct controllable resources to match both variable demand and variable supply. A net load is calculated by subtracting the forecasted electricity production from variable generation resources, wind and solar, from the forecasted load.

One specific concern is that utilities will face challenges of supplying large amounts of power within a short time period to replace the electricity lost by solar power as the sun sets. A more general concern is that utilities will find it more costly or risky to meet operating challenges associated with variable renewable energy resources. As discussed in the main paper, a substantial problem of this nature is unlikely to appear in the Southeast.

Two analyses were conducted to reach this finding. In the first analysis (see Section 1), two historical episodes were selected from each utility dataset to illustrate extreme operating conditions. One episode was selected to represent a system peaking event, identifying a multi-day period with peaks in excess of the utility's forecast annual peak.[1] The second episode was selected to represent a low load event with high renewable energy generation, identifying a period in which renewable energy is at its highest share of total electric generation.

In the second analysis (see Section 2), the entire data set was examined statistically for individual renewable resources (e.g., in-region wind), as well as a scenario of combined renewable resources. Ramp rates were calculated over 1-hour increments.[2] This provided a broad view, considering hours in which renewable energy improved system ramp rates as well as those in which ramp rates became more challenging.

1. Case Studies on Episodes of Extreme Operating Conditions

Case studies of extreme operating conditions are often used to demonstrate the impact of variable renewable energy on utility systems. The two most extreme conditions would be system peaking events and low load events (associated with high renewables penetration).

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[1] Each of the six case study episodes span almost the full range of potential renewable energy generation. The Southern Company and TVA scenarios include substantial amounts of both solar and wind resources; average renewable generation capacity factors are about 40% in system peaking events and 50% in low load events. Because the Duke Energy analysis includes mostly solar resources, the average renewable generation capacity factors in the system peaking event and the low load event are lower, about 35%.

[2] Three hour ramp rates were also calculated for a portion of the analysis, but the results were not sufficiently different from the one hour ramp rate studies to suggest any benefit to more extensive study.

One example of each episode was selected for each utility. Coincidentally, for all three utilities, the August 7-10, 2007 episode was selected as a highly challenging peaking event. For the low load event with high renewable energy generation, the most challenging episodes for each utility occurred in April, but on different dates in 2011 and 2012. Net load curves are provided for each episode, at varying levels of renewable energy (including both wind and solar resources in each scenario, as described in Appendix A.)

For each episode, data are summarized (see Figure 1 and Figure 2) for each of the utilities in the following categories.

- System peak – the highest demand on the (net) load curve for the episode
- Swing – the total ramp up from minimum (net) load to maximum (net) load; all values are provided on the net load curve graphs, with the minimum and maximum values summarized in the figures below
- Ramp – the average ramp rate over the ramping period (e.g., swing divided by hours)

These system level case studies do not consider market power imports or exports, nor do they include consideration of localized issues that might require dispatch or transmission contingency planning. Figures 3, 4, 5, 6, 7 and 8, illustrate the load impacts that varying levels of renewable generation would have on each utility under a summer peaking event versus springtime low-load event.

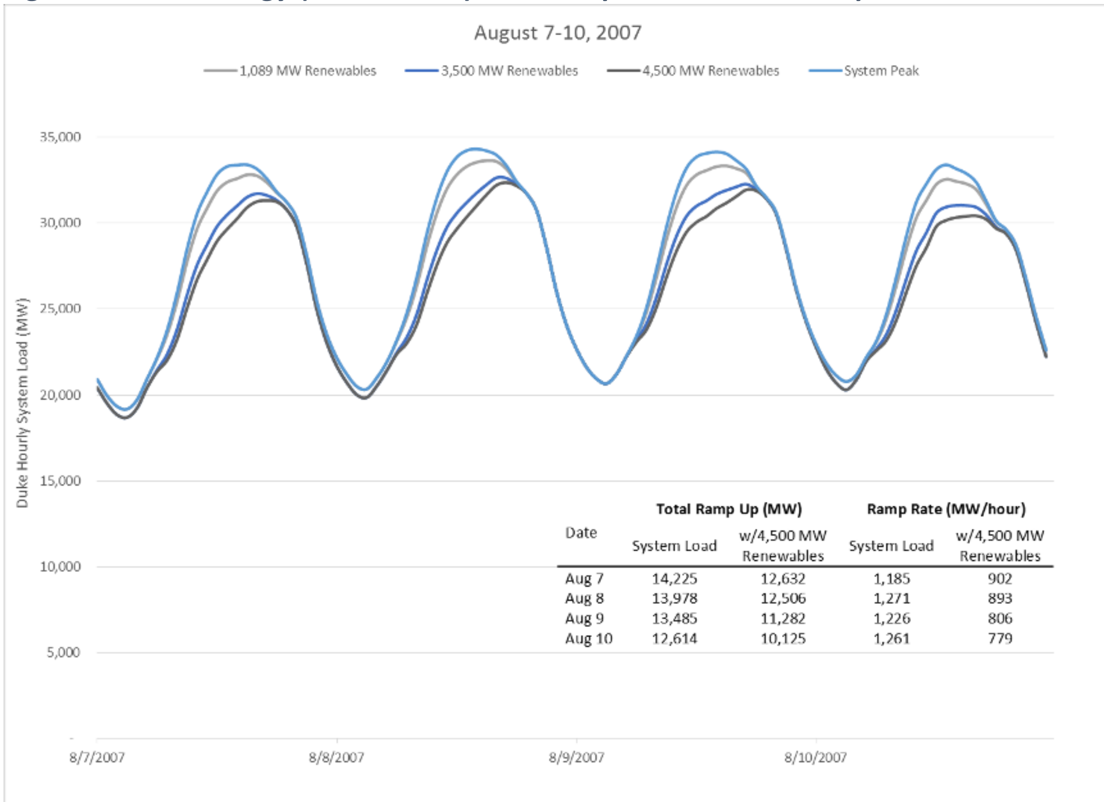
Figure 1: System Peaking Event Case Studies

	System Peak (MW)	**Minimum Swing** (MW)	**Maximum Swing** (MW)	**Maximum Ramp** (MW/hr)
Duke Energy (North and South Carolina)	34,323	12,614	14,225	1,271
Southern Company	36,029	13,100	13,674	1,140
Tennessee Valley Authority	33,315	11,681	12,912	1,076
High Renewable Generation Scenario				
Duke Energy (North and South Carolina)	32,223	10,125	12,632	902
Southern Company	34,217	11,242	14,447	1,032
Tennessee Valley Authority	31,034	11,335	14,180	1,013

Figure 2: Springtime Low Load / High Renewables Event Case Studies

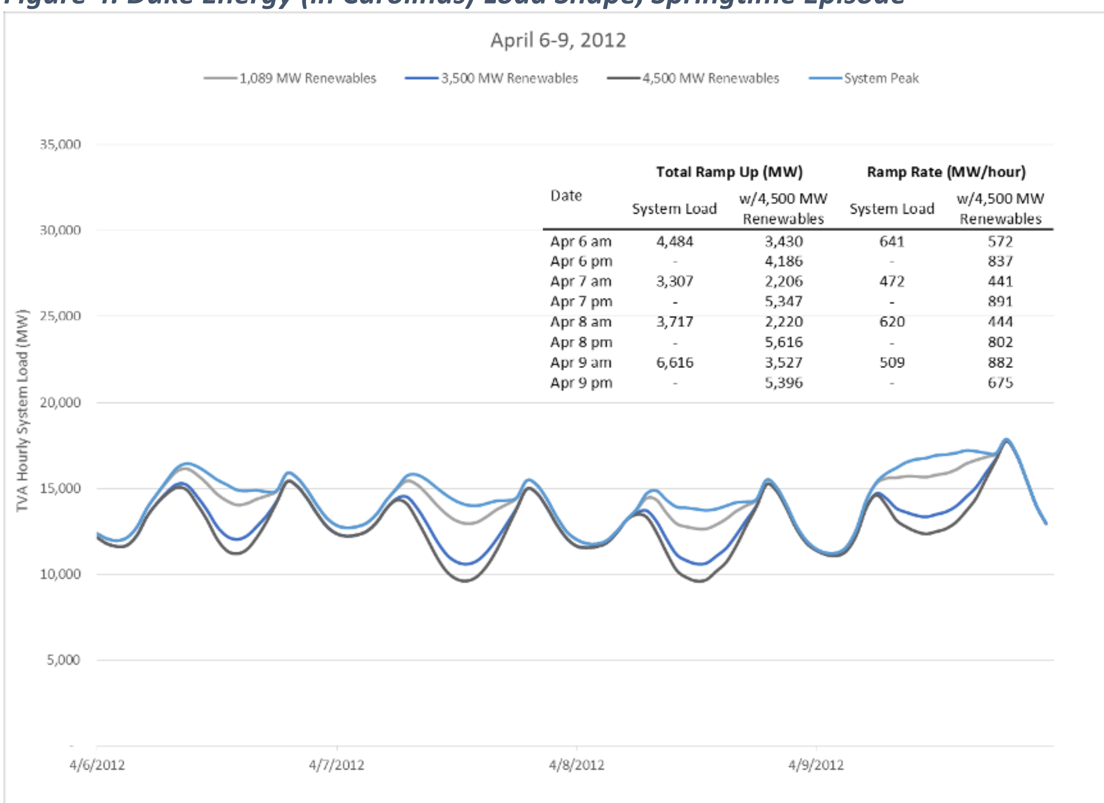
	System Peak (MW)	**Minimum Swing** (MW)	**Maximum Swing** (MW)	**Maximum Ramp** (MW/hr)
Duke Energy (North and South Carolina)	17,857	3,307	6,616	641
Southern Company	21,062	3,405	7,702	804
Tennessee Valley Authority	17,975	4,230	6,446	645
High Renewable Generation Scenario				
Duke Energy (North and South Carolina)	17,857	2,220	5,616	891
Southern Company	18,458	4,897	7,671	979
Tennessee Valley Authority	14,432	3,229	7,395	975

Figure 3: Duke Energy (in Carolinas) Load Shape, Summer Peak Episode



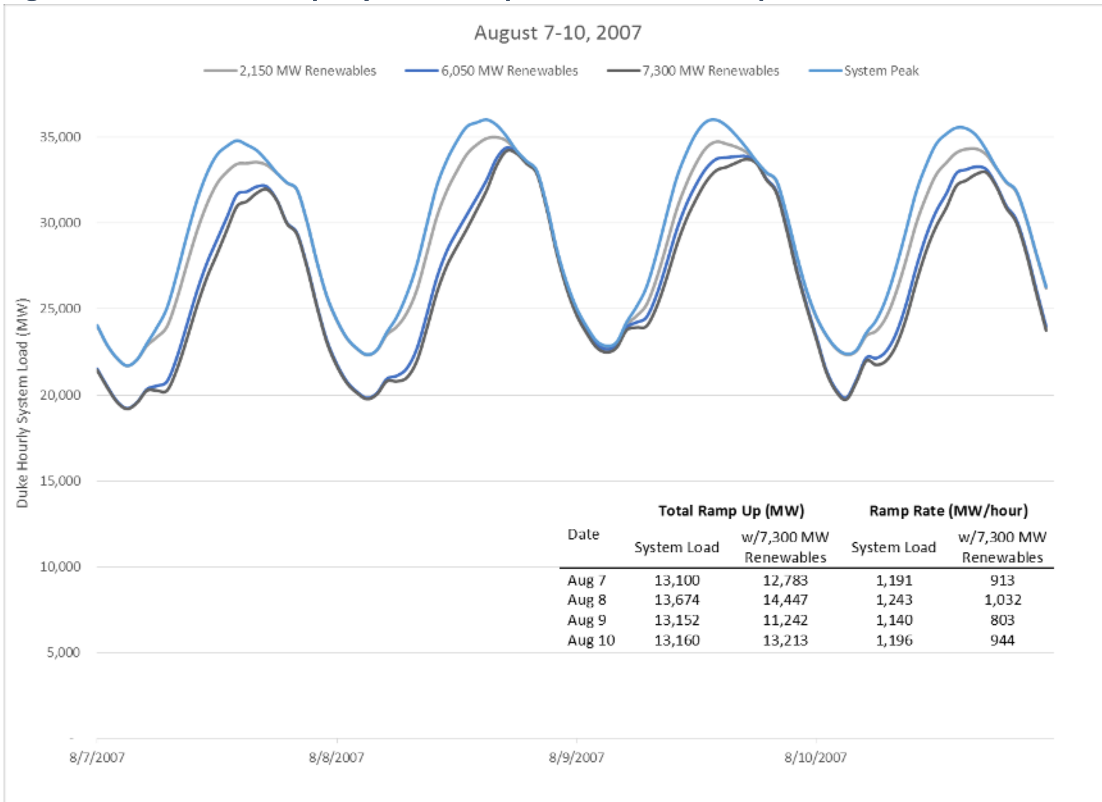
Date	Total Ramp Up (MW) System Load	Total Ramp Up (MW) w/4,500 MW Renewables	Ramp Rate (MW/hour) System Load	Ramp Rate (MW/hour) w/4,500 MW Renewables
Aug 7	14,225	12,632	1,185	902
Aug 8	13,978	12,506	1,271	893
Aug 9	13,485	11,282	1,226	806
Aug 10	12,614	10,125	1,261	779

Figure 4: Duke Energy (in Carolinas) Load Shape, Springtime Episode



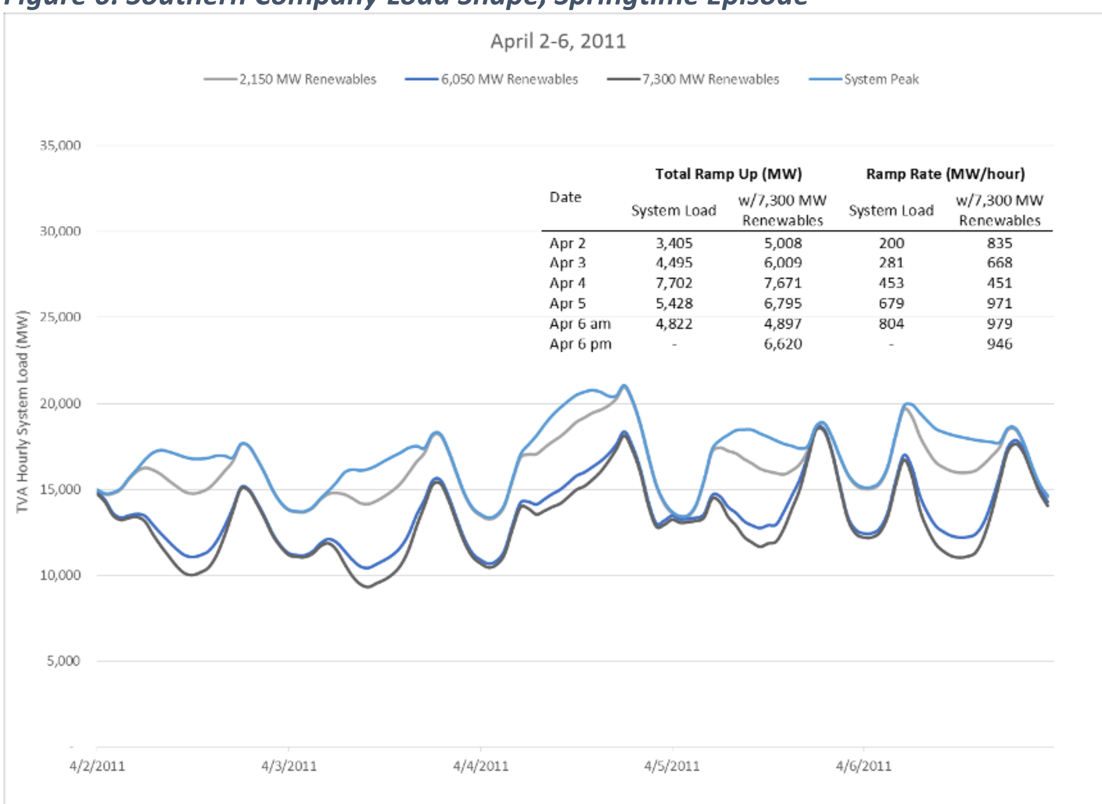
Date	Total Ramp Up (MW) System Load	Total Ramp Up (MW) w/4,500 MW Renewables	Ramp Rate (MW/hour) System Load	Ramp Rate (MW/hour) w/4,500 MW Renewables
Apr 6 am	4,484	3,430	641	572
Apr 6 pm	-	4,186	-	837
Apr 7 am	3,307	2,206	472	441
Apr 7 pm	-	5,347	-	891
Apr 8 am	3,717	2,220	620	444
Apr 8 pm	-	5,616	-	802
Apr 9 am	6,616	3,527	509	882
Apr 9 pm	-	5,396	-	675

Figure 5: Southern Company Load Shape, Summer Peak Episode



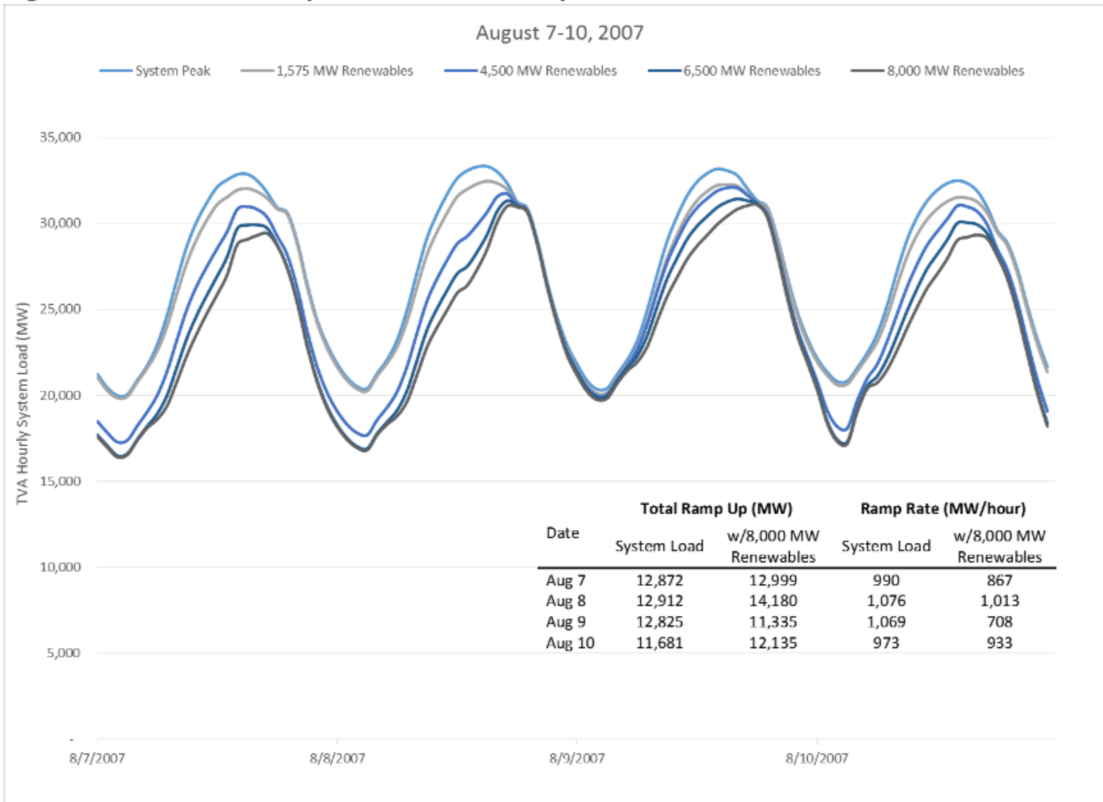
Date	Total Ramp Up (MW)		Ramp Rate (MW/hour)	
	System Load	w/7,300 MW Renewables	System Load	w/7,300 MW Renewables
Aug 7	13,100	12,783	1,191	913
Aug 8	13,674	14,447	1,243	1,032
Aug 9	13,152	11,242	1,140	803
Aug 10	13,160	13,213	1,196	944

Figure 6: Southern Company Load Shape, Springtime Episode



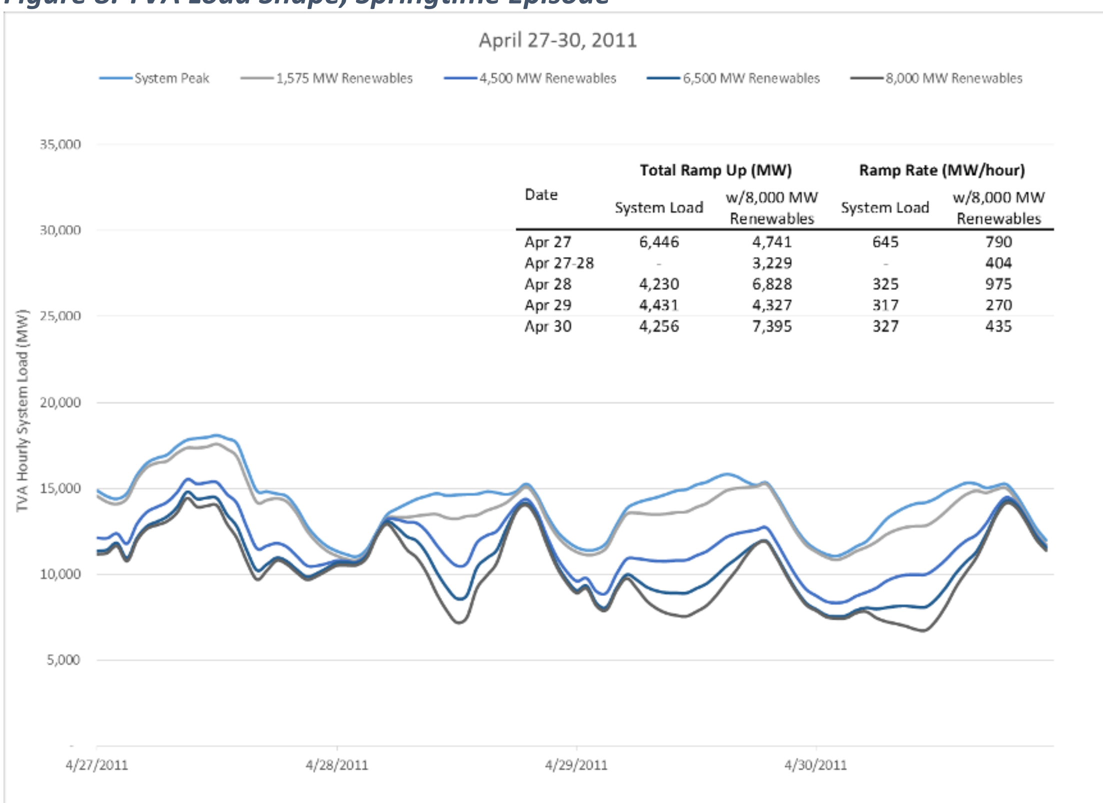
Date	Total Ramp Up (MW)		Ramp Rate (MW/hour)	
	System Load	w/7,300 MW Renewables	System Load	w/7,300 MW Renewables
Apr 2	3,405	5,008	200	835
Apr 3	4,495	6,009	281	668
Apr 4	7,702	7,671	453	451
Apr 5	5,428	6,795	679	971
Apr 6 am	4,822	4,897	804	979
Apr 6 pm	-	6,620	-	946

Figure 7: TVA Load Shape, Summer Peak Episode



Date	Total Ramp Up (MW) System Load	Total Ramp Up (MW) w/8,000 MW Renewables	Ramp Rate (MW/hour) System Load	Ramp Rate (MW/hour) w/8,000 MW Renewables
Aug 7	12,872	12,999	990	867
Aug 8	12,912	14,180	1,076	1,013
Aug 9	12,825	11,335	1,069	708
Aug 10	11,681	12,135	973	933

Figure 8: TVA Load Shape, Springtime Episode



Date	Total Ramp Up (MW) System Load	Total Ramp Up (MW) w/8,000 MW Renewables	Ramp Rate (MW/hour) System Load	Ramp Rate (MW/hour) w/8,000 MW Renewables
Apr 27	6,446	4,741	645	790
Apr 27-28	-	3,229	-	404
Apr 28	4,230	6,828	325	975
Apr 29	4,431	4,327	317	270
Apr 30	4,256	7,395	327	435

2. Statistical Analysis of Ramp Rates

To place these case studies in context, the entire data set was examined statistically for individual resources as well as the combined resource scenarios. Ramp rates were calculated over 1-hour increments.[3] This provided a broad view, considering hours in which renewable energy improved system ramp rates as well as those in which ramp rates became more challenging. The vast majority of utility ramp rates, with or without up to the maximum 8 GW of renewable energy analyzed here, remain below 5% of total system capacity. The main result of adding renewable energy into a ramp rate analysis is that some hours have increased ramps, and other hours have decreased ramps.

Because the utilities have similar peak loads and ramp rates, it was practical to apply the same simple analytic method to each utility. As discussed in Appendix A, due to limitations on available data, the data sets were different in size.

- Duke Energy (in the Carolinas): 1998-2012, including 131,496 hourly records
- Southern Company: 2003-2012, including 87,672 hourly records
- Tennessee Valley Authority: 1998-2012, including 131,496 hourly records

It should be noted that each of these utility systems is a dispatching authority, although each distributes power through affiliated utilities.

Hourly ramp rates were calculated and sorted into seven bins for each utility. Hourly ramp rates with an increase or decrease in (net) load of less than 1,000 MW were considered “low ramp rates.”[4] For each utility the low ramp rate represented 81-86% of the hourly ramp rates under reported historic system loads. Higher ramp (up or down) rates were grouped in increments of +/- 1,000 MW as illustrated on the graphs.

For comparison with the system load baseline, net loads were calculated at increasing levels of renewable energy development. For individual resources, net loads were calculated for 1-5 GW of nameplate capacity. The study of ramp rates for individual resources included a total of twelve datasets (3, 4 and 5 distinct resource technologies for the utilities). A complete set of net load graphs was not completed after it became clear that the findings were repetitive. Furthermore, it should be re-emphasized that it is not likely that a utility would develop several gigawatts of capacity from a single renewable energy technology, leaving the others undeveloped.

For solar power, all analyses showed that for the first several gigawatts of solar power development, the number of hours with high ramp up rates declines somewhat, while the number of hours with high ramp down rates shows a slight increase. Overall, for solar power, up to about 4 GW of development can be supported with operating ramps being *either slightly improved or about the same* as the system without solar. Beyond 4 GW, ramp rates on the system slowly increase in overall challenge but there is no point at which dramatic changes in system ramp rates occur. This trend is illustrated in Figure 9, which

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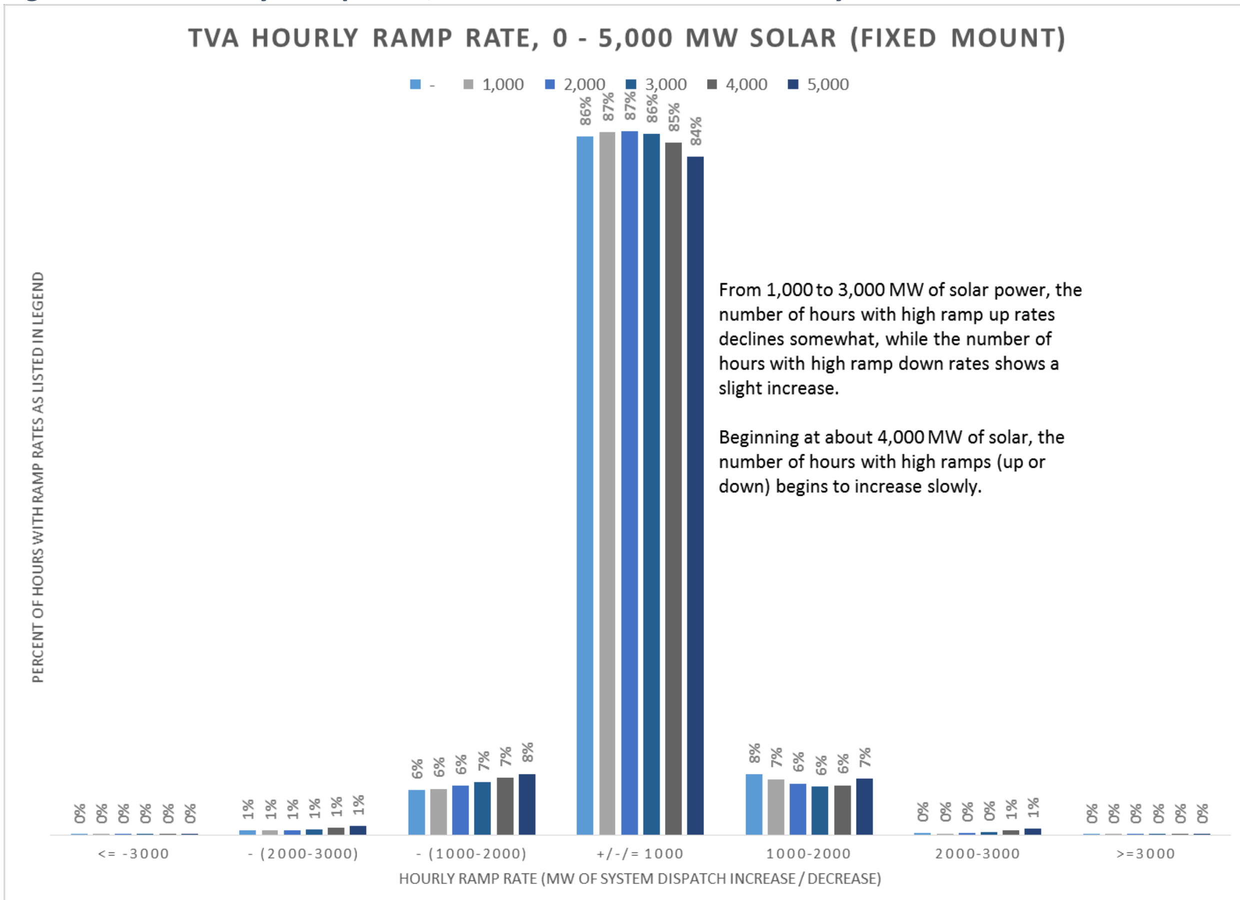
[3] Three-hour ramp rates were also calculated for a portion of the analysis, but the results were not sufficiently different from the one-hour ramp rate studies to suggest any benefit to more extensive study.

[4] This “low ramp rate” value was selected arbitrarily and is not based on any particular system operation standard.

considers fixed mount solar systems over an hourly interval. Similar findings occurred for solar tracking systems, for three-hour ramp rates, and for other utilities.

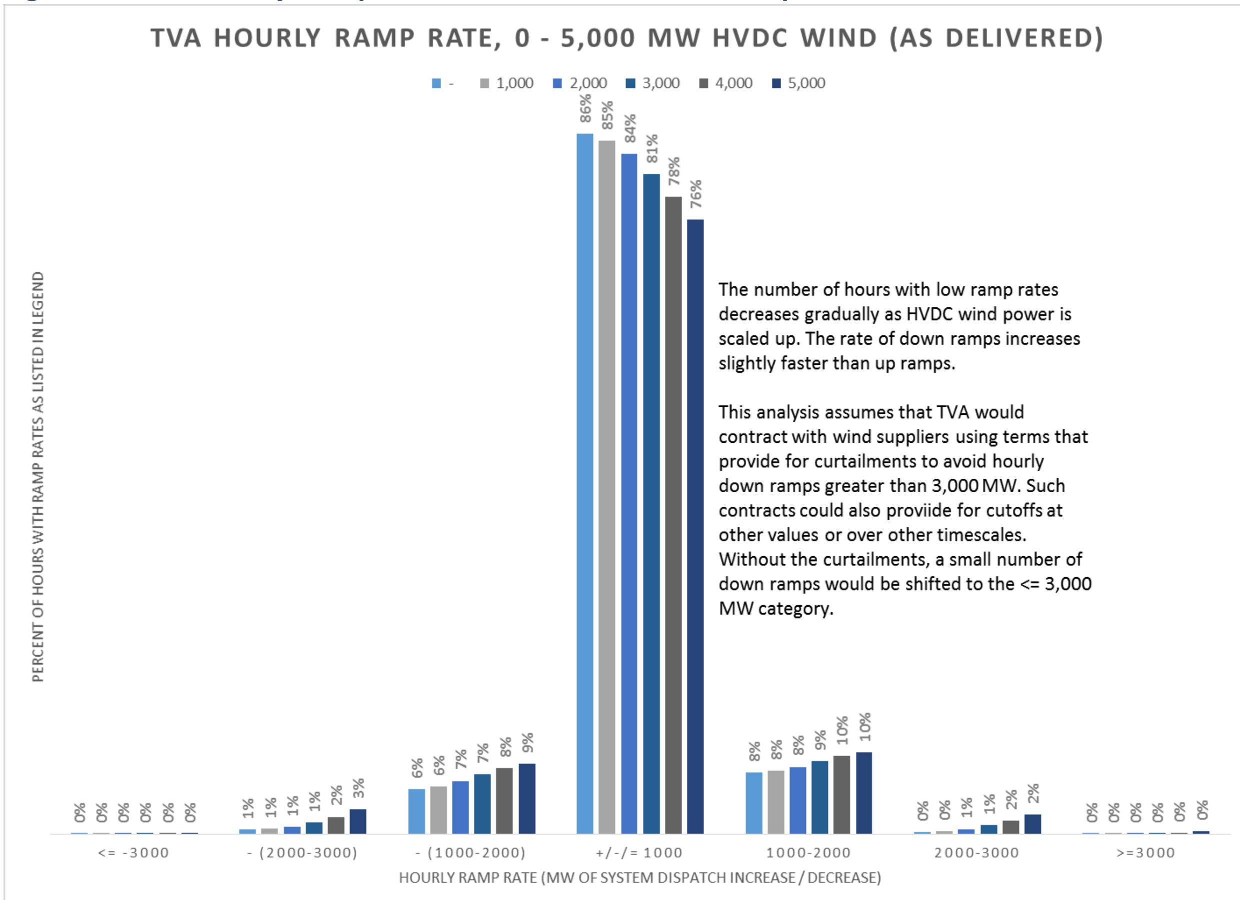
Figure 9: TVA Hourly Ramp Rate, 0 – 5 GW Solar Fixed Mount Systems



Wind energy presents a more significant operational challenge in terms of ramp rates. However, at the levels of wind power that are likely to be deployed on utility systems, the impacts of wind power on ramp rates appears to be modest. For example, due to the size of projects under development and utility standards regarding primary reserves and resource availability, TVA is unlikely to add more than 5 GW of wind power to its system from all sources (whether regional, interconnected via existing AC transmission, or imported via new HVDC transmission projects) over the next decade. Other Southeastern utility systems are more constrained in terms of access to wind resources over the next decade.

As illustrated in Figure 10, even 5 GW of wind power modeled on the basis of HVDC wind resources would have a relatively modest impact on the TVA system. The main impact appears to be in terms of ramping the system down at a greater frequency. Fortunately, this impact can be mitigated by introducing contract terms that provide the utility with the opportunity to curtail wind generation to allow for other resources to be ramped down more gradually (after a brief curtailment, the wind generation would be restored to full output). Similar, but somewhat less significant effects occurred for regional wind resources; regional wind resources are unlikely to be developed at the same scale as HVDC wind imports in any event, so the system impacts on ramping would be of less consequence.

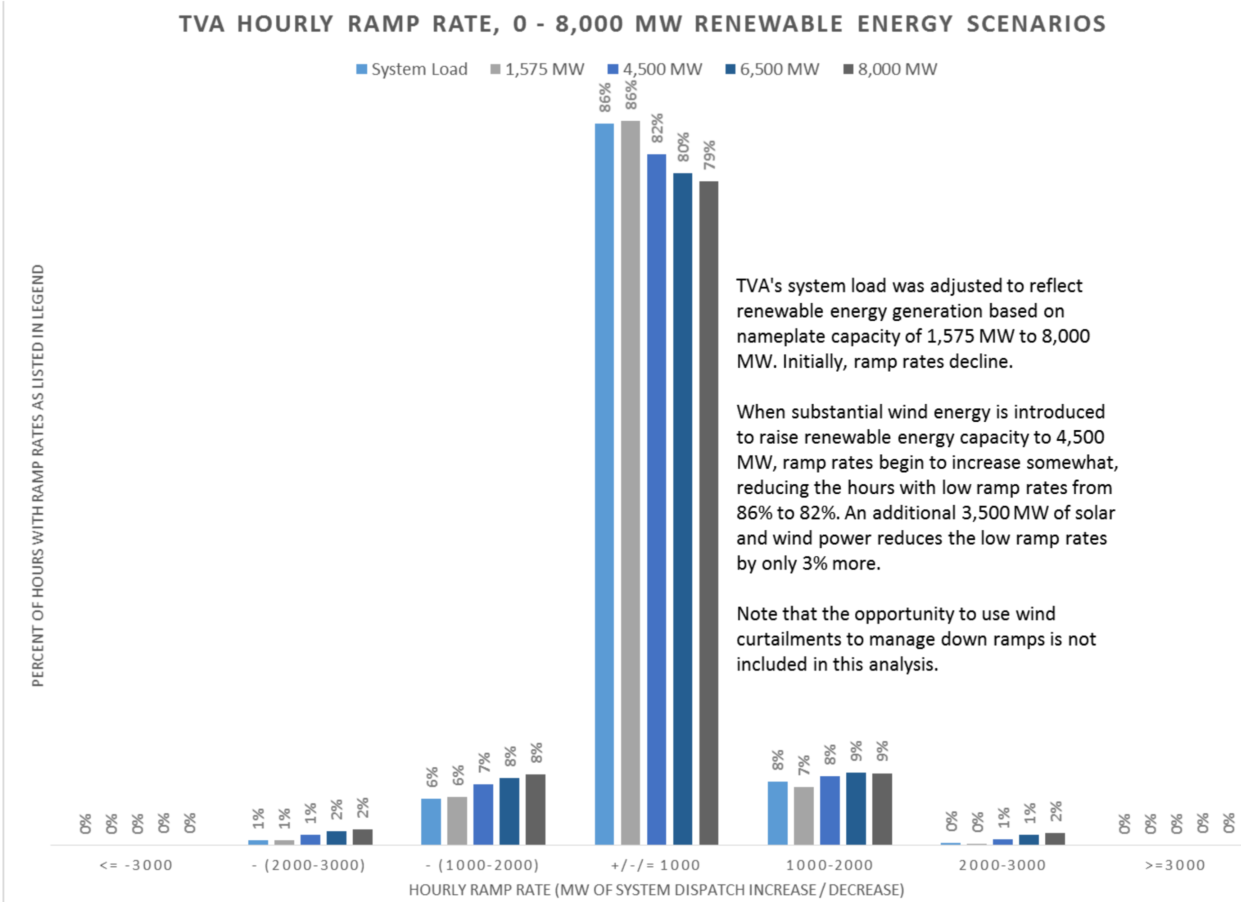
Figure 10: TVA Hourly Ramp Rate, 0 – 5 GW HVDC Wind Imports



In scenarios reflecting various blends of renewable energy resource technologies, the method was altered slightly. While retaining an identical baseline of no renewable energy, the incremental amounts of renewable energy corresponded to the renewable energy development scenarios described in Appendix A, Section 4. The resulting analyses of the three utility scenarios are presented in Figure 11, Figure 12, and Figure 13.

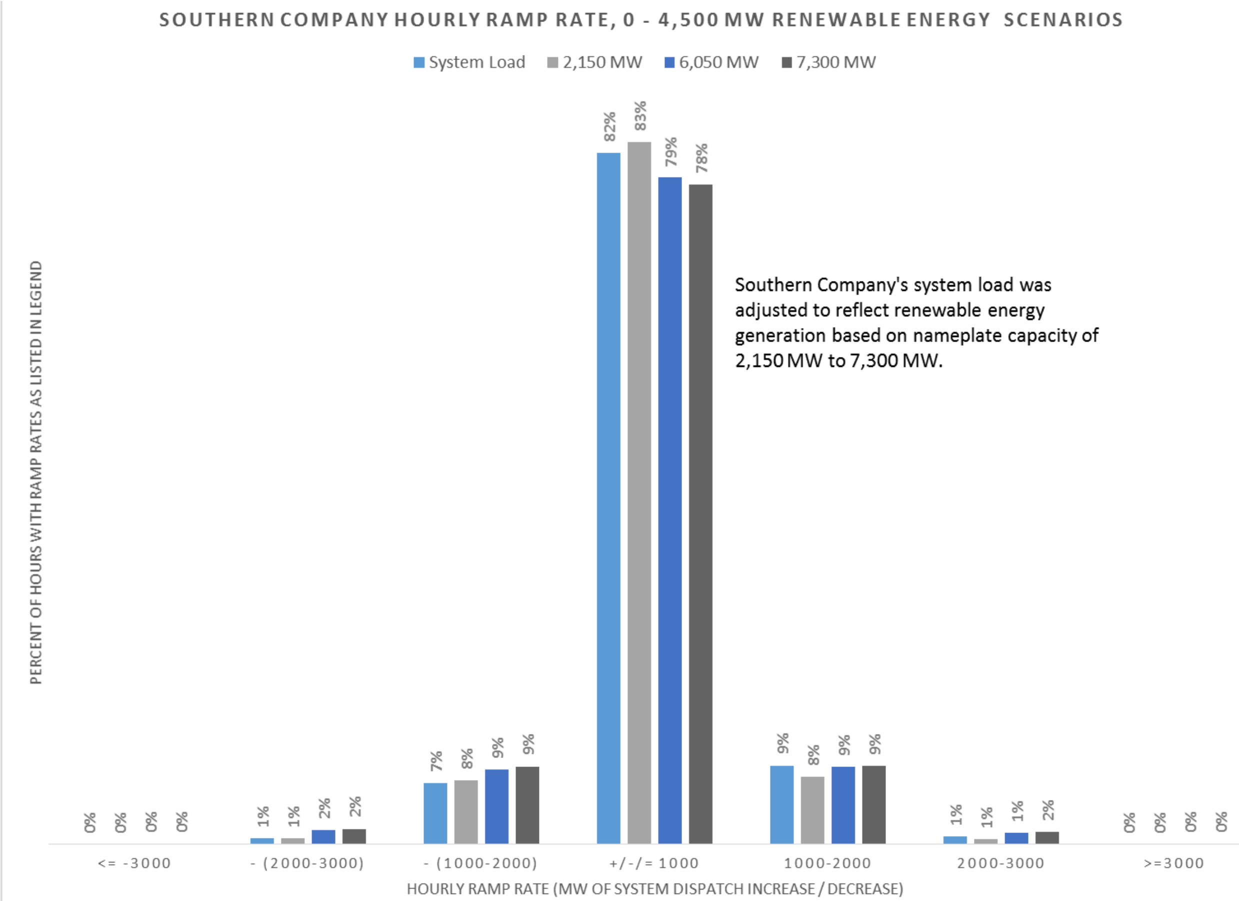
These analyses suggest that wind has more impact than solar on the magnitude of changes to ramp rates. For example, TVA Tranche 2 (4,500 MW in Figure 11) results in a reduction in low ramp rates from 86% of hours to 82% of hours. The composition of Tranche 2 is dominated by 3,000 MW of wind, mostly HVDC imports (see Appendix A, Section 4). This correlates closely with the ramp rate impacts of HVDC wind, a reduction to 81%, for 3,000 MW of HVDC wind imports (see Figure 10). The close relationship between the HVDC-only ramp rates and the combined renewable energy scenario contrasts with other findings in this analysis. For combined resource scenarios, the DCFs for solar and wind tended to combine in a synergistic manner at higher levels of resource development. With respect to ramp rates, there appears to be relatively little synergy.

Figure 11: TVA Hourly Ramp Rate, 0 – 8 GW Renewable Energy Scenario



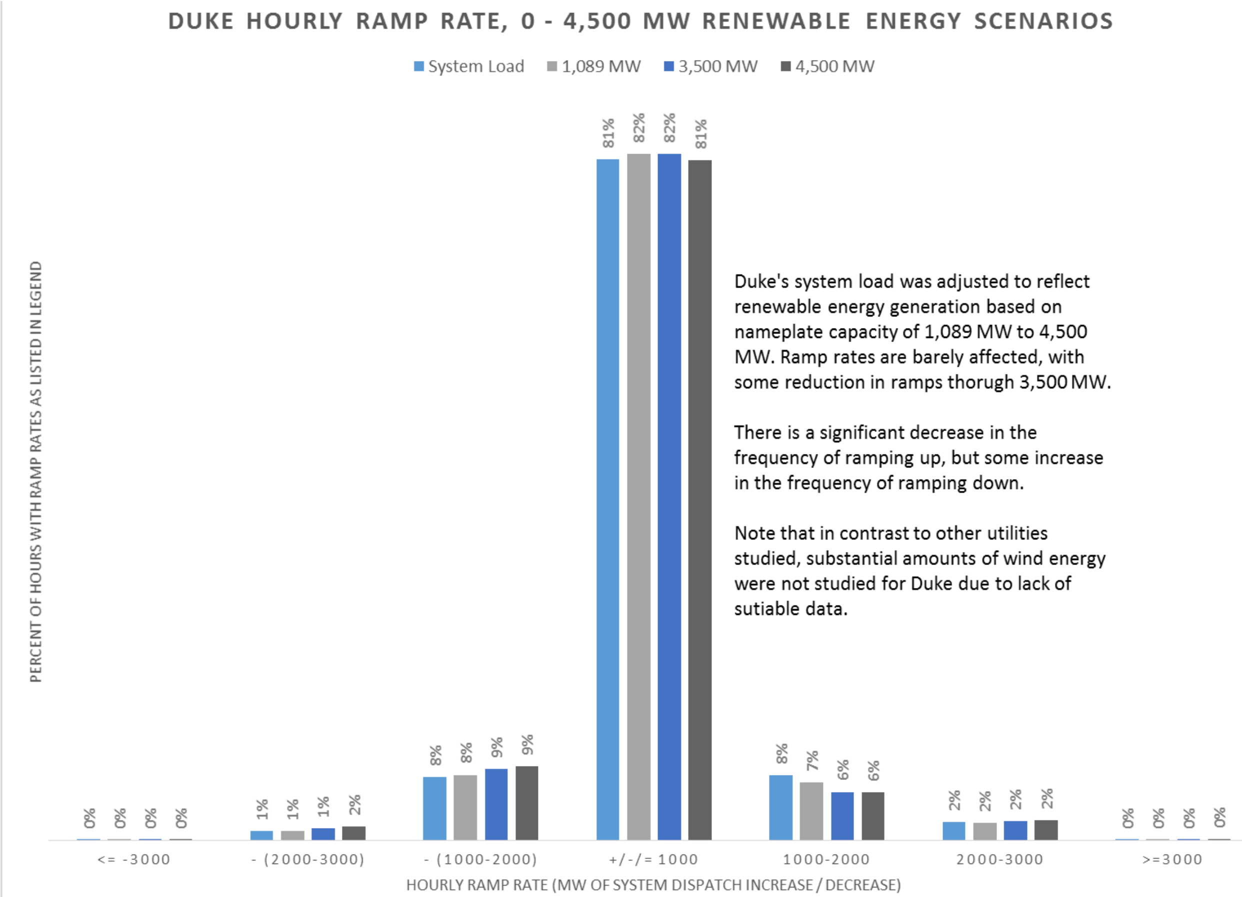
The results for Southern Company, as illustrated in Figure 12, are similar to those for TVA. The main impact on ramp rate frequencies relates to the introduction of HVDC wind resources, but the impacts are relatively modest.

Figure 12: Southern Company Hourly Ramp Rate, 0 – 7.3 GW Renewable Energy Scenarios



For Duke Energy, as illustrated in Figure 13, ramp rate frequencies are not affected very much since the project did not have access to wind data for resources available to the Duke Energy region. The performance of the Duke Energy scenario is similar to solar (see Figure 9 for example) because of the emphasis on solar energy resources.

Figure 13: Duke Energy Hourly Ramp Rate, 0 – 7.3 GW Renewable Energy Scenarios



Attachment B
Impacts of Nuclear Energy Generation

In addition to nuclear power's lack of resiliency as discussed in our main comments, there are host of significant non-air quality impacts that EPA must consider before finalizing the Clean Power Plan. In this attachment, we address the following points:

a) *Nuclear energy is extremely water-intensive;*
b) *Nuclear energy produces highly radioactive, long-lived nuclear waste;*
c) *Nuclear energy is heavily subsidized resulting in significant hidden costs;*
d) *Nuclear energy poses nuclear proliferation and national security risks;*
e) *Nuclear power plant accidents can cause catastrophic consequences;*
f) *Nuclear power plants produce and release harmful radiation; and*
g) *The Uranium fuel chain is incredibly damaging to the public health and the environment.*

a) Nuclear energy is extremely water-intensive.

On average, nuclear energy in the most water-intensive of traditional energy resources, followed by coal and natural gas.[1] Water-intensive nuclear generation is currently included in Building Block 3 along with renewables such as solar PV and wind, despite their near zero water requirements. Power plants across the country are competing with other water use sectors and with other crucial needs such as for drinking water, agriculture and recreational needs.

The water impacts from nuclear energy are not just related to water supply issues. In terms of water quality, another problem with water discharged from nuclear energy plants is its temperature. This water is warmer than the water into which it is discharged, and the resulting "thermal plumes" cause stress on the aquatic life, including commercially important fish and shellfish. Warmer water temperatures proximate to a nuclear energy plant result in conditions that effect the feeding and breeding patterns of various species. For instance, nuclear energy plants aggravate the problem of low dissolved oxygen levels through its heated discharge to lakes and rivers. The state of Tennessee voiced concerns to the NRC about this impact on mussel beds downstream from the Sequoyah nuclear plant, which suffered from even lower oxygen levels as it is also downstream from the Watts Bar nuclear plant.[2] Further, when shutdowns occur, large and rapid fluctuations in the water temperature can harm or kill aquatic species.

Hazardous chemicals and heavy metals are discharged into waterways during routine operations of nuclear energy plants that are harmful to fish and shellfish. Permit guidelines allow discharges of boric acid, lithium hydroxide, sulfuric acid, hydrazine, sodium hydroxide, phosphates, biocides, copper, zinc, and chromium. Chlorine is widely used as a biocide and is a large source

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[1] Averyt, K., J. Fisher, A. Huber-Lee, A. Lewis, J. Macknick, N. Madden, J. Rogers, and S. Tellinghuisen. 2011. *Freshwater use by U.S. power plants: Electricity's thirst for a precious resource*. A report of the Energy and Water in a Warming World Initiative. Cambridge, MA: Union of Concerned Scientists. November. p.13. Available at http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/freshwater-use-by-us-power-plants.html#.VGkEw1fF-4o.
[2] U.S. NRC, NUREG-1437, 1996, vol 1. p. 4-23.

of chemically toxic releases to the aquatic environment.[3]

Besides thermal plumes and toxic chemicals, nuclear power plants damage aquatic life in other ways. According to the NRC, the entrapment and impingement of fish, crabs, shrimp, jellyfish, turtles, manatees, seals, and alligators has occurred at nuclear power plants throughout the nation. This essentially means they have been trapped against an intake screen or actually pulled through the entire condenser cooling system. In many cases, the species affected are endangered or threatened—most notably sea turtles. Numerous endangered sea turtle species have been maimed or killed at the St. Lucie nuclear power plant in Florida. There were 5,420 instances recorded from 1976 to 1997, with 190 of those being lethal. The EPA estimated that the Brunswick nuclear power plant in North Carolina destroyed 66% of juvenile fish in the Cape Fear Estuary.[4]

Additionally, new nuclear reactors are also extremely water-intensive. To highlight a Southeast example, Plant Vogtle in Burke County, Georgia located along the Savannah River downstream of Augusta. The Savannah River is considered the third most toxic river in the country with more than 5 million pounds of toxic discharged into it,[5] the majority released between Augusta and Savannah. Currently, the two operating reactors are already one of the largest surface water users on the river, permitted to withdraw a maximum of 127 million gallons per day (MGD). On average, the two reactors withdraw approximately 67 MGD, returning less than one third for a consumptive loss of approximately 43 MGD.

Southern Nuclear has not yet received approval from the Georgia Environmental Protection Division (EPD) for the proposed Toshiba-Westinghouse AP1000 reactors' surface water withdrawal permit or discharge permit. The withdrawal permit application requested a 74 MGD maximum daily and 62 MGD monthly average with an estimated average of 41 MGD in consumptive loss. Combined daily maximum withdrawals from the Savannah River could be 201 MGD with an average 84 MGD consumptive loss. This means that the two existing and two proposed Vogtle reactors could consume enough water to supply over 1.1 million Georgians with drinking water.[6]

EPD has acknowledged a worst-case scenario of consumptive losses up to 88%.[7] This level of consumptive loss is extremely problematic during times of drought and low-flow period,

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[3] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, p. 17. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.

[4] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, p. 18. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.

[5] Environment Georgia Research & Policy Center, *Wasting Our Waterways: Toxic Industrial Pollution and Restoring the Promise of the Clean Water Act*, June 2014. Available at http://bit.ly/1q8AdiU. Also see http://savannahnow.com/news/2014-06-26/report-calls-savannah-river-third-most-toxic-america#.U9u7zIBdXjk.

[6] The average per capita daily water use in Georgia is 75 gallons from surface and ground water sources, http://ga.water.usgs.gov/infodata/wateruse/ & http://water.usgs.gov/watuse/tables/dotab.st.html. With water consumption for all 4 reactors (2 existing and 2 proposed) projected at approximately 84 mgd (43 mgd for the existing two reactors and 41 mgd for the proposed two reactors) that could mean the equivalent of over 1.1 million residents.

[7] Savannah Riverkeeper, Southern Alliance for Clean Energy, Southern Environmental Law Center, Turner Environmental Law Clinic at Emory Law School, Supplemental Comments to the Georgia Environmental Protection Division (EPD) on the draft Surface Draft Non-Farm Surface Water Withdrawal Permit – Southern Nuclear

especially for the already imperiled Savannah River that has severe dissolved oxygen deficiencies. Since no study of climate change has been included in the draft permit or application, it is unclear how much worse this situation could become decades into the future as the realities of global warming are realized across the region (the reactors are assumed to operate for at least 60 years).

As stated in our extensive comments to EPD:

> *The proposed water withdrawal of 74 MGD would further decrease water flow in the Savannah River, leading to increased water temperatures … If power plants in Georgia are already shutting down/reducing output because water is too warm or because of water shortages, then this water withdrawal permit for Plant Vogtle Units 3 & 4 will only exacerbate existing problems and potentially create unreasonable adverse effects on other users – for example, other power plants along the river may be forced to shut down or reduce output because of water problems.*[8]

There are less water-intensive cooling technologies that could drastically reduce the surface water withdrawal and consumptive loss from the proposed reactors but thus far, Southern Nuclear has not pursued such measures.[9] The significant threat that the expansion of Plant Vogtle poses for the Savannah River led the Georgia Water Coalition, a group of over 200 organizations representing more than a quarter of a million Georgians, to select Vogtle for the 2014 "Dirty Dozen" list that highlights the worst offenses to Georgia's waters.[10]

The situation at Plant Vogtle could be repeated at proposed new reactors sites across the country. For instance, FPL's plans to build two more reactors of the Toshiba-Westinghouse AP1000 design at their Turkey Point nuclear plant, will have similar water requirements to Plant Vogtle.

Operating Company – Vogtle Electric Generating Plant (Units 3 and 4), Permit No. 017-0191-11. Exhibit 5, May 15, 2014. Available at http://www.cleanenergy.org/wp-content/uploads/Ex5_DRAFTEPDRecommendation072412_Vogtle3and4_H2OPermit_051514.pdf. All materials filed with EPD filed by the above parties can be found here: http://blog.cleanenergy.org/2014/05/29/vogtle-reactors-guzzle-more-from-savannah-river/.

[8] Savannah Riverkeeper, Southern Alliance for Clean Energy, Southern Environmental Law Center, Turner Environmental Law Clinic at Emory Law School, Supplemental Comments to the Georgia Environmental Protection Division (EPD) on the draft Surface Draft Non-Farm Surface Water Withdrawal Permit – Southern Nuclear Operating Company – Vogtle Electric Generating Plant (Units 3 and 4), Permit No. 017-0191-11. May 15, 2014. Available at http://www.cleanenergy.org/wp-content/uploads/SACE_SRK_SupplementalEPDVogtleH2OPermitComments_051514.pdf. All comments and exhibits, including expert testimony, can be found at http://blog.cleanenergy.org/2014/05/29/vogtle-reactors-guzzle-more-from-savannah-river/.

[9] Savannah Riverkeeper, Southern Alliance for Clean Energy, Southern Environmental Law Center, Turner Environmental Law Clinic at Emory Law School, Supplemental Comments to the Georgia Environmental Protection Division (EPD) on the draft Surface Draft Non-Farm Surface Water Withdrawal Permit – Southern Nuclear Operating Company – Vogtle Electric Generating Plant (Units 3 and 4), Permit No. 017-0191-11. Exhibit 1, Expert declaration from Bill Powers, Vogtle Units 3 and 4: Feasible and Cost□Effective Water Conservation Measures, May 15, 2014. Available at http://www.cleanenergy.org/wp-content/uploads/Ex1_PowersEgr_Vogtle3and4_H2OPermitReport_051514.pdf

[10] Find the full 2014 Dirty Dozen report at http://www.garivers.org/gawater/dirtydozen2014.html; the specific Vogtle/Savannah River selection is available at http://www.garivers.org/gawater/pdf%20files/2014DirtyDozen/07SavannahRiver.pdf.

According to FPL, public and commercial water use in Miami-Dade County is projected to increase 35% by 2025, while thermoelectric energy use in the county is projected to increase 3224% in the same time span.[11]

b) Nuclear energy produces highly radioactive, long-lived nuclear waste.

Another unique aspect of nuclear energy is the waste created in the form of spent nuclear fuel and the EPA has failed to address the human health, environment and economic consequences this waste poses. More than sixty years since the start of the nuclear energy industry, there is still no credible, long-term plan for management and storage of the country's high level radioactive nuclear waste produced by nuclear power plants. This situation has cost billions of dollars to ratepayers of nuclear utilities, states with nuclear power plants and U.S. taxpayers.[12] Similar to climate change, future generations will also be dealing with nuclear waste.

Standing near unshielded spent fuel would be quickly fatal. According to the Nuclear Regulatory Commission (NRC), ten years after spent fuel is removed from a reactor, the radiation dose at one meter from a normal spent fuel assembly exceeds 20,000 rems per hour. Immediate incapacitation and death is estimated to occur at 450-600 rems. These spent fuel rods will remain radioactive for well over 250,000 years and must be isolated from humans and the environment.[13] This presumes institutional controls will be in place far long than human society has existed. EPA has not addressed the costs associated with such long-term management and the consequences that could occur if institutional controls are lost.

Nuclear waste is currently stored on-site at power plants across the country. At some point, this high-level radioactive waste will likely be transported, putting communities along transportation at risk. EPA did not address these costs or risks in the draft CPP.

In 2011 the U.S. Court of Appeals voided the NRC's "waste confidence" rule, under which the NRC claimed it could safely store wastes and that it would have a federal waste repository when needed.[14] The NRC formally suspended all reactor licensing and license extension decisions, pending completion of a generic environmental impact statement and a new waste confidence rule that would allow it to meet the strictures of

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[11] Florida Power and Light, Turkey Point COL Application, Rev. 0, p. 2.5-34, June 30, 2009.

[12] In terms of the Nuclear Waste Fund, some 78 lawsuits have been filed and dozens of lawsuits have yet to be tried. To date, damages and judgments in the amount of $2 billion have been paid from the taxpayer-funded Judgment Fund, which is overseen by the DOJ. "DOE currently estimates that total damage awards to utilities could amount to $20.8 billion if the federal government begins accepting spent fuel in 2020." See the Blue Ribbon Commission (BRC) report on America's Nuclear Future, page 79, Section 8.5 Dealing with Ongoing Litigation, available at http://cybercemetery.unt.edu/archive/brc/20120620220827/http://brc.gov/index.php?q=announcement/brc-releases-their-final-report.

[13] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, pp. 3-5. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.

[14] United States Court of Appeals for the District of Columbia Circuit. No. 11-1045. State of New York, et al., Petitioners v. Nuclear Regulatory Commission and United States of America, Respondents; State of New Jersey, et al., Intervenors. Consolidated with 11-1051, 11-1056, 11-1057. On Petitions for Review of Orders of the Nuclear Regulatory Commission Argued March 16, 2012. Decided June 8, 2012. Available at http://www.cadc.uscourts.gov/internet/opinions.nsf/57ACA94A8FFAD8AF85257A1700502AA4/$file/11-1045-1377720.pdf. Heading: "USCA Case #11-1045 Document #1377720 Filed: 06/08/2012." 681 F.3d 471.

the court's ruling. The NRC lifted its moratorium on licensing decisions in August 2014 without issuing a new waste confidence rule on the ground that spent fuel could be stored safely on site or at a consolidated storage facility, yet to exist, if necessary for the indefinite future, even if a geologic repository never became available.[15]

We are concerned that EPA has made assumptions about nuclear safety and spent fuel generation and management in an area that is reserved by law for the U.S. Nuclear Regulatory Commission (NRC) – without any discussion of its rationale.

c) Nuclear energy is heavily subsidized resulting in significant hidden costs.

The nuclear energy industry has been in existence for well over sixty years and should be considered a mature industry that can stand on its own, without reliance of extensive subsidies. However, that is not the case. According to a 2001 Congressional Resource Service Brief to Congress, from 1948 to 1998, the U.S. spent more than $111 billion on total energy research and development. Sixty-six billion dollars, or 59% of that total, was spent on nuclear energy.[16]

The EPA failed to assess all the costs associated with nuclear energy, many of which are unique to this generation technology. In addition to the costs of construction, operations, maintenance, and fuel for a nuclear plant, there are the following costs that can affect utility ratepayers along with local, state and federal taxpayers:

- costs of transporting, storing, and safeguarding radioactive wastes
- regulatory costs
- state and federal radiation monitoring programs
- costs of producing nuclear fuel, such as uranium mining, milling conversion and enrichment
- economic damage from radioactive and other toxic contaminants during all stages of the extremely polluting uranium fuel chain
- decommissioning costs
- costs from a severe nuclear accident (e.g. Price Anderson Act)
- loss of property value linked to contaminated sites and their surroundings
- loss of economic development opportunities for surrounding communities
- costs accrued from major accidents, or the "meltdown potential"

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[15] U.S. Nuclear Regulatory Commission. "10 CFR Part 51: [NRC–2012–0246]: Continued Storage of Spent Nuclear Fuel: Final Rule," *Federal Register*, v. 79 (Sept. 19, 2014) : pp: 56238- 56263). Available at www.gpo.gov/fdsys/pkg/FR-2014-09-19/pdf/2014-22215.pdf. "Final Continued Storage Rule" "RIN 3150–AJ20"; United States. Nuclear Regulatory Commission. *Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel: Final Report*. (NUREG–2157) Washington, DC: NRC, September 2014. Available at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr2157/, with links to vol. 1, pbadupws.nrc.gov/docs/ML1419/ML14196A105.pdf, and vol. 2, pbadupws.nrc.gov/docs/ML1419/ML14196A107.pdf.; and Allison M. Macfarlane. *Chairman Macfarlane's Comments on SECY-14-0072: "Proposed Rule: Continued Storage of Spent Nuclear Fuel."* [Washington, DC: NRC], August 7, 2014. Available at http://www.nrc.gov/reading-rm/doc-collections/commission/cvr/2014/2014-0072vtr-amm.pdf.

[16] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, p. 14. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.

As stated previously, the two Vogtle reactors under construction in Georgia, are benefitting from numerous incentives and subsidies such as eligibility for substantial production tax credits, $8.3 billion in taxpayer-backed conditional nuclear loan guarantees and state legislation that charges Georgia Power ratepayers in advance for the financing costs associated with the new reactors.

d) Nuclear energy poses nuclear proliferation and national security risks.

The EPA failed to acknowledge an aspect that is particularly unique to nuclear energy – its contribution to nuclear proliferation. Plutonium is produced in the fuel rods during the operation of commercial nuclear reactors; this plutonium can be extracted to produce nuclear weapons. In the early days of nuclear energy development, concerns were raised over the inherent dangers in the proliferation of atomic energy and weapons. The spread of nuclear energy internationally has resulted in the spread of nuclear weapons.

Nuclear power plants, including the waste they create, also pose unique national security risks. This became more apparent in the post-9/11 world. Nuclear power plants along with the waste they create represent terrorist targets. Today, cyber security concerns represent a serious threat to the safe operation of nuclear plants and the remedies for dealing with such threats represent an economic cost as well.

e) Nuclear power plant accidents can cause catastrophic consequences.

The impacts of a severe accident at a nuclear plant were not considered in the draft CPP. An accident not only can cause massive environmental, public health and safety and economic impacts, but could also have fleet-wide implications preventing states from complying with CO2 emission reduction goals.

Japan's situation since the devastating multi-reactor nuclear accident at the Fukushima Dai-ichi facility in March 2011 demonstrates the significant consequences and risks—tens of thousands of people remain evacuated, tens of billions of dollars have already been spent for on-site efforts to secure the site and to begin immense stabilization and immediate and long-term remediation and decommissioning efforts.[17] Six reactors were lost at Fukushima Dai-ichi and eventually all of Japan's reactors were shutdown. For over a year, no reactors have operated in Japan.[18] This situation underscores the inflexibility of nuclear energy – it can be all or nothing, resulting in significant changes to anticipated or expected CO2 emissions reductions.

The EPA has not analyzed the serious economic costs posed by a nuclear energy accident in the draft CPP. But over fifty years ago, the U.S. government and the nuclear energy industry recognized the possibility of staggering financial losses in the event of a major accident. In 1957, the Price-Anderson Act was passed to encourage the commercial development of nuclear energy.

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[17] Mycle Schneider, Antony Froggatt et al., World Nuclear Industry Status Report 2014, July 2014. A detailed account of the current situation, evacuees' status, decommissioning efforts and costs, health impacts and more can be found in the section, "Fukushima: A status report," pp. 59-72. Available at http://www.worldnuclearreport.org/IMG/pdf/201408msc-worldnuclearreport2014-hr-v4.pdf.

[18] Mycle Schneider, Antony Froggatt et al., World Nuclear Industry Status Report 2014, July 2014, Annex 2: Japanese Nuclear Reactor Status, July 1, 2014, pp. 140-141. Available at http://www.worldnuclearreport.org/IMG/pdf/201408msc-worldnuclearreport2014-hr-v4.pdf.

It limits the financial losses of the utilities that own nuclear power reactors in case of a major accident and remains in place today, more than fifty years later. Congress encouraged creation of the American Nuclear Insurers (ANI), the only company that provides liability insurance for private U.S. nuclear reactors.[19] However, it is unlikely that the insurance would cover the losses from a serious accident. For example, according to the 1982 Congressional report, a severe accident at just one of the existing reactors at Plant Vogtle in Georgia could result in losses in excess of $70 billion (in 1982 dollars and 1980 population figures).[20]

Regulations developed and implemented after an accident by the U.S. Nuclear Regulatory Commission (NRC) could impact nuclear generation. The EPA must avoid putting safe operation of nuclear plants at risk due to States' requirements to comply with the CPP.

f) Nuclear power plants produce and release harmful radiation.[21]

There is no safe dose of ionizing radiation; genetic material can be damaged and resulting mutations can be passed from generation to generation. All nuclear power plants release radioactive contaminants such as Cesium–137, Strontium–90, Tritium, and radioactive Iodine into the air, soil, and water during normal, daily operations. Airborne radioactive contaminants pollute nearby crops and vegetation. Farm animals that feed on the crops and vegetation concentrate these contaminants in their meat and milk. Cesium-137 collects in muscle tissue and Strontium-90 collects in the bones. Non-cancer effects from exposure to Strontium-90 include higher infant mortality rates and more early fetal deaths associated with heart and circulatory defects. Tritium, a radioactive isotope of hydrogen that is produced at all nuclear reactors, acts like water in the body and can pass through the placenta to harm a developing fetus.

g) The Uranium fuel chain is incredibly damaging to the environment.[22]
Further debunking the "clean energy" label for nuclear energy are the environmental and health consequences from the production of uranium fuel, which is highly energy and waste intensive, requiring uranium mining, milling, conversion, enrichment, and fabrication. The types of waste created by a one-year operation of a typical 1000 MW nuclear reactor include 179,728 tons of uranium mill tailings, 0.2 metric tons of plutonium waste, 159 tons of reactor fuels as well as weapons grade plutonium. The EPA must address the impacts from the full uranium fuel chain, from the front end to the back end, before finalizing the rule.

Uranium ore is typically mined, like coal, to be used as a fuel source. Uranium is both radioactive and a chemical toxin. Additionally, numerous heavy metals present in uranium ore can have adverse health effects. Many uranium mines in the United States are on Native American lands. Nearly one third of these mines are located within the Navajo nation. The mines have had a negative effect on the quality of life of Native Americans living near the mines.

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[19] See American Nuclear Insurers, "ANI History." Available at http://www.amnucins.com/History.html.
[20] U.S. House of Representatives, Committee on Interior and Insular Affairs: Subcommittee on Oversight & Investigations, Calculation of Reactor Accident Consequences (CRAC2) for U.S. Nuclear Power Plants (Health Effects & Costs), November 1, 1982. Available at https://www.nirs.org/reactorwatch/accidents/crac2.pdf.
[21] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, pp. 1-2. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.
[22] Southern Alliance for Clean Energy, Code Red Alert: Confronting Nuclear Power in Georgia, May 2004, Appendix C. Available at http://www.cleanenergy.org/wp-content/uploads/Code-Red-Report-FINAL.pdf.

Milling is incredibly polluting – it consists of chemically separating uranium from other ore components. A thousand tons of ore must be processed to get just 2 tons of uranium. The waste produced is known as "mill tailings," which are often left near the land surrounding the mine, creating another dangerous legacy of the mining process. For typical uranium concentrations, the tailings contain 85 percent of the radioactivity in the original ore along with toxic chemicals and heavy metals. Furthermore, the volume of mill tailings is enormous and the majority of the radioactive components are extremely long-lived. Unfortunately, a large portion of mill tailings in the United States were "grandfathered" when more protective standards began to be implemented in the late 1970s, leaving behind more than 100 million tons of uranium waste with limited regulatory oversight.

The mill tailings can infiltrate surrounding waterways. In 1979, near Churchrock, New Mexico, a uranium mill tailings dam broke, dumping nearly 100 million gallons of liquid radioactive tailings and 1000 tons of solid tailings into a surrounding area, spreading nearly 60 miles from the facility. The Rio Puerco River was contaminated and the local Native American tribe was devastated since their water source was forever rendered toxic by the tailings