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February 10, 2011

VIA HAND DELIVERY

Ms. Renné Vance
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: Investigation of Integrated Resource Planning in North Carolina - 2010
Docket No. E-100, Sub 128

Dear Ms. Vance:

Enclosed for filing in the above-referenced docket on behalf of Southern Alliance for Clean Energy are the following documents:

- An original and 18 copies of the Initial Comments of Southern Alliance for Clean Energy (**Confidential Version**). *This document contains confidential data and should be filed under seal.*
- An original and 30 copies of the Initial Comments of Southern Alliance for Clean Energy (**Public Version**).

By copy of this letter, I am serving a copy of the Public Version of the Initial Comments on all parties of record. Copies of the Confidential Version will be provided upon request to parties who have executed appropriate confidentiality agreement(s).

Sincerely,

Robin G. Dunn

Robin G. Dunn

GT/rgd
Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 128

In the Matter of: Investigation of Integrated Resource Planning in North Carolina – 2010	))))	**INITIAL COMMENTS OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**

PURSUANT TO North Carolina Utilities Commission Rule R8-60(j) and the Commission's January 19, 2011 Order Granting Extension of Time, intervenor Southern Alliance for Clean Energy ("SACE"), through counsel, files these initial comments on the biennial Integrated Resource Plans ("IRPs") of Duke Energy Carolinas, LLC ("Duke") and Progress Energy Carolinas, Inc. ("PEC").[1]

I. SUMMARY OF FINDINGS.

- Portfolios including Duke's "High DSM" case are the lowest cost and lowest risk portfolios in Duke's IRP.
- Duke and PEC did not properly consider energy efficiency in their evaluation of resource options.
- Duke's IRP overstates the company's need for new generating capacity.
- Duke and PEC do not incorporate realistic assumptions about the cost of new nuclear generation in their IRPs.
- Neither Duke nor PEC has shown in its 2010 IRP that it has a realistic plan for reducing its greenhouse gas emissions.
- Both Duke and PEC have prudently decided to retire their existing unscrubbed coal-fired generating units, but neither utility shows in the IRP that continued operation of their scrubbed coal units is economical.
- Duke and PEC have not evaluated renewable resources beyond minimum REPS compliance with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard.
- Modeling of economic impacts would inform the evaluation of resource portfolios in the IRPs.

II. LEGAL FRAMEWORK FOR RESOURCE PLANNING.

In North Carolina, electric utility resource planning must result in the "the least cost mix of generation and demand-reduction measures which is achievable . . . ." N.C. Gen. Stat. § 62-2(3a). This "least cost mix" includes the "entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs." Id. Commission Rule R8-60 requires each electric utility to file a biennial report of its integrated resource planning process, with updates filed in the off years. As the Commission stated in its order on the 2009 IRPs, "[t]he biennial reports are to contain all required information, full and robust analyses and sensitivities, which should

[1] These comments were prepared with the assistance of David Schlissel, Schlissel Technical Consulting, and John D. Wilson, Director of Research for SACE.

encompass a range of scenarios including potential regulatory changes." Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket Nos. E-100, Sub 118 and E-100, Sub 124 (Aug. 10, 2010) ("2009 IRP Order") at 20.

Commission Rule R8-60 sets forth certain minimum IRP filing requirements. The rule provides, among other things, that each utility must:

- Provide a 15-year forecast of demand-side resources. Rule R8-60(c)(1).
- Conduct a "comprehensive analysis" of demand-side and supply-side resource options. Rule R8-60(c)(2) and (f).
- "[C]onsider and compare . . . both demand-side and supply side [resource] options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system." Rule R8-60(g).
- "[P]rovide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment" as well as "general information on any changes to the methods and assumptions used in the assessment . . ." Rule R8-60(i)(6). The results of the assessment must include programs "evaluated but rejected" by the utility. Id.
- Describe and summarize "its analyses of potential resource options and combinations of resource options performed by it . . . to determine its integrated resource plan." Rule R8-60(i)(8).

Both Duke and PEC failed to comply with these minimum filing requirements related to their analysis of Demand Side Management ("DSM") resources. Specifically, they both failed to describe the capacity and energy, number of customers and other information for each program over the 15-year period, as required by Rule R8-60. The utilities should amend their IRPs to provide this information.

PEC's IRP contains two additional informational deficiencies, which also plagued its 2009 IRP. First, although PEC referenced an update to its DSM Potential Study, PEC provided only a one-sentence summary of the update results. This limited disclosure does not satisfy PEC's obligation to provide "a descriptive summary of each analysis performed or used by the utility in the assessment." Rule R8-60(i)(6).[2] Second, PEC's IRP includes confusing and/or inconsistent data regarding the capacity and energy impacts of its demand-side resource forecast. As in the 2009 IRP, there are discrepancies between Table 1 and Appendix E data. Furthermore, data provided by PEC in response to discovery requests also appeared to be inconsistent with both Table 1 and Appendix E. PEC should amend its 2010 IRP to correct these deficiencies.

[2] In response to a SACE data request, PEC provided updated information for Tables 15-17 in the potential study. PEC should have filed this information with its IRP, along with updates to Tables 5-8, 11, 13 and 14 and Figures 3-4.

III. DUKE SHOULD HAVE PRIORITIZED ITS "HIGH DSM" ALTERNATIVE.

Duke modeled several resource portfolios in its IRP analysis. Some of these portfolios used a "High Energy Efficiency" or "High DSM" case, which "includes the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales each subsequent year until the load impacts reach the economic potential identified by the 2007 market potential study," i.e., a 13 percent decrease in retail sales. Duke Energy Carolinas Integrated Resource Plan (September 1, 2010) ("Duke 2010 IRP") at 88. Duke did not select a portfolio with the "High DSM" case, however, despite the fact that the portfolios incorporating Duke's "High DSM" case cost less, have lower risk, and appear to result in lower average electricity rates than does the so-called "optimal plan." As a result, Duke's plan does not result in the "least cost mix" of resources.

1. Duke's High DSM case results in lower cost to customers.

A primary criterion in Duke's quantitative analysis of resource portfolios is "minimizing the long-run revenue requirements to customers." Id. at 85. This criterion is consistent with Duke's least-cost planning obligation under N.C. Gen. Stat. § 62-2(3a). Duke defines "long-run" as a "50-year analysis time frame," and costs to customers are represented by the present value revenue requirement ("PVRR"), or the "costs to customers for the Company to recover system production costs and new capital incurred." Id. at 91. Duke selected three resource portfolios for testing under base assumptions and sensitivities: 1) no new nuclear capacity (the CT/CC portfolio); 2) full ownership of new nuclear capacity (the 2 Nuclear Units portfolio); and 3) shared ownership of new nuclear capacity (the 1 Nuclear Unit portfolio). Duke concluded that the "2 Nuclear Unit portfolios resulted in a lower cost to customer in every case with the exception of increased nuclear capital cost and lower fuel cost." Id. However, Duke also modeled a number of portfolios incorporating the "High DSM case" and provided the modeling files to SACE pursuant to a data request. When those "High DSM" portfolios are considered, the eight lowest cost portfolios are:
[BEGIN CONFIDENTIAL

[redacted]

• [redacted] END CONFIDENTIAL]

Attachment 1 shows that, based on Duke's quantitative analysis, ***all portfolios with High DSM cost at least*** [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] ***than the "optimal plan" over the 50-year analysis time frame.***

2. Duke's High DSM case would expose customers to less risk of cost increases.

A second criterion used by Duke in its quantitative analysis is the "impact of various risk factors on the costs to serve customers." Duke 2010 IRP at 86. Duke analyzes the risk associated with the various portfolios by comparing them across a range of sensitivities. For example, although the cost-effectiveness of the delayed 2 Nuclear Unit portfolio is slightly better than the "optimal plan," Duke explains that "if fuel prices or CO_2 prices are higher than the fundamental assumptions or if Clean Energy legislation is passed, nuclear generation in the 2021 timeframe is the preferred portfolio."[3] Id. at 91.

Using a similar approach, Duke's quantitative analysis shows that the "High DSM" strategy would reduce system risk due to fuel price and CO_2 price variability. In combination with every level of gas and nuclear supply-side investment considered, the "High DSM" strategy mitigates the impact of high fuel and high CO_2 prices by about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].[4] Because both nuclear and DSM have relatively low annual expenses (fuel and operating costs) compared to fossil fuel generation, they are both vulnerable to construction (or capital) cost increases. For every 10% change in capital cost, portfolio PVRRs change by about [BEGIN CONFIDENTIAL [redacted] END CONFIDENITAL] per nuclear unit. Unfortunately, Duke did not evaluate the sensitivity of its "High DSM" strategy to cost escalation. However, a paired-comparison analysis suggests that replacement of 1 nuclear unit with the "High DSM" strategy saves about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in capital costs.[5] Since the capacity provided by both the nuclear unit and the high DSM case are similar, the base case assumption for DSM costs is about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] percent less than the equivalent in nuclear capacity.

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[3] The cost difference of the delayed schedule in the base case is [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL], which Duke considers to indicate cost effectiveness that is "approximately the same." However, under the high fuel price and two higher CO_2 price sensitivity tests, the 2021 schedule has an advantage of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. The risk mitigation value of the 2021 schedule is the relative difference, or BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].

[4] For example: In the high fuel sensitivity case, the 2021 nuclear schedule provides a risk mitigation value of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] (the difference in additional cost relative to the base case). The High DSM strategy provides a risk mitigation value of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. This risk mitigation value is in addition to the cost advantage in the base case of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] where the 2 nuclear unit (2021 schedule) portfolio is compared with and without the "High DSM" case. Similar findings are evident when evaluating the CT/CC portfolio; Duke did not evaluate fuel and CO2 price sensitivities for the 1 nuclear unit with "High DSM" load case.

[5] The PVRR of the capital cost is also affected by the slight decrease in natural gas (CT) units and the different construction schedule for natural gas units. The direction of the PVRR impact could not be inferred from available data due to the significantly different construction schedule. However, because the capital cost of nuclear plants is at least 4 times greater than that of gas units, it is likely that it would be a relatively small adjustment.

Table 1: Comparison of 1 Nuclear Unit Portfolio to Gas (CT/CC) with High DSM Portfolio [TABLE CONTAINS CONFIDENTIAL INFORMATION]

Capacity Additions	1N 2027	HDSM Gas	Difference
CT	[redacted]	[redacted]	[redacted]
CC	[redacted]	[redacted]	[redacted]
Nuclear	[redacted]	[redacted]	[redacted]
Nuclear Uprate	[redacted]	[redacted]	[redacted]
DSM	[redacted]	[redacted]	[redacted]
Capital cost (PVRR, billion)	[redacted]	[redacted]	[redacted]

Based on the [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] percent discount and the capacity cost comparison, it appears that the PVRR of the "High DSM" portfolio cost is on the order of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. Even if this cost were to double or triple (a capital cost sensitivity of 200-300 percent), the "High DSM" portfolios would still cost less and be more effective at mitigating the impact of fuel price variability or higher CO_2 prices. In short, even though Duke did not perform a capital cost sensitivity for the "High DSM" case, it is highly likely that it would be an additional advantage for demand-side resources over supply-side resources.

The major risk factor that is relevant to "High DSM," as compared to nuclear, is the impact of market or regulatory barriers to development of the efficiency resource. For example, the ability of industrial customers to "opt-out" of utility energy efficiency and demand response programs, combined with a lack of external accountability for self-directed industrial energy efficiency programs, means that the efficiency resource may be more difficult to develop than should be necessary. On the other hand, the numerous obstacles to timely, safe and cost effective development of nuclear power units are also well documented, as discussed later in these comments. Neither Duke nor PEC offer any clear explanation as to why the obstacles to developing demand-side resources aggressively are greater than the development of supply-side resources such as nuclear power.

3. The qualitative factors cited by Duke also favor the High DSM alternative.

In its discussion of a "regional nuclear approach," Duke cites load growth, financial impact, and regulatory uncertainty as reasons that a regional nuclear approach might be superior to single utility development. Duke 2010 IRP at 92. For each of these reasons, the High DSM alternative is also preferred to Duke's "optimal" plan.

First, Duke argues that a regional nuclear approach is preferable because "smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth." Id. Because the "High DSM" alternative strategy develops system resources on an annual basis, it is even more closely matched to projected load growth than the regional nuclear approach.

Second, Duke argues for the regional nuclear approach because "the substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases." Id. Again, the "High DSM" alternative strategy is preferable because:

- The "substantial capital cost" of the "High DSM" strategy is about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] less costly than the equivalent nuclear resource.
- The "High DSM" strategy is "phased in over a longer period of time" than any of the nuclear resource options. In fact, about half of the additional capacity included in the "High DSM" alternative strategy occurs in 2021 or later, after capital costs for the first nuclear unit are fully committed. Id., Tables 4.1 and 4.2 at 69-70.
- The "High DSM" strategy is far less sensitive to "risk if there were cost increases" than new nuclear capacity, as discussed above.

Energy efficiency could also benefit financially from a "regional approach," although Duke does not discuss this in its IRP. Regional marketing and partnerships with key efficiency vendors can help improve the effectiveness of programs in reaching customers and trade partners. For example, the Northwest Energy Efficiency Alliance currently manages six regional initiatives cooperatively funded by Bonneville Power Administration (representing approximately 130 public utilities), the Energy Trust of Oregon (working on behalf of Portland General Electric and Pacific Power) and 12 individual utilities.[6] The Northwest ENERGY STAR Homes Program resulted in a 13% electricity and 10% natural gas savings per ENERGY STAR certified home, with homes located in most or all utility service territories.[7]

Third, Duke argues that "using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time." Id. at 92. All of the portfolios Duke considered as alternatives to meet legislative or regulatory requirements included the "High DSM" strategy. Therefore, this third advantage is shared by the "High DSM" strategy.

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[6] Northwest Energy Efficiency Alliance, *A New Era of Energy Efficiency: 2009 Annual Report*, August 2010 (Attachment 2).

[7] KEMA, Inc., *Northwest ENERGY STAR Homes Energy Analysis: 2006-2007*, Northwest Energy Efficiency Alliance Report #10-217, August 2010.

4. The High DSM alternative would likely result in lower electric rates.

The "High DSM" alternative would likely result in lower electric rates, potentially decreasing rates by as much as [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] ¢/kWh in present value terms compared to the "optimal plan," as illustrated by Table 2.

Table 2: Rate Impact of "Optimal" v. High DSM" Plans
[TABLE CONTAINS CONFIDENTIAL INFORMATION]

	"Optimal Plan"	**"High DSM"**	**Difference**
Cost	[redacted]	[redacted]	[redacted]
Cost per year (50 years)	[redacted]	[redacted]	[redacted]
Average Retail Sales (2015-2025)	81,785 GWh	79,476 GWh	-
Rate	[redacted]	[redacted]	[redacted]

(Source: Tables 4.1 and 4.2, Responses to SACE data requests.)

In other words, the revenue requirement impact of lost sales is outweighed by the capital and production cost savings associated with selecting the "High DSM" strategy over the "optimal plan."[8]

5. PEC does not even consider the potential for additional energy efficiency or renewable resources as part of the resource plans that it evaluated.

In contrast to Duke's failure to select an identified resource portfolio with a high energy efficiency case, PEC failed to even model a "high efficiency" case. In its IRP, PEC identifies three alternative resource plans that it considered for scenario analysis. <u>See</u> PEC 2010 IRP, Figure A-3 at page A-5. However, PEC did not identify any scenario that included a portfolio with additional investments in energy efficiency (or renewable resources). Rather, these three alternative plans differed only in terms of the amount of gas-fired and nuclear capacity contained in each and in the timing for new additions of units with these technologies.

PEC's failure to model different levels of energy efficiency reveals a critical flaw in the Company's analysis. Progress Energy did not conduct a similar sensitivity analysis (even though the Commission's 2010 order called for "full and robust analyses and sensitivities"). SACE requests that the Commission direct PEC to evaluate a "High DSM" case as part of its least-cost IRP analysis. In the absence of relevant analysis, it is reasonable to assume that the results for PEC would be qualitatively similar to those for Duke.

[8] It should be noted that the costs evaluated in the IRP do not represent the full revenue requirement to Duke customers. A cost equalization analysis suggests that production and capital costs associated with this resource plan would have to be less than [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] of the total revenue requirement for the "High DSM" case to result in a rate increase. Considering the current share of total rates represented by fuel costs, this outcome is unlikely.

IV. DUKE AND PEC DID NOT PROPERLY CONSIDER ENERGY EFFICIENCY IN THEIR EVALUATION OF RESOURCE OPTIONS.

Energy efficiency is the least-cost system resource. Unlike supply-side resources, energy efficiency, even at aggressive levels, reduces customer utility bills. Energy efficiency also moderates rate increases by reducing or delaying the need for new generating capacity. In fact, states with leading energy efficiency programs often have electricity rates that are comparable to, or even lower than, North Carolina.[9] In addition to lower customer bills and rate moderation, the numerous benefits of energy efficiency include environmental quality improvements, water conservation, energy market price reductions, lower portfolio risk, economic development and job growth, and assistance for low-income populations.[10]

Despite these benefits, Duke and PEC significantly underestimate the potential energy efficiency savings in their IRPs. The utilities failed to consider the efficiency resource on an equivalent basis as supply-side resources, and therefore, their IRPs do not result in the "least-cost mix" of resource options. Together, PEC and Duke forecast cumulative energy savings of 5.2 percent of retail sales over the next fifteen years. This ten-year estimate is less than the five-year goals of most leading utilities. North Carolina's electric utilities can and should do better.

A. The Duke and PEC long-term efficiency savings projections lag behind those of leading utilities.

The cumulative impact of North Carolina's energy efficiency programs could reach the levels of leading utilities over the next ten to fifteen years if North Carolina's electric utilities adequately analyze and forecast demand-side resources. While Duke and PEC have improved their consideration of energy efficiency in selecting near-term resource options, these utilities still do not adequately consider energy efficiency in selecting long-term resource options.

Duke and PEC have begun to invest in energy efficiency at meaningful levels. The following table, which is based on data Duke provided to its advisory group (the "Collaborative"), indicates that Duke exceeded its 2010 performance targets while spending below anticipated cost levels.

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[9] John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.

[10] See, e.g., Marilyn A. Brown et al., Energy Efficiency in the South, Southeast Energy Effiicency Alliance (April, 12, 2010), http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

Table 3: Duke Energy 2010 Energy Efficiency Program Impacts and Costs

	IRP Forecast[11]	As Filed[12]	Projected[7]	% of Target
Energy Savings (GWh)	116	234	443	189%
Capacity Savings (MW)	800	368	889	242%
Cost ($ millions)	n/a	$35	$48	137%

Similar data for PEC is not readily available, but it is clear that both PEC and Duke have increased the amount of energy efficiency in their resource plans since the 2009 IRPs.[13] Despite this increase, however, North Carolina will remain in the bottom quarter of all states with energy efficiency standards. Duke and PEC expect to achieve about 5.2% and 3.6%, respectively, in cumulative energy savings from energy efficiency programs over the next decade—equivalent to an annual energy savings goal of 0.36 – 0.52%, which is among the lowest in the country. In fact, several utilities in other states anticipate achieving more energy savings in the next two to three years than North Carolina utilities expect to achieve over the next decade.

Figure 1 compares Duke's and PEC's projected energy efficiency savings to that of a generic "leading" utility.[14] This "leading" utility represents a reasonable point of comparison because a large number of individual utilities operate programs whose annual energy savings exceed 1% of retail sales.[15] Moreover, a 1% annual savings goal is consistent with the findings of recent studies, including a 2010 Georgia Tech meta-analysis of several potential studies in the South, which found that the achievable electric efficiency potential ranges from 7.2 to 13.6% after 10 years.[16]

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[11] Derived from data provided in response to a SACE data request.

[12] Cost savings for both "as filed" and "projected" exclude costs associated with Rider IS and SG due to lack of data. Annual "projected" impacts are extrapolated from 9 months data. "Projected" capacity savings assumes 293 MW of Rider IS and SG related savings based on the IRP. See Duke Energy Carolinas, "Carolinas September 2010 Portfolio Update Final," provided to the Duke Energy Efficiency Collaborative.

[13] The increase in Duke's forecast is primarily related to addressing certain technical defects. The increase in PEC's forecast is primarily related to incorporating additional measures and updated assumptions.

[14] The leading utility is modeled with a 1.5% annual retail sales growth without energy efficiency. Energy efficiency impacts are modeled to ramp up from 0.25% in 2010 to 1.0% in 2013. Energy savings then increase annually at a rate of 2% of prior program year impacts. In 2015, for example, energy savings are 1.04% of retail sales, reducing annual retail sales growth to 0.46%.

[15] Wilson, J., "Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

[16] Chandler, S. and M.A. Brown, "Meta-Review of Efficiency Potential Studies and Their Implications for the South," Working Paper # 51 (August 2009). See also American Council for an Energy-Efficient Economy, "North Carolina's Energy Future: Electricity, Water, and Transportation Efficiency," Report Number E102, March 2010, p. 15 (finding that the "medium case" energy savings potential for utility-led energy efficiency programs is approximately 17% by 2025).

Figure 1: Energy Efficiency Savings Impacts of Duke, PEC, and Leading Utility

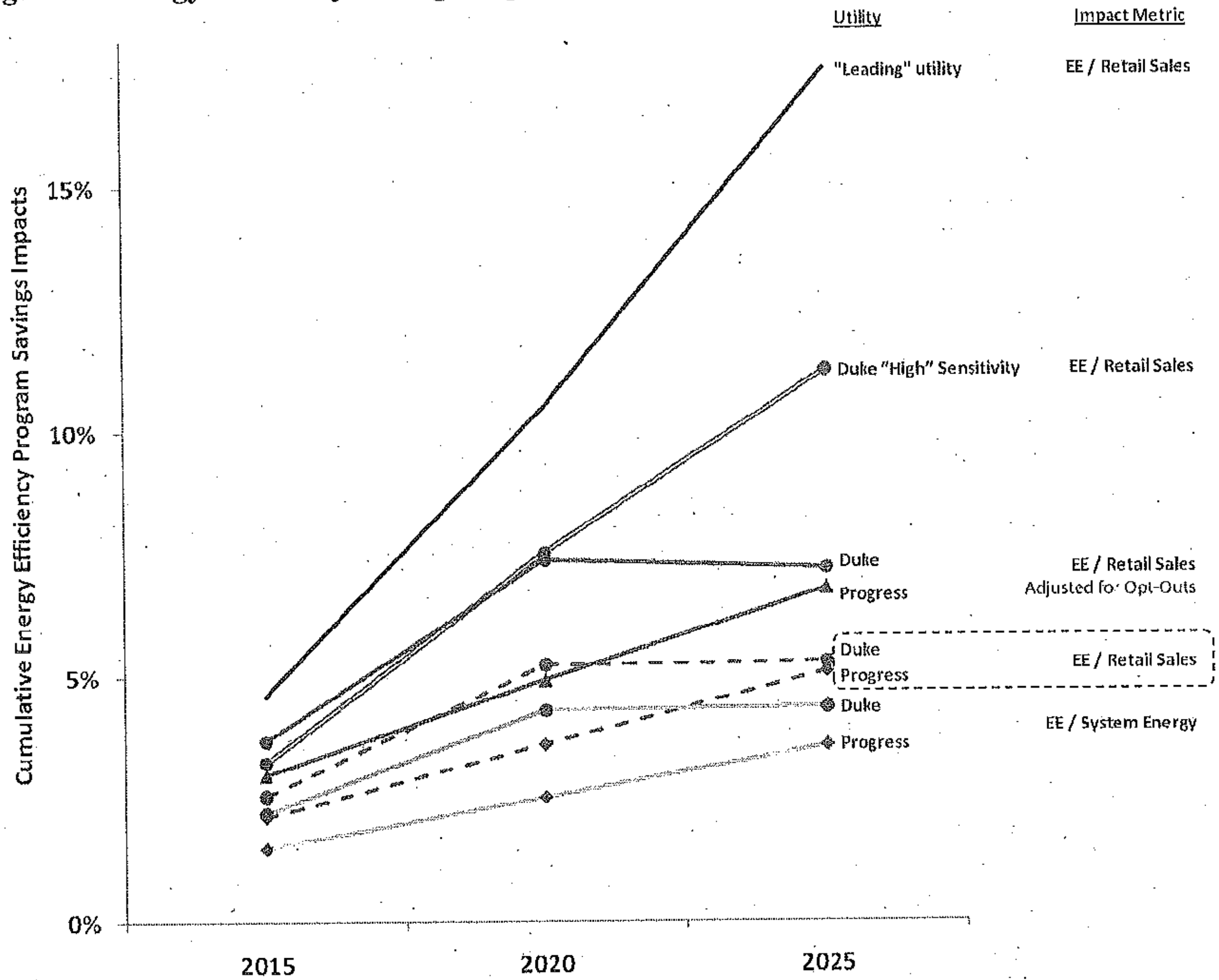

Figure 1 illustrates that Duke and PEC lag significantly behind the typical leading utility, regardless of which baseline they use. Figure 1 also shows that Duke's energy efficiency program impacts grow during the first decade, but level off in the second decade of the planning horizon. PEC does project growth in program impacts in its second decade, but only enough to make up for deficient growth in the first decade. As a result, while aggressive levels of energy efficiency may be sufficient to eliminate a large amount of load growth through about 2020, the North Carolina resource plans are both skewed towards unnecessary supply-side additions in the second decade of the planning period.

The remainder of this section addresses the ways in which Duke and PEC continue to underestimate the long-term potential of energy efficiency savings in their resource planning.

B. The industrial opt-out provision creates a lost energy savings opportunity.

Senate Bill 3 allows industrial customers that implement their own energy efficiency programs, "in accordance with stated, quantified goals for demand-side management and energy efficiency" to "opt out" of utility energy efficiency programs and not bear the costs of new programs along with other customer classes. N.C. Gen. Stat. § 62-133.8(f). The opt-out provision does not exempt industrial customers from engaging in energy efficiency efforts altogether; rather it allows these customers to implement their own energy efficiency programs. Based on the Duke and PEC resource plans, however, it appears that industrial customers are not achieving substantial energy efficiency savings on their own. For example, none of the energy forecast adjustments discussed by Duke on page 106 of its IRP reflect a significant increase in industrial energy efficiency efforts spurred by Senate Bill 3. Significantly, PEC excluded from its participation estimates ***all customers*** eligible to opt-out of DSM programs.[17]

PEC and Duke estimate cumulative savings from energy efficiency programs to be 4.9% and 6.2% of retail sales, respectively, over the next ten years, taking into account the impact of opt-outs. These figures underestimate the potential savings from energy efficiency. Utilities in other jurisdictions with similar opt-out provisions are projecting greater energy savings. Rather than shifting responsibility for energy efficiency from utilities to industrial energy customers, the opt-out provision seems to have resulted in a lost energy savings opportunity.

The significance of this lost opportunity is suggested in Duke's discussion of the cost difference between its "base" and "high" energy efficiency cases. Duke acknowledges that "the high energy efficiency sensitivity is cost effective if there is an equal participation between residential and non-residential customers" but that "[i]f a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective." Duke 2010 IRP at 95. Thus, if enough industrial customers participate in Duke's efficiency programs, Duke could reduce the long run cost of its resource plan by increasing energy efficiency from about 5% to about 11% and by reducing or delaying new supply-side resources. A recent presentation to the North Carolina Energy Policy Council suggests that the opt-out provision equates to about 4% of Duke's retail sales, which is less than the 6% implied by the difference between the "high" and "base" energy efficiency cases.[18]

If this interpretation is correct, the industrial and large commercial sector represents a large resource opportunity--more than half of the cost-effective energy efficiency potential—that is not anticipated to be utilized. Cost-effective industrial energy efficiency measures and practices could increase long term energy savings from the current 5% level to about 11%. An additional 800 MW of capacity savings could be achieved on the Duke system, with a similar amount of capacity savings on the PEC

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[17] ICF International, *Progress Energy Carolinas DSM Potential Study*, March 16, 2009, p. 2-13.

[18] Progress Energy and Duke Energy, "Overview of Energy Efficiency by N.C. Investor Owned Utilities," presentation to the North Carolina Energy Policy Council, April 29, 2010, Slide 16.

system.[19] Failure to utilize this resource opportunity results in increased system costs affecting all classes of customers.

Several steps could be taken to address the impact of industrial opt-outs. First, the electric utilities could, at their own initiative or at the direction of the Commission, improve the quality of their programs directed to large commercial and industrial customers. The increasing number of "opt-ins" indicates that the utilities have made some efforts in this regard. Second, the Commission or the utilities could initiate a process to enforce compliance with the opt-out requirements, i.e. ensuring that industrial customers who opt-out actually implement their own efficiency measures. Third, industrial customers or their trade associations could work to provide firmer estimates of their energy efficiency plans and projected impacts on energy use and demand. Fourth, utilities, industrial customers and others could work together to develop more attractive programs that address efficiency opportunities that are not currently well-addressed by the utilities or current self-initiated customer projects.

C. Neither Duke or PEC has used a complete energy efficiency resource analysis in developing its IRP.

The second major reason that the energy efficiency savings impacts projected by Duke and PEC in their IRPs fall short is that neither utility is using a comprehensive energy efficiency potential study in its resource planning process or a consistent standard in determining to what extent energy efficiency can be achieved.

Duke limits its program potential to the "economic potential identified by the 2007 market potential study." Duke 2010 IRP at 68. Duke Witness Richard Stevie testified in the proceeding on the 2008 and 2009 IRPs, however, that this study is "out of date" and that Duke is "continuing to look at additional programs" that were not analyzed in the potential study.[20] PEC limits its program potential to the "cost-effective, realistically achievable potential" in its "updated potential study." PEC 2010 IRP at E-7. While the scope of PEC's updated study does appear to be broader than the earlier version, it appears to suffer from the same fundamental shortcomings as the earlier study. For example:

- The potential study mentions that the findings were benchmarked against other utilities, but such benchmarking, if it has been done, has not been disclosed.
- Energy savings practices, measures and entire sectors remain excluded from the scope of study.
- It is not evident from the resource plan that PEC has yet made effective use of the insights offered by its consultant in the potential study. It does not appear that PEC has adopted some highly cost-effective programs and strategies included in PEC's market potential study, such as an ENERGY STAR Appliance program and certain non-residential incentive programs.

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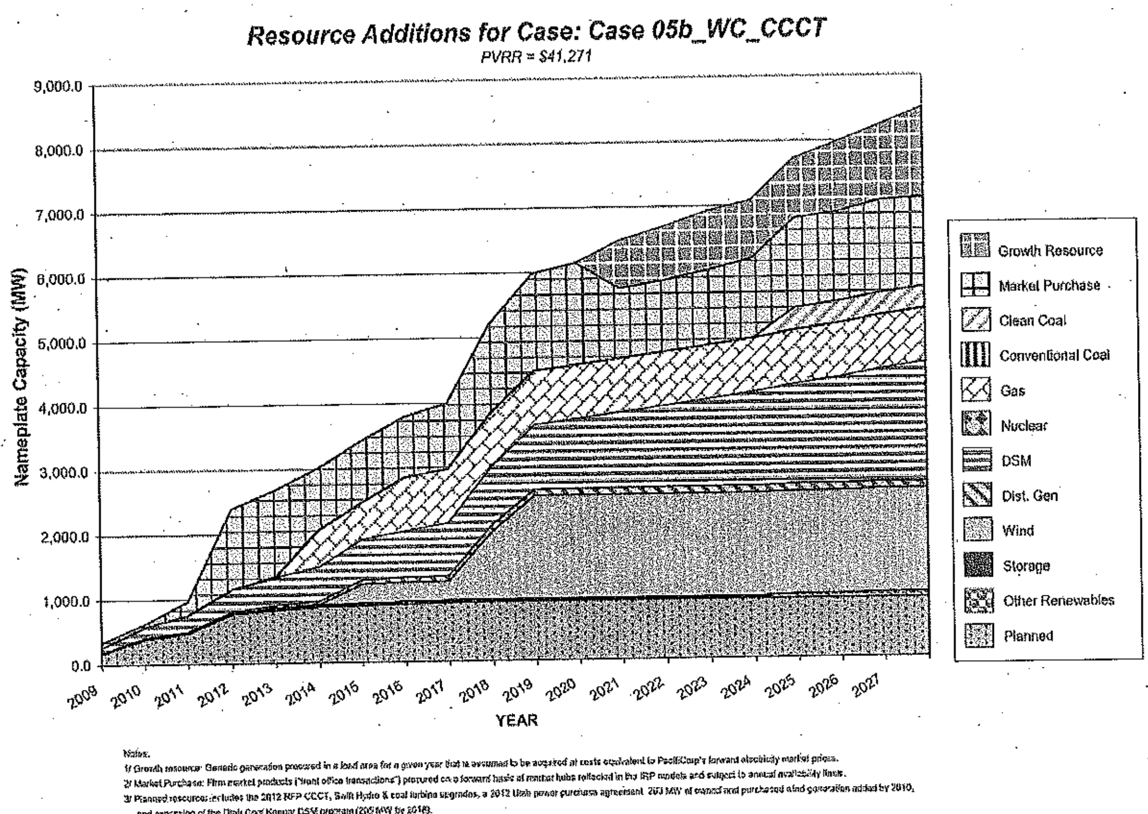
[19] PEC did not conduct any sensitivity analysis that might be used as a reasonable basis for an estimate.
[20] Transcript Vol. 4, pp. 31 and 39.

Further, PEC effectively assumes no further technological progress or development of new energy-saving practices. Duke is more confident about advances in efficiency, although this confidence is not fully reflected in its long-term resource plans.

SACE is unaware of any utility with a serious commitment to energy efficiency that assumes new energy efficiency opportunities will effectively cease to exist after a decade.[21] For example, the Northwest Power and Conservation Council concluded in a retrospective review that at least 85% of the projected 20 year energy savings in its first regional plan were realized.[22] Another example is illustrated in Figure 2, which shows the continued growth of the contribution of DSM resources to PacifiCorp's 2008 preferred resource portfolio. North Carolina utilities can and should rely on new technologies to provide additional cost-effective opportunities for efficiency in the outer years of the resource planning horizon.

Figure 2: PacifiCorp Preferred Resource Portfolio, 2008 IRP



PacifiCorp, *2008 Integrated Resource* Plan, May 2009, Volume I, p. 239 and Appendix A, p. 31.

[21] By "serious commitment," we mean a plan to achieve more than 3% energy savings over 10 years – a relatively low threshold.

[22] Northwest Power and Conservation Council, *Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*, Council document 2007-13, August 2007.

There are several steps that could be taken to help move North Carolina utilities toward a more complete energy efficiency analysis. First, the Commission could direct the utilities to conduct a comprehensive energy efficiency potential study. Such a study should be conducted without incorporating utility preferences regarding fairness and program design that constrain the findings; recognize the limitations inherent in such studies, particularly with respect to quantifying what is "achievable"; and make reasonable assumptions about long-term technological and program development prospects.

Second, the utilities could conduct more limited studies to address specific shortcomings, such as, the failure to study the transportation, communications and utilities sectors for energy savings opportunities. This would partially address the gaps in the existing studies and could lead more directly into program development.

Third, the Commission could recommend that the General Assembly establish a goal for energy efficiency based on evidence from leading efforts across the country. (The General Assembly could also direct the Commission to conduct such a process.)

D. Duke and PEC should adopt superior methods for valuing and considering energy efficiency resources.

A further reason that the Duke and PEC IRPs do not reflect the opportunity presented by energy efficiency is that they have not adopted resource planning practices that quantify the risk and cost implications of different levels of investment in energy efficiency resources. Duke's use of scenarios and sensitivities provides some guidance on these topics; however, the limited number and range of options considered (e.g., "high" vs. base) does not provide sufficient information to offer even a directional estimate of the price spike risk of different resource mixes. PEC offers no variation whatsoever in energy efficiency across its scenarios and sensitivities. As a result of failing to consider the full potential for energy efficiency resources, the resource planning approach used by Duke and PEC routinely includes higher costs and risks than would be the case if efficiency were treated as a resource on equal footing with other resource options.

E. Duke and PEC's analysis of energy efficiency as an adjustment to the load forecast does not allow the model to optimize cost-effective energy efficiency in portfolio outputs.

In their resource planning modeling, Duke and PEC integrate energy efficiency as a fixed model input, best characterized as a load adjustment. As a result, the resource planning model "works around" the limited efficiency input, selecting resources to meet the utility's adjusted load. While this treatment is appropriate for demand response, industry best practice is to treat energy efficiency as equal or even preferred to supply-side resources for planning purposes.[23]

[23] See, e.g., Aspen Environmental Group and Energy and Environmental Economics, Inc. (Aspen/E3), *Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term*

North Carolina utilities should use an approach that models energy efficiency as a resource, just as generating plants are modeled on the supply side. For example, the Northwest Power and Conservation Council has pioneered an approach that uses two supply curves for energy efficiency in the model that develops least-cost portfolios.[24] The use of two supply curves allows for different treatment of discretionary and lost-opportunity energy efficiency resources. Discretionary energy efficiency resources are investments that can be advanced or deferred based on near-term market decisions, such as a CFL market promotion. Lost-opportunity energy efficiency resources are programs that take advantage of opportunities due to market or customer circumstances, such as new construction and replace-on-burnout programs. Just as utilities use short-term market power purchases for different purposes than investments in new power plants, a sophisticated energy efficiency planning process distinguishes between discretionary and lost-opportunity resources. The load-adjustment approach used by Duke and PEC does not allow this distinction to be made.

Unless the General Assembly or the Commission establishes an aggressive energy savings target, we recommend that North Carolina utilities adopt a two-supply-curve approach to evaluate the energy efficiency resource in their IRP processes. At a minimum, the utilities should model energy efficiency on an equivalent basis to supply-side resources. This would be preferable to the "adjusted load" method that does not account for all cost-effective energy efficiency and therefore leads to resource portfolios with unnecessarily high levels of both cost and risk.

V. DUKE OVERSTATES ITS NEED FOR NEW CAPACITY.

A. Duke uses an unreasonably high 17 percent reserve margin.

Duke assumes a 17 percent reserve margin over the planning period in its assessments of its loads and resources and its need for new capacity. This reserve margin appears excessive when compared to reserve margins used by comparable utilities, such as PEC's 14-15 percent reserve margin.[25]

Duke has not shown that it needs a 17 percent reserve margin to ensure its ability to meet customer loads. In response to data requests, Duke did not provide any quantitative reliability analyses to support the use of such a high reserve margin. Instead, the Company merely referenced its historical reserve margins since August 2006 and a

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Procurement Planning in California: Final Report and Appendices, prepared for California Public Utilities Commission, April 2009, http://docs.cpuc.ca.gov/published/Graphics/103213.PDF

[24] Id. at 71.

[25] Duke's affiliates in Indiana and Ohio use 13.8 percent and 15.3 percent reserve margins. For example, see Duke Energy Ohio's October 7, 2010 *Revised 2010 Electric Long-Term Forecast Report and Resource Plan*, at pages 144 and 145. Dominion North Carolina Power uses the 15.3 percent reserve margin recommended by PJM to develop what it terms "an effective 11 percent" reserve margin. See *Dominion North Carolina and Dominion Virginia Power's Report of Its Integrated Resource Plan*, filed on September 1, 2010, at pages 4-3 and 4-4. SCE&G has determined that the appropriate level of reserves for its system is in the range of 12 percent to 18 percent. See *SCE&G's Integrated Resource Plan*, filed in South Carolina Public Service Commission Docket No. 2009-9-E in February 2010, at page 27.

number of narrative claims that it had presented on pages 62 and 63 of the IRP. Nor did Duke did provide any analyses that show that the "increased risks" cited on pages 62 and 63 of its 2010 IRP actually require a 17 percent reserve margin, as opposed to a 15 percent or lower reserve. Instead, the Company merely provided data to show the existing ages of its generating units, current resource mix and expected annual expenditure patterns for new generating units. This information may be relevant to an analysis of the level of reserves Duke needs, but it does not show that a 17 percent reserve margin is required.

In fact, PEC's system is subject to the very same "risks" that Duke cites at pages 62 and 63 of its 2010 IRP, yet PEC assumes a 14-15 percent reserve margin (that is, a 12-13 percent capacity margin) for its long-term planning assessments.[26] As PEC explained in its IRP:

> PEC reliability assessments have demonstrated that a minimum capacity margin of approximately 11-13% satisfies the one day in ten years LOLE criterion and provides an adequate level of reliability to its customers. PEC considers an 11% capacity margin to be a minimum and may be acceptable in the near term when there is greater certainty in forecasts. PEC uses a minimum capacity margin of 12-13% in the longer term to provide an extra margin of reserves to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delay in bringing new capacity additions on-line, and uses this criterion to determine the need for generation additions.

PEC 2010 IRP at 19.

Indeed, PEC is subject to the very same planning requirements (a one-day-in-ten-years loss of load probability) as Duke. Moreover, unlike Duke, in response to a data request, PEC was able to provide two reliability studies that formed the basis for its reserve requirements. PEC explained in its 2010 IRP that it is taking steps to improve the reliability and flexibility of its system:

> The addition of smaller and highly reliable CT capacity increments to the Company's resource mix improve the reliability and flexibility of the PEC fleet in responding to increased load requirements.... Each of the new combined cycle facilities will be equipment with bypass dampers to ensure that the plants can be operated in simply cycle or combined cycle mode to ensure reliability and operational flexibility.

PEC 2010 IRP at 19. The retirement of existing coal-fired units and the addition of smaller and flexible combustion turbine and combined cycle capacity should similarly improve the reliability and flexibility of Duke's system and, thereby,

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[26] As explained by PEC:
Capacity Margin = (Reserves/Total Supply Resources) times 100.
Reserve Margin = (Reserves/System Firm Load after DSM) times 100.

lower the required level of reserves and the required reserve margin. If Duke used a more reasonable reserve margin, it could significantly reduce the need for new capacity. The use of a 15 percent reserve margin would reduce Duke's need for capacity by approximately 400 to 450 MW each year during the planning period.

B. Duke treats demand response as a resource option with its own reserve requirement, rather than as a load adjustment.

Duke's PowerManager, Interruptible Power Service, and Standby Generator Control programs are all load curtailment programs design to reduce the Company's loads when required. See Duke 2010 IRP at 33. The appropriate treatment for such demand response programs when evaluating the Company's loads and resources and its need for new capacity is to use them to reduce the load side of the calculation. This is the methodology used by PEC in its 2010 IRP where it calculates its reserves, capacity margins and reserve margins on the basis of its firm loads after demand response. See PEC 2010 IRP at 23.

Duke, however, does not reduce its loads to reflect the demand response programs before it calculates its needed system resources. Instead, it applies its required 17 percent reserve margin to all of its loads (including those that will be curtailed under its demand response programs). Having determined its required resources (1.17 times the load), Duke then applies the demand response programs as a supply-side resource. The following table illustrates that the methodology used by Duke results in a need for more new capacity:

Table 4: Reserve Requirement Methodology

Reserve Requirement Method:	Duke	PEC*
Reserve margin	17%	17%
Total load**	1000	1000
Demand response as a reduction in load		75
Net load	1000	925
Required reserves	1170	1082
Current supply-side resources	1000	1000
Demand response as a supply side option	75	
Additional resources required	95	82
Percent of resource requirement related to applying demand response as a reduction in load	18%	

* The reserve requirement method used by PEC is shown using Duke's 17% reserve margin for illustrative purposes.

**The total system load is assumed to be 1000 MW in each instance.

The significance of Duke's approach is that Duke includes a reserve margin of 17 percent for all of its assumed loads, even those loads that will be curtailed by Demand

Response, when calculating the need for reserve and new capacity. Given that Duke currently assumes that its demand response programs will total some 1,267 each summer beginning in 2014, this means that the Company has included 215 MW of reserves attributable to these programs and, thereby, overstated its required reserves and its need for new capacity by these 215 MW in 2014 and each subsequent year during the planning period.

C. A significant portion of Duke's claimed need for new capacity resources is attributable to new wholesale loads.

A significant portion of Duke's resource needs are based on its wholesale power sale agreements, especially the new agreement to supply Central Electric Power Cooperative, Inc's supplemental resource needs of approximately 120 MW in 2013, increasing to 1000 MW by 2028. Duke 2010 IRP at 38. To the extent that these loads lead Duke to add expensive new capacity that it would otherwise not build or purchase, the costs of that new capacity should be borne by the wholesale customer(s) that created the need for it, not by Duke's captive retail customers.

VI. DUKE AND PEC DO NOT USE REALISTIC ASSUMPTIONS ABOUT COAL AND NUCLEAR GENERATION IN THEIR EVALUATION OF RESOURCE OPTIONS.

A. Both Duke and PEC acknowledge the inevitability of greenhouse gas regulation, but neither utility has shown in its 2010 IRP that it has a realistic plan for reducing its greenhouse gas emissions.

1. Duke projects that its GHG emissions will increase through 2030, but does not present a plan to reduce GHG emissions.

Duke acknowledges the risk that federal regulation will require reductions of greenhouse gas emissions. However, Duke does not present any evidence in its 2010 IRP that it has a realistic plan for reducing its greenhouse gas emissions during the planning period.

Duke recognizes that it is likely that Congress will adopt mandatory greenhouse gas ("GHG") emission legislation at some point, although the timing and details are highly uncertain at this time. Duke 2010 IRP at 47. Duke also recognizes that the U.S. Environmental Protection Agency ("EPA") is undertaking actions to regulate emissions of GHGs from new and modified major stationary sources, including power plants. Id. at 47-48. Moreover, the air quality permit for the new Cliffside Steam Station Unit 6 requires that Duke retire Cliffside Units 1-4, plus an additional 800 MW of coal-fired units located in North Carolina by the end of 2018. In addition, the air permit requires the company to take additional actions to render Cliffside Unit 6 carbon neutral by 2018, subject to Commission approval and "appropriate cost recovery." Nonetheless, Duke currently projects that its system carbon dioxide ("CO_2") emissions will ***increase*** between 2010 and 2030, whether it adds new nuclear units or just new natural gas-fired units. See Duke 2010 IRP, Figure A.4 .

It is not surprising that Duke is projecting that its annual CO_2 emissions will rise between 2010 and 2030. Even though Duke is planning to retire more than 1,600 MW of existing coal capacity, emissions reductions from those retirements will be more than offset by increased emissions from the new Cliffside Unit 6 coal plant. Cliffside Unit 6 will emit approximately six million tons of CO_2 each year, or more than two million tons of CO_2 per year than the 2008 CO_2 emissions from all of the coal units that Duke proposes to retire. In addition, Duke is planning to add more than 4,000 MW of new gas-fired combined cycle and combustion turbine capacity over the planning period. Although they emit significantly less per MWh than coal-fired facilities, gas-fired units do emit CO_2.

To actually reduce its annual CO_2 emissions, Duke will need to reduce its reliance on coal-fired generation by retiring additional coal units beyond those already proposed for retirement. Given that the Company already is planning to include new nuclear units in its future resource mix, the alternatives for displacing additional coal units are adding more energy efficiency and DSM, adding more renewable resources, and building more natural gas-fired combined cycle units.

Natural gas combined cycle generation has emerged as a viable, low-cost and lower risk alternative to coal. As Duke acknowledges in its 2010 IRP, recent assessments show that there is far more natural gas available in the domestic U.S., and at significantly lower prices:

> "There has been an extraordinary transformative shift in natural gas fundamentals over the past few years… Through trial and error, natural gas producers began to crack the code for finding and developing unconventional reservoirs like tight sands and shale. Through a variety of incremental improvements like horizontal boring, hydraulic fracturing and three-dimensional seismic imaging, the cost and yield curves for extraction from this unconventional gas source became more favorable. As incremental costs fell, improvements in resource characterization led to a dramatic rise in the estimated size of their reserve base. In June 2009, the U.S. potential gas committee released their biennial report for 2008 in which the committee raised their estimates of the size of U.S. gas reserves by 39% from their previous estimate.
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> The size of the North American reserve base alone will have a dramatic impact on the U.S. gas industry for decades and it will once again de-couple the US market from the broader global gas market. The impact on the electric utility sector will also be profound as this sector represents the single largest growth opportunity for the gas producers.

Duke 2010 IRP at 26-27.

Duke would not become unreasonably dependent on natural gas if it built more natural gas-fired combined cycle capacity to replace additional coal-fired capacity beyond the 1,600 – 1,700 MW that the Company currently is proposing to retire. First, it may not be necessary to replace coal-fired with gas-fired capacity on a MW for MW basis – in other words, some of the replacement capacity and energy should come from energy efficiency and renewable resources. Second, Duke is projecting that gas-fired units will provide about .4 percent of its needed energy in 2011, and only about ten percent of its needed energy in 2030, even with the approximately 4,000 MW of new combined cycle and combustion turbine capacity it is planning to add as part of its resource plan. See Duke 2010 IRP at 79. Thus, natural gas will not represent an unreasonable portion of the Company's energy mix even if more combined cycle units are added to replace retired coal units and/or Duke's proposed nuclear plants.

The Commission should require Duke to present a plan for actually reducing its CO_2 emissions over the planning period. Based on the legislation that has been introduced in Congress and statements from the current Administration, the plan should have the goal of reducing Duke's annual CO_2 emissions by approximately 14 to 20 percent by 2020 and by approximately 40 percent by 2030.

2. <u>PEC has not included a projection of GHG emissions in its resource plan, let alone a plan to reduce GHG emissions.</u>

Like Duke, PEC recognizes that it is likely that Congress will adopt mandatory GHG emission legislation at some point and that EPA is undertaking actions to regulate emissions of GHGs from power plants:

> Even though at the time of this filing there appears to be a temporary loss in legislative momentum with respect to climate change it is widely assumed there will ultimately be legislation of some form resulting in a mandate to reduce the carbon output from the Company's generation fleet. This potential legislation paired with proposed and expected EPA regulations regarding greenhouse gas emissions led to the Company's decision to retire three coal units at each of its Lee and Sutton facilities and construct new state of the art efficient natural gas combined cycle units at those sites.

PEC 2010 IRP at page 3. Despite this acknowledgment, PEC provides no evidence in its 2010 IRP that its proposed resource plan (or the two alternatives it considered) actually will result in any, let alone significant, reductions in the greenhouse gas emissions from the Company's generation fleet. Unlike Duke, PEC does not even include a figure in its IRP showing the trajectory of future annual CO_2 emissions under its proposed and alternative resource plans.

In fact, although PEC is proposed to retire 1,500 MW of its existing coal-fired units, it is planning to replace those retired units with 1,500 MW of state-of-the-art gas-fired generation. PEC 2010 IRP at 3. Although natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, the new state-of-the-art gas units being added by PEC can be expected to operate more often than the coal units slated for retirement have operated in recent years, especially given projected low natural gas prices. This means that it is possible that the Company's replacement of existing coal by new gas combined cycle units may not result in any significant reduction(s) in PEC's system CO_2 emissions. At the same time, the Company's proposed resource plan will add thousands of MWs of additional combined cycle and combustion turbine capacity during the 2010 to 2030 planning period. As a result, it is reasonable to expect that the Company's annual system CO_2 emissions will not go down much, if at all during the planning period.

B. Both Duke and PEC have prudently decided to retire their existing unscrubbed coal units, but neither utility shows in the IRP that continued operation of their scrubbed coal units is economical.

In addition to climate change legislation, existing coal-fired units face an array of regulatory risks that will require capital investments and increased operating expenses, including new EPA air quality regulations, regulations under Section 316(b) of the Clean Water Act, new steam electric effluent guidelines and new coal combustion waste regulations. PEC describes the regulatory risks facing its coal-fired units in Appendix F to its IRP. Duke discusses these legislative and regulatory issues and risks facing the Company's coal-fired units at pages 43 to 49 of its 2010 IRP. Even existing coal units with SO_2 scrubbers face many of the same issues and risks as the unscrubbed units that Duke and PEC are planning to retire, including the need to further reduce their emissions of mercury and other hazardous air pollutants or the need to convert from once-through to closed-cycle cooling.

Duke currently owns approximately 7,650 MW of coal-fired facilities in North and South Carolina. Duke 2010 IRP at 17-22. The Company is currently planning to retire 800 MWs as a condition of the air permit for the new Cliffside Unit 6 coal plant. The Company also assumes for planning purposes in its 2010 IRP that all of its remaining coal units without SO_2 scrubbers will be retired by 2015, although Duke allows itself some flexibility in terms of the specific units to be retired and/or their exact retirement dates. Duke 2010 IRP at 60.

PEC currently owns approximately 5,200 MW of coal-fired facilities in North and South Carolina. PEC 2010 IRP at B-1. The Company is currently planning to retire 1,500 MWs of unscrubbed coal at the beginning of 2015 although, like Duke, PEC allows itself some flexibility in terms of the specific units to be retired and/or their exact retirement dates. Id. at 3. The Company also said that it is continuing to evaluate the "best course of action" with regard to its South Carolina Robinson coal plant.

However, neither Duke or PEC presents in its 2010 IRP any specific analysis of the risks faced by its existing scrubbed coal plants, any assessment of what controls will be needed to be added at each of these units, or whether it will be more economic to add such needed controls than to retire the unit(s). This is a serious flaw. Duke's responses to a SACE data request reveal that the Company has prepared some analyses of the costs of adding controls to some of its coal units with SO_2 scrubbers that it does not currently plan to retire. PEC also provides in response to a data request several studies of the cost and economics of retiring some of its older coal units. In addition to showing that retirement of the units at Cape Fear and Weatherspoon is the more economic option, these studies also showed that retirement of the Robinson coal plant by 2014 is the more economic option in almost all of the scenarios studied.[27] The analyses prepared by Duke

[27] *Small Unit Continued Operation v. Retirement*, provided in PEC's response to Item 1-2 of SACE's Data Request No. 1.

and PEC should be presented to the Commission in the companies' IRPs to allow the Commission and other parties a full opportunity to review and critique them. In addition, PEC should analyze the economics of the retirement versus continued operation of each of the existing coal units that the Company is not currently planning to retire in the near future.

C. The assumptions made by Duke and PEC about the timing of new nuclear units are unrealistic.

Duke provides a schedule that has the Lee Station Unit 1 nuclear unit starting operations in the first quarter of 2021, with Unit 2 starting commercial operations in the first quarter of 2022.[28] This schedule is very aggressive, including, for example an extremely short period (48 months) between the placement of the first nuclear island concrete in the third quarter of 2016 and fuel loading in the third quarter of 2020. PEC also assumes that new nuclear capacity will be available in the region by 2020-2021. In two of the three alternative resource plans that it examined, PEC makes the extremely optimistic assumption that it would be able to own 25 percent shares of two new Advanced Light Water Reactors ("ALWR") that would begin commercial operations in 2020 and 2021. <u>See</u> Figure A-3 on page A-5 of PEC's 2010 IRP.

The assumptions by Duke and PEC that new nuclear capacity could be brought online in the 2020-2021 should be viewed as highly uncertain, for several reasons:

- All of the Advanced Light Water Reactor designs currently being considered for construction in the region (including the AP1000 design being considered by Duke, SCE&G and Southern Company) are untested designs – design certification by the Nuclear Regulatory Commission ("NRC") does not guarantee that the total plant design will be without flaws or that significant problems will not be experienced during construction.
- It is uncertain when the NRC actually will issue the Combined Construction and Operation License for the Lee Nuclear Station or other nuclear power plants in the region and, consequently, when major construction actually will begin.
- Supply chain bottlenecks or constraints may lead to longer than expected lead times for critical plant equipment or there may be transportation-caused delays in shipping, especially if there are multiple nuclear construction projects in the U.S. competing for limited engineering and construction resources and for limited equipment manufacturing capacity.
- The history of large construction projects suggests that significant delays will be experienced, especially for new technologies.

[28] Duke also assumes that it could add substantial amounts of new nuclear capacity as early as 2016 and 2017 in at least one of its sensitivity analyses. This is a completely unrealistic schedule, as the Company does not even plan to begin site preparations at the Lee Nuclear Station until perhaps 2014.

In reality, no new generation nuclear plants have achieved such short construction schedules. The Olkiluoto 3 power plant in Finland was the first truly "new generation" nuclear unit to begin construction.[29] Construction began in 2005 with a scheduled completion date of 2009, but Olkiluoto has experienced many problems. Indeed, it is reported that completion of the plant is currently scheduled for the end of 2012, with a start of operations in early 2013 and that the projected cost of the plant has increased by more than 70 percent or about $4 billion.[30] A second EPR project has been under construction in France for several years and has also experienced construction and schedule problems.[31] The plant began construction in 2007 with an expected construction duration of 54 months. In 2010, the plant's owner, EDF, announced that the estimated cost of the project had increased by 50 percent to 5 billion euros and that the start of commercial operations had been delayed until 2014.[32]

PEC has stated that it will not build any new nuclear power plant(s) until after 2025. This appears to be a more conservative schedule than assuming 2020 or 2021 in-service dates for new regional nuclear units.

D. The cost of new nuclear units will likely be significantly higher than either Duke or PEC has assumed in its resource planning analyses.

Duke assumes that the cost of building twin AP1000 nuclear units at the proposed Lee Nuclear Station site in South Carolina will cost eleven billion dollars ($11 billion) in 2010 dollars. PEC assumes that the cost of building twin AP1000 nuclear units will cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in 2010 dollars. Even if Duke and PEC have correctly estimated the "overnight" cost of new nuclear units, when financing costs and the impacts of inflation are added, the total cost of a two-unit nuclear plant could reach or exceed [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].

Neither Duke nor PEC has provided, either in its IRP or in response to a data request, any supporting evidence or documents that form the basis for the cost estimate. There are a number of factors for the great uncertainty regarding the ultimate construction cost of Duke's proposed Lee Nuclear Station or any new nuclear power plants in the region:

- Construction cost uncertainty represents the most significant risk for a new nuclear power plant -- no nuclear power plant with an AP1000 design has been constructed, let alone operated, anywhere in the world. Without such actual experience, the estimated costs of proposed units such as the Lee Nuclear Station are highly uncertain. The actual costs of the existing

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29 Olkiluoto 3 is a European Pressurized Water Reactor ("EPR") design.

30 http://www.world-nuclear-news.org/NN-Startup_of_Finnish_EPR_pushed_back_to_2013-0806104.html

31 For example, see "Regulator stops flow of concrete at Flamanville," *Nuclear Engineering International*, June 18, 2008, at page 4.

32 "French Nuclear Watchdog Says EDF Has Problems With Flamanville EPR Liner" http://www.bloomberg.com/news/2010-08-30/edf-has-welding-problems-at-flamanville-epr-reactor-french-watchdog-says.html (Retrieved 31 August 2010).

generation of nuclear power plants were, on average, between two to three times the costs that were estimated during licensing or at the start of construction. And this does not include the experiences of most of the most expensive nuclear power plants like Plant Vogtle Units 1 and 2 whose actual costs were more than ten times the initial cost estimated by Georgia Power.

- As noted above, the first two reactors with advanced designs, Olkiluoto 3 and Flamanville are under construction in France. The first AP1000 project to actually begin construction is in China and has a scheduled completion date of late 2013. Currently unanticipated problems may be experienced during the construction or initial operation of this project or of the other initial AP1000 plants that will require extensive, expensive and time-consuming modifications to the design of the Lee Nuclear Station. Indeed, one clear lesson from the existing generation of nuclear power plants is that significant problems may be discovered during construction, startup testing or operations of new units that will require modifications and, consequently, increased costs at other plants with the same or similar designs.

- There is only a very limited track record for building any nuclear plant with a new generation nuclear technology. In fact, the recent construction experiences of nuclear plants under construction in Europe with untested new generation designs suggests that the actual cost of building the Lee Nuclear Station may be significantly higher than Duke now acknowledges and that construction may take substantially longer than the Company now predicts.

- There is a reduced infrastructure in the U.S. for building new nuclear power plants: many experienced construction workers have retired and have been replaced with new, less experienced workers – this may lead to reduced labor productivity; there are fewer workers with the specialized skills required for building new nuclear power plants; suppliers who provided nuclear quality equipment and materials during the construction of the existing generation of nuclear plants no longer do so; as a result there is a tight supply chain with potential bottlenecks.

Until the 1970s, building new nuclear power plants appeared to be a relatively low risk investment because construction and operating costs were relatively stable and easy to predict. However, starting in the 1970s, the costs of building new nuclear power plants began to spiral out of control. As a result, the actual costs of new plants were two to three times higher than the costs that had been estimated during licensing or at the start of construction. Consequently, the nuclear industry has a very poor track record in predicting plant construction costs and avoiding cost overruns. Indeed, as shown by data in a study by the Department of Energy, the actual costs of 75 of the existing nuclear power plants in the U.S. exceeded the initially estimated costs of these units by over 200 percent. The following table shows the overruns experienced by these 75 nuclear plants by the year in which construction of the nuclear power plant began.[33]

Table 5: U.S. Nuclear Plant Cost Overruns

Projected and Actual Construction Costs for Nuclear Power Plants

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.
The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.
Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.
b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

The **average cost overrun** for these 75 nuclear units was **207** percent. In other words, the actual average cost of the plants was about triple their estimated costs. In fact, the data in the previous table understates the cost overruns experienced by the U.S. nuclear industry because (1) the cost figures do not reflect escalation and financing costs, and (2) the database does not include some of the most expensive nuclear power plants built in the U.S. – e.g., Comanche Peak, South Texas, Seabrook, and Vogtle. For example, the cost of Plant Vogtle Units 1 and 2 increased from $660 million to $8.7 billion in nominal dollars – a 1,200 percent overrun.

Based on the industry's demonstrated failure to accurately project nuclear plant costs, any new estimates must be assessed with a great deal of skepticism and should be considered to be very uncertain. Duke argues that the range of uncertainty for the cost of the Lee Nuclear Station is only within a range of +20 percent to -10 percent. Duke has said that the recent experience in China and at the two plants in the Southeast (Vogtle and Summer), as well as the recent trend in industry data of lower escalation rates support its cost estimates and the +20%/-10% sensitivities used in our IRP analyses." (Duke

[33] This table was taken from the May 2008 report by the Congressional Budget Office, *Nuclear Power's Role in Generating Electricity,* at page 17.

Response to DR SACE 35). It is unclear what range of uncertainty for the cost of nuclear power plants PEC used in its resource planning or, indeed, whether PEC assumed any uncertainty in the cost of a new nuclear power plant.

However, there is only a few years' worth of construction experience at the AP 1000 plants being built in China – plus there is no evidence that the plants in China are being built to the strict standards required in the U.S. Moreover, the labor force and labor work conditions and compensation are very different in China than in the U.S. Altogether, this means that the China construction experience should not be relied upon as evidence that Duke's construction cost estimate is reasonable or is subject to only a minimal amount of escalation as licensing and construction proceed.

At the same time, there has been absolutely no construction experience at the AP 1000 units that Georgia Power and SCE&G are proposing to build. In fact, these units have not even received their Combined Construction and Operation Licenses from the NRC. Thus there is no experience that can give any comfort or assurance regarding the cost and schedule of the Lee Nuclear Station.

Finally, it is correct that nuclear construction costs declined somewhat after 2008. But this can be attributed to the worldwide economic downturn. As the economy improves, it is reasonable to expect the nuclear construction costs again will rise, perhaps as dramatically as before 2008, as nuclear, fossil-fired and renewable power plants and other infrastructure projects around the world compete for design and construction resources. Indeed, a July 2, 2010 e-mail on the subject of "Duke's Nuclear History" from Jim Turner (who was Duke's Group Executive Vice President and Chief Operating Officer until the end of January 2011) to Duke Energy CEO Jim Rogers and other members of Duke's Executive Staff recommended that the Company assume and plan that the cost of proposed nuclear plants could be 40 percent to 50 percent higher than Duke currently assumes:

> Obviously, the "design it once, build it many times" philosophy that underpins the AP 1000 design substantially reduces the likelihood of overruns in the 340% to 450% range, but it is not unreasonable to assume and plan for costs to be as high as 40%-50% above current estimates (see Cliffside and Edwardsport).

Attachment 3.

It is reasonable to expect that the industry will experience significant cost overruns if it builds new nuclear power plants in the United States. Given the industry's poor track record in estimating plant costs and the substantial uncertainties associated with building new nuclear power plants, it is reasonable to expect that the actual costs of new plants, like the Lee Nuclear Station, will be much higher than the industry now claims. At the same time, it does appear that the nuclear industry has learned some important lessons from the problems experienced during the building and operation of the existing generation of nuclear power plants and, therefore, can be expected to avoid some of those problems.

Even a 50 percent cost increase, as Mr. Turner suggests in his July 2, 2010 email would be reasonable to expect, would mean that new plants like the Lee Nuclear Station would be extremely expensive, perhaps costing as much as $25 billion, or more, just for two nuclear units. Such an increase of only 50 percent would be substantially below the 200 percent to 300 percent overruns that the industry experienced in building the nation's existing nuclear power plants.

VII. DUKE AND PEC HAVE NOT EVALUATED RENEWABLE RESOURCES BEYOND MINIMUM REPS COMPLIANCE.

PEC and Duke primarily evaluate renewable energy resources in the context of minimum compliance with the Renewable Energy Portfolio Standard ("REPS"). Renewable energy potential is barely varied among the strategies considered in the 2010 resource plans proposed by Duke and PEC. One exception to this limited perspective is that both utility plans discuss offshore wind development, which is likely to require more than a decade to develop. North Carolina utilities are prudently evaluating this resource in order to determine the appropriate development path in light of its resource characteristics and forecast system resource needs. SACE is engaged in similar research in cooperation with several states and the U.S. Department of Energy.

PEC and Duke should consider future investments beyond the minimum REPS requirements. Because development of on-system renewable energy resources is not required beyond 2020, these resource options should be evaluated in comparison to "traditional" resource options.

Additionally, Duke and PEC should conduct an analysis of the potential ancillary benefits or costs of integrating significant levels of on-system renewable energy resources, including:

- The potential benefits regarding grid stability;
- The potential efficiency gains in transmission and distribution associated with higher levels of distributed generation; and
- The reduced costs associated with greenhouse gas and air pollutant mitigation.

Duke and PEC assume that the benefit of renewable energy resources is limited to about 5 - 7 cents per kWh (avoided costs), which seems to be an underestimate. Moreover, these utilities spend about twice this amount to build and operate baseload, intermediate or peak power plants.

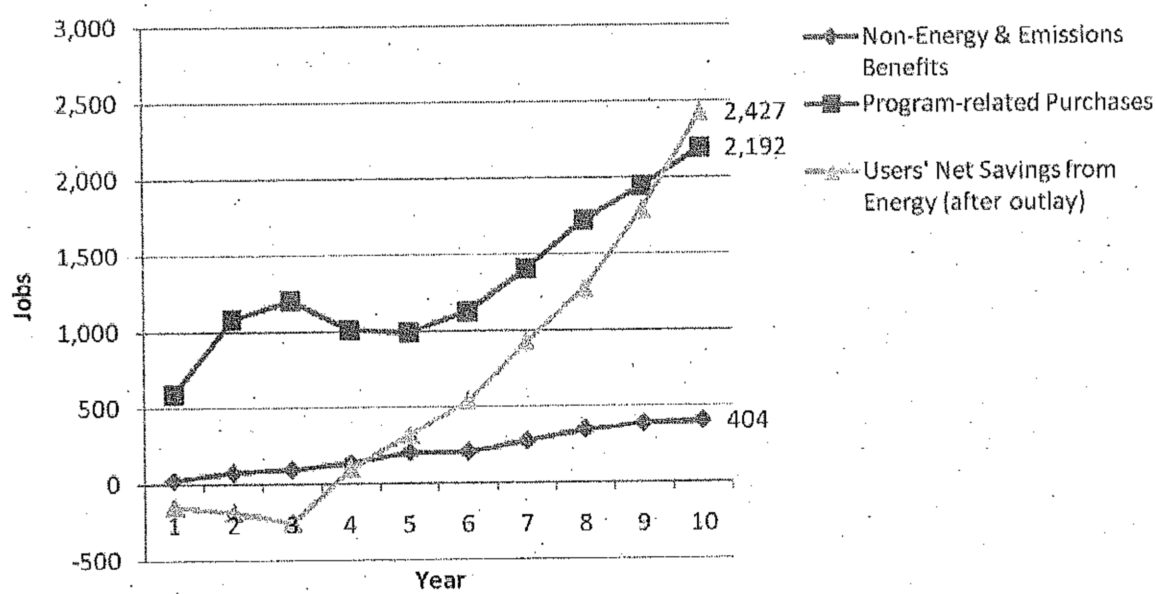
VIII. MODELING OF ECONOMIC IMPACTS WOULD INFORM THE EVALUATION OF RESOURCE PORTFOLIOS.

Several major utilities across the country perform modeling and analyses to understand the economic impacts of their resource planning decisions. While this economic analysis is not required in North Carolina, information about economic impacts would assist electric utilities, the Commission and interested parties in understanding the broader implications of the utilities' resource planning decisions.

North Carolina utilities should consider using the REMI Policy Insight model, a highly regarded tool for conducting economic impacts analyses of resource planning portfolios. EPA has called the REMI Policy Insight model the "most sophisticated" approach for conducting economic analysis of energy policies or projects.[34]

A 2010 study on Wisconsin's energy efficiency and renewable energy programs provides a good example of how the REMI Policy Insight model can be used to cover "all aspects of changes in the economy," including changes in business sales, gross regional product, real after-tax income, and jobs.[35] In that study, the REMI model showed various economic development impacts of efficiency and renewable energy programs, including lower energy costs, increased "business competitiveness," and a lower cost of living, which in turn increased the attractiveness of the state as a place to live and work.[36] Figure 3 shows estimates of the impacts of energy efficiency and renewable energy programs on jobs.

Figure 3: REMI Model Estimates of Employment Impacts for Focus on Wisconsin Programs



Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Wisconsin, March 2, 2010.

North Carolina utilities should consider using the REMI Policy Insight model, in accordance with best practices, to estimate the economic impacts of resource options.

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[34] U.S. Environmental Protection Agency, *Assessing the Multiple Benefits of Clean Energy: A Resource for States*, Climate Protection Partnerships Division. EPA also has noted that REMI Policy Insight model must be used with care so as to avoid unreliable findings, as seen in the Tennessee Valley Authority's draft resource planning documents recently presented for public comment.

[35] Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Wisconsin, March 2, 2010.

[36] Id.

IX. PROCEDURAL RECOMMENDATIONS

Pursuant to Commission Rule R8-60(j), an evidentiary hearing to address issues raised by the Public Staff or other intervenors regarding the utility IRPs may be scheduled at the discretion of the Commission, with the scope of any such hearing to be limited to such issues as identified by the Commission. SACE requested an evidentiary hearing on issues to be identified by the Commission along with its petition to intervene filed on December 13, 2010. Intervenor NCWARN made a filing on December 17, 2010 supporting that request. In a filing on December 28, 2010, PEC stated that it did not oppose such a request, but moved the Commission to delay ruling on the request "until SACE and NC WARN have been required to identify the elements of the electric suppliers' IRPs with which they disagree and provided the basis for such disagreement."

Undersigned counsel has discussed this issue with counsel for PEC and Duke and agrees that a hearing would be more productive and a more efficient use of the Commission's time and resources if the issues for hearing are clearly identified in advance. SACE has attempted to raise and discuss a limited number of significant issues in the foregoing comments, and respectfully submits those issues for the Commission's consideration as possible issues on which it may wish to receive pre-filed witness testimony and conduct a hearing.

Alternatively, if the Commission elects not to schedule an evidentiary hearing on the utility IRPs, SACE recommends that the Commission consider convening a workshop on a limited set of issues. Such a workshop could provide an opportunity for the electric utilities to present their IRPs, and for intervenors to present their analysis of those IRPs, to the Commission, and for the Commission to question the parties' representatives on the issues it identifies, without the need for formal witness testimony. In addition or in the alternative, the Commission may wish to consider establishing a collaborative workgroup to discuss and report on certain issues related to the IRPs and the resource planning process. SACE respectfully suggests that such a workgroup would be more effective if it continued to meet after the conclusion of the present docket, so that the workgroup's suggestions and recommendations could inform the utilities' development of the 2011 annual reports and 2012 biennial reports. To enable the full participation of the Public Staff, the Commission may wish to engage a third-party facilitator if it decides to convene such a workgroup.

Respectfully submitted this 10th day of February, 2011.

Gudrun

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CERTIFICATE OF SERVICE

I certify that the persons on the service list have been served with the Public Version of the Initial Comments of Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 10th day of February, 2011.

Robin Dunn

Robin Dunn

Duke "High DSM" Portfolios Cost Less than "Base DSM" Portfolios [CONFIDENTIAL INFORMATION REDACTED]

Year	Selected "Base DSM" Portfolios					Selected "High DSM" Portfolios				
	CT/CC	2N 2021-2023 ("Optimal Plan")	2N 2026-2028	1N 2022	1N 2027	HDSM Gas	HDSM 1N 2022	HDSM 1N 2027	Clean Energy Gas	Clean Energy Nuclear
2011-16										
2017	CC	CT	CT	CT	CT					
2018						CC	CC	CC		
2019	CT	CT	CT	CT	CT				CC	CC
2020						CT	CT	CT	CT	CT
2021	CC	N	CC	CT(PPA)	CC					
2022				N			N			N
2023	CC	N	CC		CC	CC		CT	CC	
2024				CC						
2025	CC		CT(PPA)		CC	CT				
2026	CC		N	CC				CT(PPA)		
2027		CC			N		CT	N		
2028	CT		N	CC		CC			CT	CT
2029		CC			CT					
2030	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT
Total CT	2,050 MW	1,780 MW	1,780 MW	2,220 MW	2,240 MW	1,890 MW	2,070 MW	2,070 MW	1,690 MW	1,880 MW
Total CC	3,250 MW	1,300 MW	1,300 MW	1,950 MW	1,950 MW	1,950 MW	650 MW	650 MW	1,950 MW	650 MW
Total Nuclear	-	2,234 MW	2,234 MW	1,117 MW	1,117 MW		1,117 MW	1,117 MW	-	1,117 MW
Total Nuclear Uprate	204 MW	205 MW	206 MW	209 MW	210 MW	210 MW	211 MW	212 MW	207 MW	208 MW
Total Retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW
Total DSM	1,900 MW	1,900 MW	1,900 MW	3,188 MW	1,900 MW	3,188 MW	3,188 MW	3,188 MW	1,900 MW	3,188 MW
Portfolio NPV Costs ($million)										
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NPV Cost Difference ($billion)										
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Attachment 1

From: Turner, Jim
To: Rogers, Jim; Executive Staff
CC: Currence, Kathy K; Toney, BT
Sent: 7/2/2010 9:20:05 AM
Subject: RE: Duke's nuclear history

[redacted] Obviously, the "design it once, build it many times" philosophy that underpins the AP 1000 design substantially reduces the likelihood of overruns in the 340% to 450% range, but it is not unreasonable to assume and plan for costs to be as high as 40%- 50% above current estimates (see, for example, Cliffside and Edwardsport).

[redacted]

Attachment 3