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February 5, 2013

VIA HAND DELIVERY

Ms. Gail Mount
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 - 2012
Docket No. E-100, Sub 137

Dear Ms. Mount:

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

- An original and 17 copies of the Initial Comments of Sierra Club and Southern Alliance for Clean Energy (**Confidential Version**). ***This document contains confidential data and should be filed under seal.*** The confidential information is indicated by gray shading in the text of the comments.
- An original and 15 copies of the Initial Comments of Sierra Club and 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 and serving a copy of the Confidential Version on counsel for Duke Energy Carolinas and Progress Energy Carolinas. 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

PUBLIC VERSION—CONTAINS REDACTED INFORMATION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 137

In the Matter of:	)	
	)	**INITIAL COMMENTS OF**
Investigation of Integrated Resource	)	**SIERRA CLUB AND SOUTHERN**
Planning in North Carolina – 2012	)	**ALLIANCE FOR CLEAN ENERGY**
	)	

PURSUANT TO North Carolina Utilities Commission Rule R8-60(j) and the Commission's January 15, 2013 Order Establishing Date for Comments on Integrated Resource Plans and Related REPS Compliance Plans, intervenors Southern Alliance for Clean Energy ("SACE") and the Sierra Club, through counsel, file these initial comments on the 2012 Integrated Resource Plans ("IRPs") of Duke Energy Carolinas, LLC ("DEC") and Progress Energy Carolinas, Inc. ("PEC").

I. SUMMARY

In certain key respects, the DEC and PEC 2012 IRPs improve upon the companies' previous IRPs. Noteworthy improvements include the following:

- DEC significantly increased its "High EE/DSM Case," as compared to its 2011 IRP, to reflect higher levels of energy efficiency.
- For the first time, PEC analyzed a high energy efficiency case, which would lower total system costs by more than $4 billion compared to PEC's "preferred resource plan." PEC's base energy efficiency case also includes greater levels of energy savings than in its 2011 IRP.
- Both companies' EE programs are performing well, saving significant amounts of energy—and saving customers money—in a cost-effective manner.
- Both companies' experience with REPS compliance, and DEC's internal analysis, demonstrates that renewable energy resources are available and can be deployed at a reasonable cost.

- Based on studies ordered by the Commission, both companies have revised their reserve margins to more reasonable levels, which could defer or eliminate the need for new power plants.

- Both companies plan to retire their oldest, dirtiest coal units, which will reduce cost and risk to customers.

Notwithstanding these key improvements, each company's IRP suffers from flaws that result in a "preferred plan" that is more costly, more risky, and has greater environmental impacts than would be a plan based on robust assumptions and developed according to best practices. To correct these flaws, SACE and the Sierra Club recommend that DEC and PEC implement the following improvements:

- DEC and PEC should include significantly more energy efficiency in their preferred resource plans, to offer customers lower costs and lower risks;

- DEC and PEC should evaluate energy efficiency using an approach equivalent to the approach used for supply-side resources;

- DEC and PEC should improve their energy efficiency forecasting and pursue additional opportunities to grow the efficiency resource in the long term;

- DEC and PEC should evaluate and include in its IRP analysis the potential for increased levels of renewable energy resources beyond minimum REPS compliance to help meet customers' energy and capacity needs and moderate regulatory risk, and PEC should develop a long-term plan to grow renewable resources;

- DEC and PEC should each conduct, and explicitly address in their IRPs, a rigorous evaluation of the economics of continuing to operate scrubbed coal units;

- DEC should align its treatment of demand response, namely the unnecessary requirement for backstand reserves, with that of PEC, thus reducing its reserve margin;

- Each company should conduct a more complete evaluation of the risks of construction delays and cost increases associated with new nuclear generation, using robust assumptions; and

- Each company should evaluate the macroeconomic impacts of its resource portfolios.

Given that the companies intend to harmonize their resource planning practices in the wake of the Duke Energy-Progress Energy merger, the 2013 IRP cycle is a critical opportunity to implement these recommendations.[1]

II. LEGAL FRAMEWORK

N.C. Gen. Stat. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current" an analysis of the State's long-range needs for electricity. 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.* As the Commission has explained,

> Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

North Carolina Utilities Commission, Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina (November 7, 2012).

[1] In its IRP, PEC states that, in light of the Duke-Progress merger, DEC and PEC intend to "standardize data inputs and models for use in their individual IRP filings" and that "[a]s more coordinated planning occurs over time, future IRPs will reflect the effects of coordinated assumptions and analytic approaches between DEC and PEC." PEC 2012 IRP at 3.

In furtherance of these requirements, the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires each electric utility to file a biennial report of its integrated resource planning process in even-numbered years, and in odd-numbered years, an annual report updating its most recent biennial report. 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 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).

III. DEC'S AND PEC'S IRP MODELING SHOWS THAT THE UTILITIES COULD SAVE CUSTOMERS MONEY AND LOWER RISK BY INCREASING LEVELS OF ENERGY EFFICIENCY IN THEIR PLANS.

DEC's and PEC's 2012 portfolios show that resource plans with more aggressive—but still achievable—levels of energy efficiency would save ***roughly $9 billion*** across the merged Duke Energy's Carolinas service territory as compared to each company's "preferred" plan. Furthermore, data supporting both IRPs shows that incorporating the utilities' High Energy Efficiency/Demand Side Management ("High EE/DSM") cases have lower risk than does any portfolio using base case EE/DSM assumptions. Thus, a resource plan that includes the "the least cost mix" of resource options, as required by North Carolina law, and reduced risk of cost increases should include more aggressive levels of energy efficiency than DEC and PEC present in their 2012 plans. Increased levels of energy efficiency lower total system costs.

The DEC and PEC 2012 IRPs include quantitative analyses showing that ***portfolios with High EE/DSM resources cost $9 billion less than the "preferred plans" selected by DEC and PEC over the full analysis time frame***, as illustrated in Table 1 below.[2] This represents a 5 percent net reduction in system costs, which are borne by customers, and is allocated as follows:

- DEC service territory: All three resource portfolios (gas, nuclear and regional nuclear) cost ***at least $4.7 billion less*** under the High EE/DSM case sensitivity than under the Base EE/DSM case.

- PEC service territory: The portfolio with High EE/DSM case resources costs ***at least $4.3 billion less*** than the preferred resource plan with Base EE/DSM case resources.

[2] For a detailed cost comparison of DEC's Base, High EE/DSM, and Renewable capital expansion plans, and PEC's "High EE" and "Base EE" portfolios, *see* Attachment 1.

Table 1: Customer Cost Savings from Increased Energy Efficiency

Revenue Requirement Forecast ($ billions present value)	**Duke Energy Carolinas**	**Progress Energy Carolinas**	**Duke Energy System**
High EE/DSM Case	$ 112.6	$ 83.2	$ 195.8
Base EE/DSM Case	$ 117.3	$ 87.5	$ 204.8
Potential Savings	**$ 4.7**	**$ 4.3**	**$ 9 billion**

In light of the $9 billion savings opportunity reflected in the High EE/DSM cases, to lower costs for their customers, DEC and PEC should select a preferred plan that includes significantly higher levels of energy efficiency than in their EE/DSM base cases, such as their High EE/DSM cases.

1. DEC's portfolio analysis demonstrates that increased levels of energy efficiency lower total system costs.

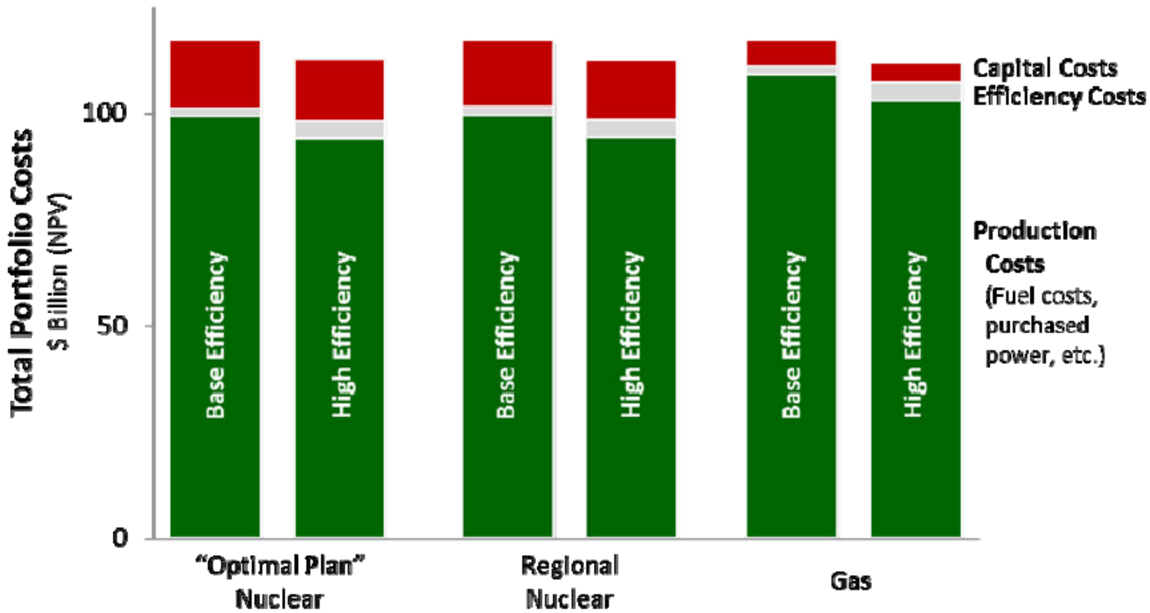
DEC modeled three resource portfolios—gas, nuclear, and regional nuclear–in both base case and sensitivity analyses. DEC 2012 IRP at 105. For the base case, each portfolio included EE/DSM resources based on DEC's internal expectations for demand-side resources and its 2011 Market Potential Study. *Id.* at 103. DEC also evaluated a High EE/DSM case sensitivity, which reflects higher levels of savings from DEC's EE/DSM programs as compared to the base case. *Id.* at 39-40.[3]

DEC's analysis shows that the three resource portfolios it modeled all cost significantly less—***at least $4.7 billion less***—under the High EE/DSM case sensitivity than under the Base EE/DSM Case. Figure 1 depicts the net present value of the total system costs of each portfolio under a capital expansion plan that includes the Base EE/DSM Case and a plan that includes the High EE/DSM Case. Costs are categorized as capital (i.e. power plant construction), efficiency (i.e. cost of implementing the EE/DSM

[3] The adequacy of DEC's Base and High EE/DSM case forecasts is discussed in Section IV.

case), and production (i.e. fuel costs). For each portfolio, the total system cost of the High EE/DSM is significantly less than that of the base EE/DSM case. This $4.7 billion cost difference represents about 4% of total costs over the 50-year time frame of the analysis.

Figure 1: Total System Cost of DEC's Resource Portfolios, Base Efficiency v. High Efficiency.[4]



Comparing the High and Base levels of efficiency across all three DEC portfolios, it appears that most of the gross savings are due to reduced fuel use, which is included in production costs, but about 20 percent of the system cost savings are due to avoiding about 1,400 MW of new generation (as represented by reduced capital costs). These savings, which are presented in greater detail in Attachment 1, stand in stark contrast to the zero cost difference between the gas, nuclear and regional nuclear portfolios under base case assumptions. DEC's modeling data also shows that the additional energy efficiency reduces forecast CO_2 emissions by almost [redacted] in each portfolio.

[4] Figure 1 was derived from DEC's quantitative analysis in its IRP, which DEC describes in Appendix A. *See* DEC 2012 IRP at 101-112.

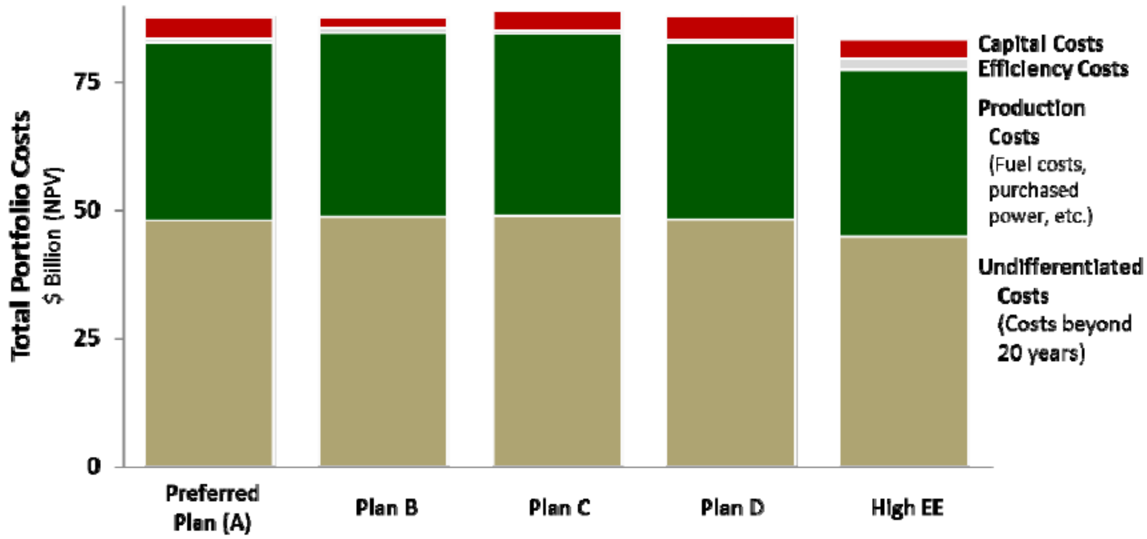
2. PEC's portfolio analysis also demonstrates that increased levels of energy efficiency lower total system costs.

PEC developed four alternative resource portfolios, Plans A through D, in its sensitivity analysis, plus an "Aspirational Plan," which consists of PEC's Plan A modified to include the High EE case. PEC modeled the High EE case under the same assumptions it used to model Plans A-D in the "Current Trends" scenario. PEC 2012 IRP at A-4-5. PEC did not choose to pass the High EE sensitivity to the second, scenario analysis phase of resource planning. *Id.* at A-5. For the base EE case, each alternative resource portfolio included EE/DSM resources based on PEC's 2012 potential assessment. *Id.* at E-12. For the High EE case sensitivity, PEC forecast a higher level of savings from PEC's EE/DSM programs, "serv[ing] as an aspirational target for future EE plans and programs." *Id.* at A-5.[5]

PEC's analysis shows that its High EE case sensitivity ***costs at least $4.3 billion less*** than the Base EE Case. Figure 2 depicts the PVRR of the total system costs of each portfolio as well as the High EE case sensitivity. Costs are categorized as capital (i.e. power plant construction), efficiency (i.e. cost of implementing the EE/DSM case), and production (i.e. fuel costs). Because PEC's model does not differentiate among cost categories beyond 2031, Figure 2 shows costs the model refers to as [redacted] as "undifferentiated" costs. The $4.3 billion cost difference represents about 5% of total costs over the time frame of the analysis.

[5] The adequacy of the PEC's Base and High EE case forecasts is discussed in Section IV.

Figure 2: Total System Cost of PEC's Resource Portfolios[6]



Comparing the High and Base levels of efficiency, it appears that most of the gross savings under the High EE case are due to reduced fuel use, which is included in production cost, but about ten percent of the system cost savings are due to avoiding about 798 MW of new generation (as represented by reduced capital costs).

The $4.3 billion in savings under the High EE plan, presented in greater detail in Attachment 1, stands in stark contrast to the $0.1 – $1.2 billion cost difference between the four plans modeled under base case assumptions. Moreover, PEC's modeling data shows that the additional energy efficiency reduces forecasted CO_2 emissions by over [redacted][7]

In sum, DEC's and PEC's quantitative analyses illustrate that a "least cost mix" of resource options includes increased levels of energy efficiency as compared to the companies' base cases. The High EE/DSM cases represent nearly $9 billion in cost savings, or roughly 5 percent of the total cost of the DEC and PEC system, including

[6] Figure 1 was derived from PEC's quantitative analysis in its IRP, which PEC described in Appendix A. *See* PEC 2012 IRP at A-1 - A-19.
[7] The CO_2 data was provided in a PEC response to an informal data request.

reduced capital costs due to avoided new generation. In light of these significant cost savings to customers, DEC and PEC should increase the role of energy efficiency in their overall resource mixes.

B. Increased use of EE/DSM would expose customers to a lower risk of cost increases.

In addition to lowering total system cost, energy efficiency also lowers the risk profile of a resource mix. For both DEC and PEC, the qualitative analysis of risk in the IRP shows that all portfolios with High EE/DSM resources expose customers to less risk than the "preferred plan" or other supply-side alternatives. Thus, to lower the risk of higher-than-forecast costs to their customers, each utility should select a preferred plan that includes significantly higher levels of energy efficiency.

DEC compared its three alternative resource portfolios across a range of sensitivities "to assess the impact of various risk factors on the costs to serve customers." DEC 2012 IRP at 104. Similarly, PEC compared the four resource portfolios it modeled across four scenarios "to determine which plan is the most robust; that is, which plan performs the best, given the risks and uncertainties the future holds." PEC 2012 IRP at A-5. Although there is no standard metric to measure the risk to customers of price increases, it is possible to compare the risk associated with different levels of investment in different resources. However, the DEC and PEC IRPs did not include a comprehensive comparison of the risk of supply- and demand-side resources.

As discussed below, DEC and PEC evaluated the risks of supply-side resources with respect to fuel, environmental and capital costs, scheduling inflexibility and implementation failure, and concluded that their preferred plans carry less risk than alternative portfolios. DEC 2012 IRP at 109; PEC 2012 IRP at A-8. However, the companies did not conduct a similar analysis of demand-side resources. This stems from the fact that DEC and PEC opted to analyze EE/DSM resources as sensitivities, not as resource alternatives. Thus, the IRPs present only a cursory discussion of risks associated with increased levels of efficiency, such as uncertainties about customer participation and regulatory approval, and do not compare these risks to the risks associated with the supply-side resources included in the preferred portfolios, such as nuclear power.

Despite this shortcoming in both plans, data from DEC and PEC's IRP analyses allows for a degree of quantitative and qualitative comparison, which shows that the risks presented by demand-side resources are, in fact, smaller than those for supply-side resources, as discussed below.

1. Fuel and environmental cost risks.

DEC and PEC customers bear a substantial risk of price increases if fuel prices and environmental costs, such as a price on CO_2 emissions, are higher than anticipated because these costs are passed through to customers. As discussed below, neither PEC nor DEC considered increased levels of EE/DSM resources as a way to mitigate fuel price risks. However, increased EE/DSM resources are more effective at reducing fuel price risk than is any conventional supply-side resource and should have been considered in the companies' IRPs.

DEC and PEC explicitly consider potential costs associated with CO_2 emissions when comparing supply-side resource alternatives. For example, DEC notes that "[o]ne of the major benefits of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit." DEC IRP at 110. Among the environmental attributes PEC uses to rank its alternative supply-side resource plans, PEC gives the strongest weight to CO_2 emissions. PEC IRP at A-7.

Nevertheless, the companies fail to adequately assess a broad range of environmental risks in the quantitative portions of their IRPs. DEC only considers environmental risks from a compliance perspective in its screening analysis. DEC IRP at 102. PEC goes only somewhat further, explicitly considering air emissions in its portfolio analysis. PEC 2012 IRP at A-7. In contrast, the Tennessee Valley Authority ("TVA") evaluated the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts (heat transferred to the environment), and waste disposal costs (coal ash and nuclear) in its 2011 IRP. TVA 2011 IRP at A172-A181. Adopting a broader approach, similar to that used by TVA, would allow DEC and PEC to be more explicit about how they balance various environmental risks.

Additionally, ignoring key categories of risk can introduce bias into the analysis. For example, PEC's decision to constrain its analysis to air emissions represents a subtle bias towards nuclear power over natural gas. This is relevant because PEC contrasts nuclear (Plan A) with non-nuclear (Plan B). PEC 2012 IRP at A-4. In its analysis of environmental attributes used to rank alternative supply-side resource plans, PEC does not consider the risks associated with nuclear waste storage and disposal, PEC IRP at A-7 and Appendix F. Notably, DEC acknowledges that nuclear waste storage and disposal is a major emerging issue in the Nuclear Regulatory Commission and the federal courts. DEC 2012 IRP at 92. The significant and uncertain costs associated with the handling and storage of nuclear waste should be both discussed and quantitatively assessed in the utilities' resource evaluations.

a. DEC's fuel cost risk analysis.

DEC's fuel price risk analysis appears to have played a major role in its selection of a preferred plan. Although DEC cites the reduced fuel cost risk in support of including nuclear generation in its plan, DEC ignores the fact that EE/DSM resources have an even lower fuel price risk than do supply-side resources.[8]

In the past, DEC modeling data has shown how higher EE/DSM resources reduce system risk due to fuel price variability more effectively than portfolios that include higher nuclear or gas resource alternatives. SACE's analysis of DEC's 2010 and 2011 IRPs showed that under conditions of high fuel and high CO_2 prices, selecting the High EE/DSM strategy mitigates price spikes by $1-2 billion.[9] This held true regardless of the type or level of supply-side investment under consideration. For its 2012 IRP, however, DEC did not conduct similar analyses of its High EE/DSM case under conditions of high fuel or high CO_2 prices.[10]

Not only has DEC dropped its evaluation of EE/DSM resources when studying fuel and environmental cost risk, but DEC's 2012 IRP analysis constrains the use of EE/DSM programs as a tool to mitigate costs in regulatory risk sensitivities. In its 2010 and 2011 IRPs, all of the portfolios DEC considered as alternatives to meet legislative or regulatory environmental requirements included the High EE/DSM case. For the 2012 IRP, however, DEC appears to have used Base Case EE/DSM resources in its Clean

[8] To the extent that DSM resources bear a "fuel cost" risk, it is likely inversely correlated with electric rates. As electric rates rise, DSM participation incentives could increase and thus result in higher participation rates. An exception would be standby generation DSM programs.

[9] This price spike mitigation is in addition to the cost advantage demonstrated for High EE/DSM resources in the base case. *See* Comments on DEC's 2011 IRP at 4, Docket No. E-100, Sub 128 (Jan. 13, 2012).

[10] DEC has asserted in prior proceedings that it does not run High DSM sensitivities under varying cost conditions, such as high fuel and CO_2 prices. However, this assertion runs counter to DEC's own modeling data, which it provided in data responses.

Energy Standard ("CES") sensitivities even though energy efficiency is included in DEC's definition of "Clean Energy." DEC 2012 IRP at 107. As an emissions-free clean energy resource, increased levels of energy efficiency can reduce environmental compliance costs. DEC should not pass over EE in its plans to meet more stringent environmental regulations.

b. PEC's fuel cost risk analysis.

PEC appears to view natural gas prices as its main fuel cost risk. Natural gas prices represent the single largest risk of total system cost impacts in PEC's sensitivity analysis.[11] "High Gas Prices" were considered as a component in two of the four scenarios PEC used. PEC 2012 IRP at A-6. PEC gave a 30% weight to System Fuel Price Volatility in its ranking of alternative plans, which considered variation in gas prices but not coal, uranium, or other fuel prices. *Id.* at A-6 - 7.

However, PEC ignores the value of EE/DSM resources in reducing fuel and environmental cost risk. As illustrated in Figure 2 and Attachment 1, a plan with High EE resources results in lower fuel and other production costs than the four alternative plans PEC modeled in its scenario analysis.[12]

Moreover, if PEC had evaluated its High EE case for System Fuel Price Volatility, it would have scored substantially higher than any of the four alternative plans emphasized by PEC. As illustrated in Table 2 below, not only does the High EE plan have $4.3 billion in lower costs, but the plan results in a reduced rate of price growth and lower system fuel price volatility.

[11] PEC Response to Informal Data Request.

[12] To the extent that DSM resources bear a "fuel cost" risk, it is likely inversely correlated with electric rates. As electric rates rise, DSM participation incentives could increase and thus result in higher participation rates. An exception would be standby generation DSM programs.

Table 2: Customer Cost Attributes of Alternative Resource Plans[13]

	Preferred Plan (A)	Plan B	Plan C	Plan D	High EE Plan
Revenue Requirement ($ Billions)	$ 87.5	$ 87.6	$ 88.7	$ 87.8	$ 83.2
Price Growth	3.8 %	3.7 %	3.9 %	3.7 %	3.4 %
System Fuel Price Volatility	8.7	9.8	9.6	8.4	7.8

In addition to failing to provide a fuel cost risk analysis for the High EE case, PEC failed to evaluate EE/DSM resources in its quantitative analysis of environmental (air emissions) impacts. PEC 2012 IRP, Appendix A. As noted above, PEC, like DEC, should not ignore increased levels of energy efficiency as a way to reduce environmental compliance costs and impacts in light of increasingly stringent regulations.

2. Capital cost risk.

Another source of risk is the potential for capital cost increases. EE/DSM programs (like nuclear power projects) have relatively low annual expenses, *i.e.* fuel and operating costs, as compared to fossil fuel generation. Most of the cost associated with efficiency is program cost; as a one-time resource investment, program cost is more similar to capital cost than fuel or operating costs.

Both DEC and PEC performed a sensitivity analysis to assess the risk of increasing capital costs. However, as with fuel and environmental cost analysis, neither utility performed these sensitivity analyses on High EE/DSM case resources, instead focusing on nuclear and gas resources. Applying the methods used by DEC and PEC for supply-side resource cost risk, it appears that EE/DSM programs present far lower capital cost risks than do supply-side resources.

[13] The data in this table is from the PEC 2012 IRP at A-18, except as follows: The Revenue Requirement has been adjusted to include cost of energy efficiency programs (*see* Attachment 1). SACE performed the calculations for the High EE plan utilizing PEC workpapers by adjusting for High EE case fuel use and efficiency program costs.

Both utilities' model data suggests that EE/DSM programs do not represent a substantial capital cost risk, particularly as compared to nuclear. DEC's analysis indicates that nuclear is about four times more sensitive to capital cost increases than is gas. For example, a 10% increase in nuclear capital costs increases portfolio costs by about $1.2 billion, while the same increase in gas capital costs increases portfolio costs only by about $0.3 billion. DEC 2012 IRP at 108. Although DEC did not perform a capital cost sensitivity for EE/DSM resources, DEC's model data indicates that a 10% increase in EE/DSM costs would increase portfolio costs by only about $0.2 - 0.4 billion.[14]

PEC considered the risk of increasing capital (or construction) costs in both its sensitivity and scenario analyses. PEC evaluated both nuclear and energy efficiency [redacted] PEC's analysis indicates that nuclear is about [redacted] sensitive to capital cost increases than are EE/DSM resources, even though the High EE resource case provides nearly [redacted] the capacity as nuclear.

Table 3: Impact of High Capital Costs, Nuclear vs. EE/DSM

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

To the extent that EE/DSM capital costs do escalate, the risks are mitigated by the nature of EE/DSM program impacts. The cost of demand-side resources are phased in on

[14] This calculation of the impact of DSM/EE cost increases on portfolio costs is derived from the data contained in Attachment 1.

[15] PEC response to informal data request.

[redacted]

an annual basis, rather than in large increments as with a new power plant. DEC suggests that the regional nuclear portfolio has a financial advantage over other supply side resources because "[t]he substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases." DEC 2012 IRP at 109. The impact of EE/DSM costs on customer bills are spread out even more broadly over time. EE/DSM therefore represents a lower risk alternative to supply-side resources.

3. <u>Risk of scheduling inflexibility.</u>

Large power plant projects are relatively inflexible in terms of development schedule, making it difficult to adjust in response to changing conditions and increasing the risk of delay. As DEC notes with respect to its regional nuclear portfolio, "[s]maller blocks of base load generation brought on-line over a period of years would more closely match projected load growth," and the regional nuclear approach "would allow utilities to better optimize their portfolios as legislation or regulation change over time." DEC 2012 IRP at 109. PEC has even less control over managing this risk with respect to its nuclear plans because it intends to depend on other utilities (including DEC) with respect to the schedule for development of nuclear facilities.

Unlike large power plant projects, EE/DSM programs are flexible and can be managed to more closely match load growth because these resources are deployed in annual increments. PEC discusses constraints on the pace of bringing new EE/DSM programs online, citing regulatory approval, market channel development, and program flexibility as challenges to expanding program scale.

PEC 2012 IRP at E-13. Yet analogous constraints on supply-side development, including multiple regulatory approvals, site acquisition and development, and transmission constraints, are far more significant. Compared to supply-side resources, energy efficiency programs are relatively straightforward and inexpensive to expand, cancel or modify in response to changes in projected (or even experienced) load growth. DEC's and PEC's analyses fail to recognize that EE/DSM resources offer flexibility that can mitigate the costs of excess capacity associated with a reduction in load growth.

4. <u>Risk of implementation failure.</u>

Both power plants and EE/DSM programs bear a risk of market or regulatory barriers to resource development. On the supply side, for example, The Brattle Group recently reported that the high level of demand for work by boilermakers could impact coal plant compliance with the Mercury and Air Toxics Standards.[18] On the demand side, lower-than-forecasted customer participation is a potential risk.

Both DEC and PEC have made significant commitments to implement energy efficiency programs, as discussed in Section IV. In its IRP, DEC states that it is "committed to maximizing the implementation of cost-effective energy efficiency and demand response measures in its territory." DEC 2012 IRP at 38. Similarly, PEC states that it "will continue to seek Commission approval to implement DSM and EE programs that are cost effective and consistent with PEC's forecasted resource needs over the planning horizon." PEC 2012 IRP at 19.

Nevertheless, both IRPs cite customer participation as an obstacle to achieving the High EE/DSM levels of energy efficiency. For example, in explaining its exclusion of the High EE case from scenario analysis, PEC states that "the high EE targets are viewed as extremely aggressive and required customer participation is uncertain." PEC IRP at

[18] Martin Celebi, "Environmental Retrofits: Costs and Supply Chain Constraints," The Brattle Group, Presented at MISO Annual Stakeholders' Meeting (June 2012).

A-5. Both DEC and PEC cite the opportunity for non-residential customers to "opt out" of program participation as a constraint on achieving higher energy efficiency impacts. DEC 2012 IRP at 38; PEC 2012 IRP at E-10.

It is true that industrial customers' ability to opt out of utility EE/DSM programs, combined with a lack of external accountability for self-directed industrial programs, represents a significant constraint to achievement of all cost-effective energy efficiency on the utilities' systems. However, established programs across the nation, coupled with both utilities' performance to date, show how DEC and PEC can mitigate this implementation risk by improving non-residential EE/DSM program offerings and working with industrial customers, as discussed in Section V.B. Indeed, the Commission recently found that DEC "should continue its efforts to offer a robust portfolio of cost-effective DSM and EE programs attractive to its industrial and commercial customers, including those that have previously opted out of participation in the programs" and should "work with SACE and other intervenors to develop strategies to attract [these customers] to the Company's portfolio of programs."[19]

Both DEC and PEC's preferred plans consists of full or partial ownership of nuclear units, despite several obstacles to the timely, safe and cost-effective development of nuclear power units, as discussed in Section VIII, below. As in prior IRPs, the utilities do not explain why the risk of failed program implementation associated with the High

[19] Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, NCUC Docket No. E-7, Sub 1001 (Sept. 7, 2012), at 8. Additionally, the South Carolina Public Service Commission recently observed that DEC "should continue to explore cost-effective ways to encourage non-residential customers who have opted out to participate in the Company's energy efficiency programs." Order Approving Rider 4 and Additional Rates Covering Energy Efficiency and Demand Side Management Programs, SC PSC Docket No. 2011-303-E, (Oct. 30, 2012) at 3.

EE/DSM Case is greater than the risks associated with the development of supply-side resources, such as nuclear power plants.

In sum, both DEC and PEC should evaluate the risks associated with EE/DSM programs using an approach that is equivalent to the approach they use for supply-side resources. DEC and PEC should then explicitly analyze whether a higher level of EE/DSM programs, which each company's quantitative analysis shows lowers total system costs and risk, should be adopted in future recommended plans.

IV. DEC AND PEC FAILED TO PROPERLY CONSIDER ENERGY EFFICIENCY IN THEIR EVALUATION OF RESOURCE OPTIONS.

As discussed in the previous section, data underlying DEC's and PEC's resource plans demonstrate that including higher levels of EE would save customers money and reduce system-wide costs and risk. However, DEC and PEC do not evaluate efficiency as a resource equivalent to supply-side resources. As a result, they significantly underestimate and underutilize EE in their IRPs, and present plans that favor more expensive, riskier supply-side resources and do not result in the "least-cost mix" of resource options.

Leading utilities in many states expect to achieve more energy efficiency savings in the next five years than DEC or PEC expects to achieve in the next 10 or even 15 years. Energy efficiency is an abundant, least-cost resource. Energy efficiency reduces customer utility bills and can moderate rate increases in the long term by reducing or delaying the need for new generating capacity.[20] In fact, several states with leading energy efficiency programs have electricity rates comparable to, or even lower than, rates

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

in North Carolina.[21] Energy efficiency also reduces environmental impacts and compliance costs, conserves water, reduces energy market prices, lowers portfolio risk, promotes local economic development and job growth, and assists low-income populations.[22]

Indeed, the companies' own EE program performance and energy savings goals demonstrate the value of this resource. DEC and PEC have achieved significant savings in their first few years of program implementation at a low cost, and DEC has earned recognition as a regional leader in energy efficiency.

A. Both DEC's and PEC's energy efficiency programs are performing well at low cost, demonstrating that energy efficiency is a least-cost system resource that delivers significant energy savings.

DEC and PEC have increased their efficiency impacts in 2011, the most recent year for which data are available. As shown in Figure 3 below, each utility saved at least 0.3% of annual electricity sales with EE.

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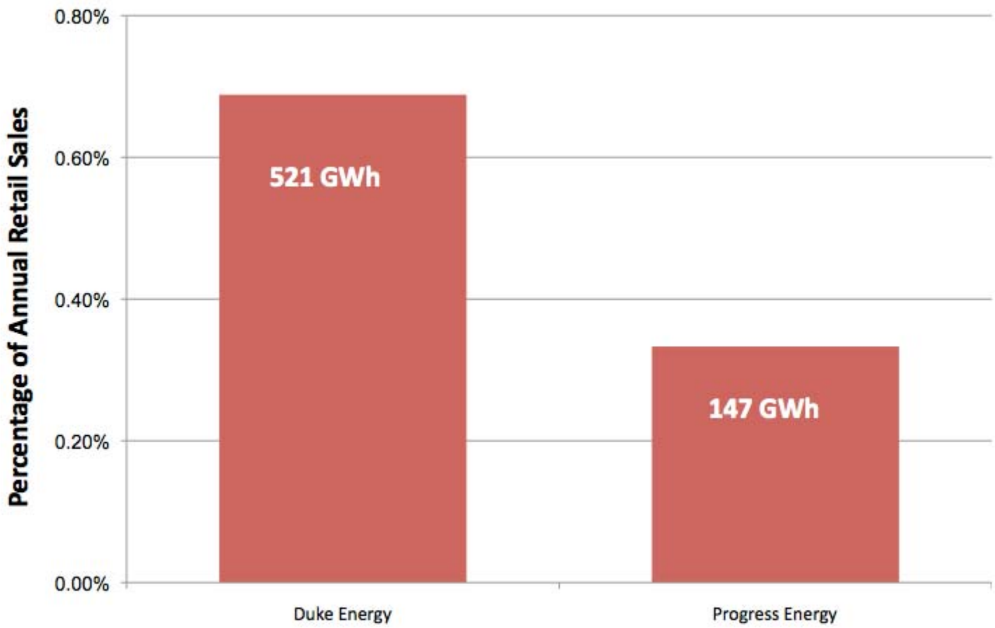
[21] John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.
[22] *Supra* note 1. *See also Analyzing and Managing Bill Impacts of Energy Efficiency Programs: Principles and Recommendations,* Utility Motivation and Energy Efficiency Working Group, State and Local Energy Efficiency Action Network (July 2011) at 6, note 4.

Figure 3: DEC and PEC 2011 Energy Efficiency Savings



Source: DEC's and PEC's 2012 EE/DSM applications. *See* NCUC Docket Nos. E-7 Sub 1001 and E-2, Sub 1019, respectively.

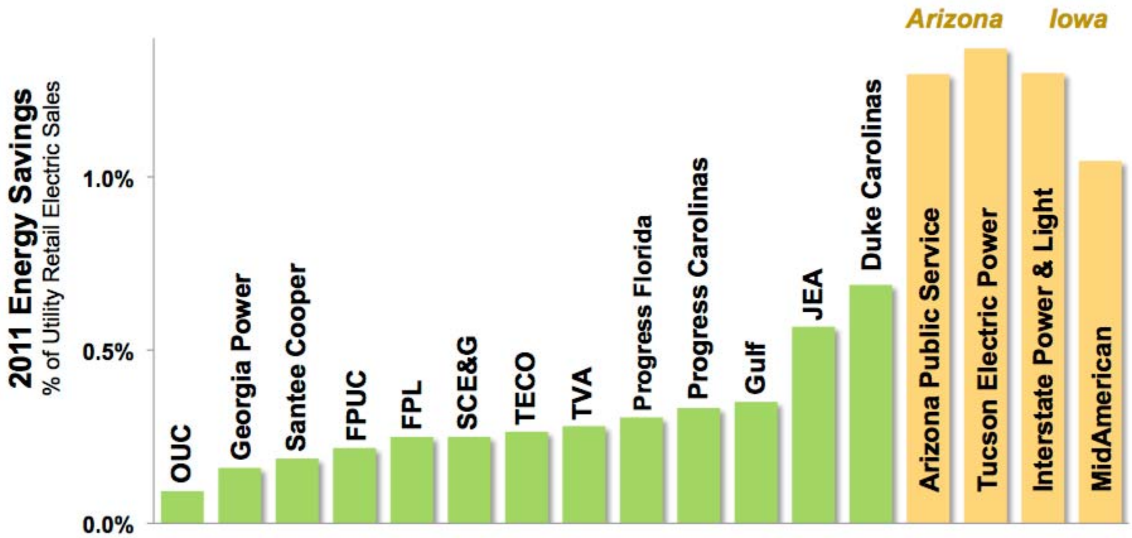
DEC is delivering high-performing, cost-effective energy efficiency programs to its customers. In both 2010 and 2011, DEC saved about 0.7 percent of its retail sales, achieving approximately 500 GWh of energy savings at a cost of about $57 million in 2010, and 520 GWh in 2011 DEC for a cost of about $59 million. In these first two full years of EE program implementation, DEC has achieved energy savings that are more than double the targeted amounts in the modified Save-A-Watt plan.[23]

DEC's energy efficiency program performance is among the best in the Southeast region. In 2011, DEC led the Southeast in energy savings from efficiency, saving 0.7% of annual sales, equal to more than 520 GWh of efficiency savings in 2011. As shown in

[23] The modified Save-a-Watt energy savings targets are set forth in the Agreement and Joint Stipulation of Settlement entered into by DEC, Environmental Defense Fund, the Natural Resources Defense Council, SACE, the Southern Environmental Law Center and the Public Staff in Docket No. E-7, 831, which was approved by the Commission with modifications on February 2, 2019.

Figure 4, DEC achieved far greater cost-effective energy savings than other major utilities in the Southeast.

Figure 4: Efficiency Impact as a Percentage of Retail Sales, 2011



Like DEC, PEC is delivering high-performing, cost-effective energy efficiency programs to its customers. As Table 4 shows, in 2010 and 2011, PEC saved roughly 0.3% and 0.4% percent of its retail sales, respectively. PEC saved approximately 127 GWh at a cost of about $46.4 million in 2010, and 168 GWh at a cost of about $52.0 million in 2011. PEC's 2011 savings were slightly less than it forecasted (8% lower) but the overall cost-effectiveness of the company's EE portfolio improved because its operations and maintenance ("O&M") expenditures were 5% less than forecasted – PEC projected O&M costs of $55 million,[24] and actual O&M costs were about $52 million.[25]

[24] PEC's 2011 EE/DSM Application, Exhibit 1 at 9 and 15, SC PSC Docket No. 2011-181-E.
[25] PEC's 2012 EE/DSM Application, Exhibit 1 at 14 and 32, SC PSC Docket No. 2012-93-E.

Table 4: 2010-12 PEC EE/DSM Annual Program Savings and Costs[26]

	Forecast Energy Savings (MWh)	Actual Energy Savings[27] (MWh)	Savings as a Percentage of Sales	Costs (Million $)[28]
2010	106,584	127,152	0.28%	$46.4
2011	183,763	168,369	0.38%	$52.0
2012	143,666	NA	0.32%	$65.4

For 2012, PEC projected that it would save about 144 GWh, or about 0.3% of sales, at a cost of about $65 million. This forecast suggests that the "first cost" of its portfolio, *i.e.*, the first year costs of the programs per kWh of energy saved, will increase.[29] This cost increase appears to be due to structural changes in PEC's portfolio, not an actual decrease in program cost-effectiveness. The main factors driving this trend appear to be:

- PEC forecasts that the impact of its residential lighting program, which is its low-cost workhorse, will decrease by about 8 GWh for 2012.
- PEC is adding small business and residential new construction programs, which are forecast to achieve 13 GWh in savings in 2012. These programs compensate for reduced savings from the residential lighting program, but at a significantly higher first cost. Because these types of programs tend to have a measure life that is 2-4 times greater than that of residential lighting programs, however, the impact on overall cost-effectiveness (e.g., levelized cost of energy) is likely to be small.

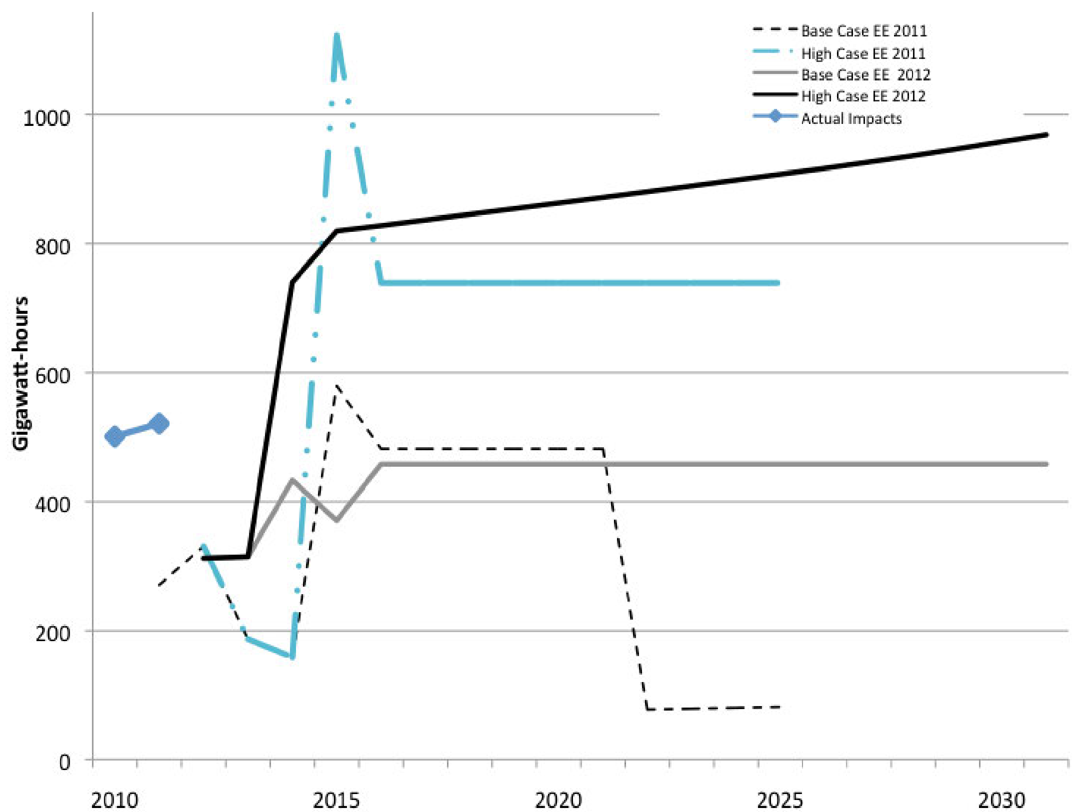
[26] The data in this table is derived from PEC's Exhibit 1 filing in its 2010-2012 cost recovery dockets. *See* SC PSC Docket Nos. 2010-161-E, 2011-181-E, and 2012-93-E. PEC's test period spans April 1- March 31. For the purposes of Table 1, the year represents the test period that ends in that calendar year, *i.e.* "2012" represents the test year spanning April 1, 2011 – March 31, 2012, the previous test period ending in 2011 is referred to as "2011," etc.
[27] Energy savings includes both EE and DR MWh savings.
[28] Cost represents O&M expenses plus SACE's calculation of portion of administrative costs.
[29] For the purposes of these comments, "first cost" is calculated by dividing the first year of costs of the programs, which included O&M costs and an allocable share of administrative costs, by the first year of energy savings.

Even accounting for this projected cost increase, PEC's EE programs continue to operate at relatively low cost by industry standards. Assuming a typical measure life of 10 years, PEC's EE programs have a levelized cost in the range of 2-4 cents per kWh, which is highly competitive with supply-side resources.

B. Both DEC and PEC Have Improved Their Energy Efficiency Forecasts in the 2012 IRPs.

In prior years, DEC's efficiency forecast included dramatic swings up and down from year to year. DEC appears to have addressed this problem, as Figure 5 illustrates.

Figure 5: Energy Savings as Estimated in Duke's 2011 and 2012 IRPs



Source: First Data Request to Duke Energy Carolinas, Response to Q1.d; DEC's Application of Duke Energy Carolinas, LLC for Approval of Rider 4, SC PSC Docket No. 2012-303-E, Vintage 1, Exhibit 2 and Vintage 2, Exhibit 2.

In addition to eliminating the forecast swings, DEC has revised its methods to include substantial program impacts beyond 2022. This new method results in an increase in the Base EE/DSM Case long-term energy savings forecast as compared to the past two IRPs, as summarized in Table 5.

Table 5: DEC Base EE/DSM Case Shows Increased Long-Term Savings

IRP Filing	**2025 Base Case EE/DSM Impacts**
2010	5,000 GWh
2011	4,737 GWh
2012	6,011 GWh

DEC has also improved its High EE/DSM Case forecast. For the 2011 IRP, DEC modeled a High EE/DSM Case, forecasting impacts of slightly more than 1% of prior year retail electricity sales beginning in 2015. DEC 2011 IRP at 38. The High EE/DSM case sensitivity in DEC's 2012 IRP represents a significant increase from the prior DEC IRP, and approximately twice as much energy savings as its Base Case. The increase in DEC's High EE/DSM Case stems from DEC's commitment to increased energy savings targets in an agreement with SACE and other parties in connection with the merger of Duke Energy and Progress Energy (the "Merger Agreement").[30]

[30] In the S.C. Public Service Commission ("SC PSC") proceeding related to the merger of Duke Energy and Progress Energy, Docket No. 2011-158-E, the companies entered into a settlement agreement with SACE, Environmental Defense Fund, and the S.C. Coastal Conservation League (the "Merger Agreement"), in which, among other things, DEC and PEC agreed to annual energy savings target of 1% beginning in 2015, and a cumulative target of 7% of retail sales from 2014-2018. The Merger Agreement was approved by the SC PSC in its Order Approving Joint Dispatch Agreement, Order 2012-517 (July 11, 2012) at 43. For its 2012 IRP, DEC did not model the additional savings that would be represented by achieving a cumulative savings target of 7% of retail electricity sales over the five-year time period of 2014-2018, as stated in the Merger Agreement. Instead, PEC modeled savings of approximately 5% of retail electricity sales over the five-year period.

PEC has improved its efficiency forecasting methods by developing a High EE case and increasing its base case forecast. Unlike past IRPs in which PEC forecasted only one level of EE investment in its base case set of assumptions, the 2012 IRP includes a High EE case, which forecasts energy savings of slightly more than 1% of prior year retail electricity sales beginning in 2015. PEC's inclusion of a High EE case stems from the company's commitment to increased energy savings targets in the Merger Agreement.[31] Like DEC's increase in its High DSM/EE Case, PEC's modeling of a High EE case in developing its IRP represents an important step forward for the company in meeting the long-term needs of its customers through the lowest cost, lowest risk resource, energy efficiency. Moreover, PEC's base EE case includes greater levels of efficiency savings than the forecast in PEC's 2011 IRP. PEC 2012 IRP at E-12.

C. The long-term efficiency savings projections of DEC and PEC continue to lag behind those of leading utilities.

Despite successful program delivery and improved efficiency forecasting, neither company's actual savings or forecasted future program impacts reflect the level of savings that are being achieved by many leading energy efficiency portfolios. Moreover, problems persist with the companies' energy efficiency forecasting.

DEC and PEC project that they will achieve between 7-18% in cumulative energy savings from energy efficiency programs at the end of their IRP planning cycle, as shown in Table 6.

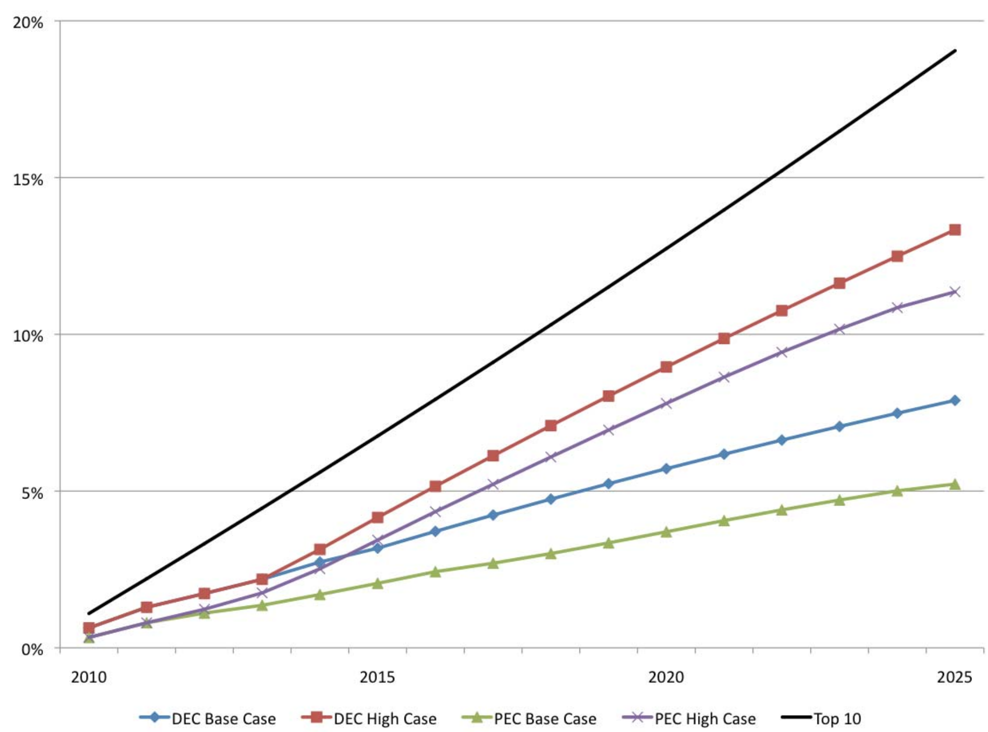
[31] Like DEC, in its 2012 IRP, PEC does not model the additional savings that would be represented by achieving a cumulative savings target of 7% of retail electricity sales over the five-year time period of 2014-2018. The savings represented during those five years represents approximately 5% of retail electricity sales.

Table 6: Energy Efficiency Projections by Utility

	Final Year	Cumulative Savings as % of 2012 Sales	
		Base Case	High EE/DSM Case
DEC	2031	10%	18%
PEC	2032	7%	16%

These forecasts, including the forecast for DEC and PEC's High EE/DSM case sensitivities, are significantly less than those of leading utilities, as shown in Figure 6, below.

Figure 6: Energy Efficiency Savings Impacts of DEC and PEC Compared to "Leading" Utility



Source: DEC 2012 IRP and PEC 2012 IRP; and Sciortino, M. *et al.*, *Energy Efficiency Resource Standards: A Progress Report on State Experience*, American Council for an Energy-Efficient Economy, Research Report U112 (June 2011).

DEC's and PEC's IRP savings forecasts project annual savings of far less than 1% of sales per year. Yet a 1% annual savings projection would be consistent with the savings achieved by each company over the past two years, as well as savings achieved by utilities across the country, and the findings of recent studies focused on the South. Notably, a 2010 Georgia Tech meta-analysis of several potential studies in the South found that the achievable electric efficiency potential ranges from 7.2 to 13.6% after 10 years.[32] Moreover, annual savings of at least 1% is consistent with commitments made by the utilities themselves in the Merger Agreement and DEC's long-term performance goals as provided in the modified Save-A-Watt settlement agreement.[33]

Therefore, while DEC and PEC's EE program performance is a good start, there is ample room for improvement, both in terms of the integration of EE in the IRP and EE program offerings, as discussed below.

D. DEC and PEC continue to undervalue efficiency in their long-term efficiency forecasts, despite the utilities' actual experience.

DEC and PEC's actual energy savings impacts have been significantly higher than the forecasted impacts that in their utilities' Base EE/DSM Cases. Figure 5 shows DEC's actual energy savings impacts in 2010-2011, represented by the two diamonds on the left of the graph. Although DEC indicates that it has "updated expectations on the performance of the EE programs," DEC does not directly discuss its forecast 40% drop in program impacts over the next several years. DEC 2012 IRP at 38.

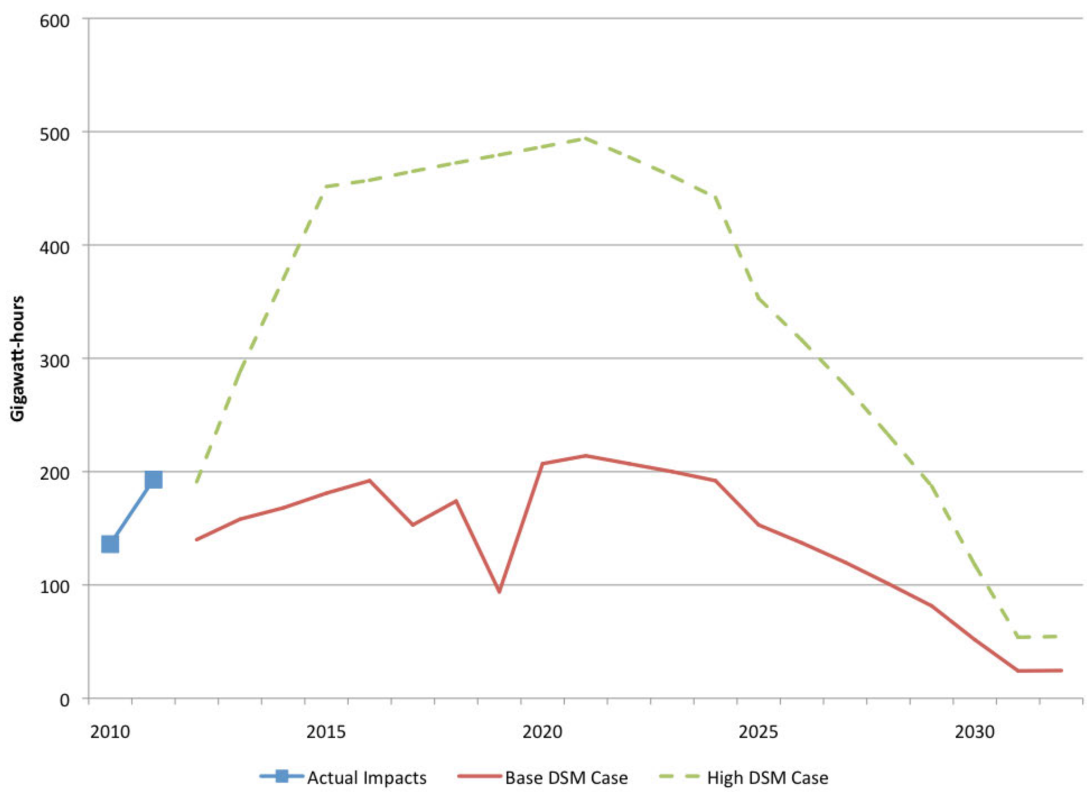
PEC's efficiency forecast, though improved, also raises some concerns. Specifically, the forecast shows a 50 GWh decrease between 2015 and 2017, and a

[32]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, at 15 (finding that the "medium case" energy savings potential for utility-led energy efficiency programs is approximately 17% by 2025).

[33] DEC agreed to an overall annual energy efficiency target of at least 1% of 2009 weather-normalized retail sales by 2015. *See* Agreement and Joint Stipulation of Settlement, Exhibit B at 21, NCUC Docket No. E-7, Sub 831 (approved subject to certain Commission-required modifications on Feb. 9, 20010).

continuing decline in efficiency from 2028-2032 in both the base and High EE cases, as Figure 7 illustrates.

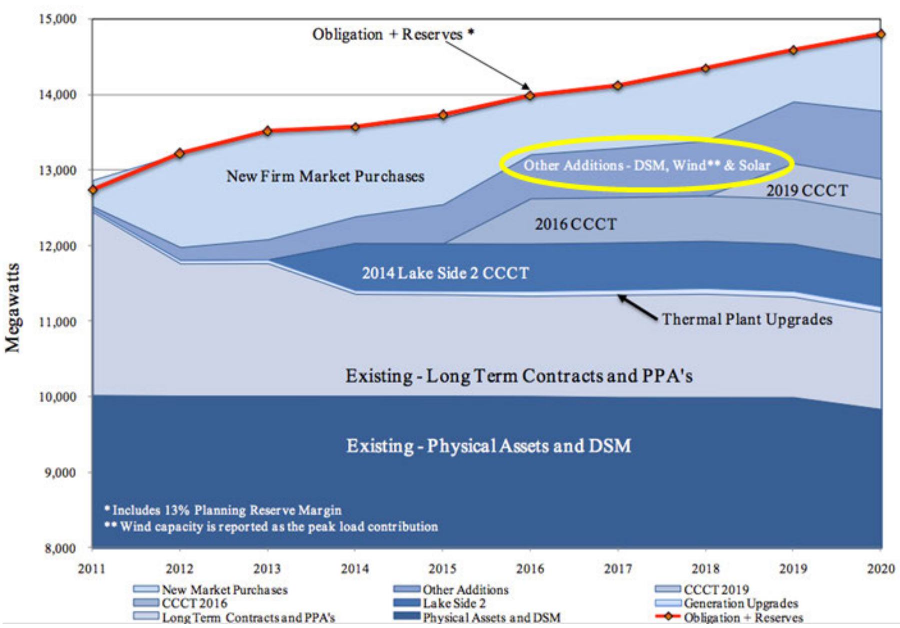
Figure 7: PEC's 2012 Base EE and High EE Cases



These projections suggest that the efficiency resource is not properly considered in the long term.

DEC and PEC should improve their efficiency modeling to allow the resource to grow in the long-term, consistent with the long-term efficiency forecasts of electric utilities that have successfully delivered efficiency savings for decades. The Northwest Power and Conservation Council, for example, concluded that at least 85% of the projected 20-year energy savings estimates in its first regional plan were realized, demonstrating that long-term planning and results can be achieved.[34] One of the utilities affected by those regional plans, PacifiCorp, anticipates continued, sustained growth of the contribution of DSM resources in its IRP, as illustrated in Figure 8.

Figure 8: PacifiCorp Preferred Resource Portfolio, 2011 IRP



PacifiCorp, 2011 Integrated Resource Plan, 2011. Volume I at 234.

Both DEC and PEC can and should plan for similar growth. Indeed, according to the *National Action Plan for Energy Efficiency*, "[m]ost utilities have an established approach to forecast long-term market prices, and the same forecasting technique and assumptions should be used for energy efficiency as are used to evaluate supply-side resource options."[35]

One major barrier to proper integration of EE into the DEC and PEC IRPs is each company's modeling of energy efficiency as a fixed model input, best characterized as an

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[34]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.

[35]National Action Plan for Energy Efficiency Leadership Group, *National Action Plan for Energy Efficiency* (July 2006), at 3-4.

adjustment to the load forecast, rather than as a resource that may be optimized during the modeling process. While this treatment is appropriate for demand response measures, the industry best practice is to treat energy efficiency investments as equal or even preferred to supply-side resources for planning purposes.[36]

DEC and PEC 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 uses two supply curves for energy efficiency in the model that develops least-cost portfolios.[37] The use of two supply curves allows for different treatment of discretionary and lost-opportunity energy efficiency resources.[38] 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 that DEC and PEC use does not allow this distinction to be made.

E. PEC and DEC have enhanced their efficiency portfolios, but many new program opportunities exist.

Both DEC and PEC continue to develop and propose new programs. Since filing its 2011 IRP, DEC has proposed, and the Commission has approved, several new EE programs: a new appliance recycling program, residential behavior change program (My Home Energy Comparison Report) and low-income program (Neighborhood Energy Saver). For its part, PEC has proposed and received Commission approval of a

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[36] *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 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.

[37] *Id.* at 71.

[38] 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.

residential pre-pay program, residential new construction program, and a small business program. SACE and the Sierra Club commend DEC and PEC for offering new and innovative EE programs to underserved customers, and urge both companies to pursue additional program opportunities, particularly those targeting energy-intensive customer sectors, as discussed below.

1. DEC and PEC must move beyond residential CFL programs.

In 2010 and 2011, DEC and PEC offered residential lighting incentives focusing on compact fluorescent light bulbs ("CFLs"). Each company's residential lighting program is its largest and lowest-cost EE program. Currently, DEC and PEC capture the bulk of their program impacts from residential CFL programs, as Table 7 shows.

Table 7: Residential Lighting Impacts as Percentage of EE Savings, 2011

	2011 Residential Lighting EE Impacts	2011 Total EE impacts	Residential Light EE Impacts as Percentage of Total Savings
DEC	367,536	478,995	77%
PEC	150,013	296,202	51%

Source: Duff Exhibit 1 at 3, NCUC Docket No. E-7, Sub 1001 (March 23, 2012).; PEC Exhibit 1 at 34, NCUC Docket No. E-2, Sub 1019 (June 14, 2012).

Over the next decade, federal lighting standards will increase the efficiency of many bulbs. This increasing standard will benefit consumers, but also raise the bar for utilities in terms of capturing lighting savings because they will get credit only for energy savings that go beyond existing standards. DEC and PEC both appear to have decreased their efficiency forecasts in part due to the phase-in of federal lighting and appliance efficiency standards.[39] Although increasing standards may result in a gradual decrease in participation rates in the lighting programs over the next four years, ample opportunity

[39] *See* DEC 2012 IRP at 115 and Progress Energy Carolinas: Electric Energy Efficiency Potential Assessment (June 5, 2012) at 15.

for energy savings in lighting programs remain. Indeed, leading utilities, such as Efficiency Vermont, are continuing to forecast lighting savings. The Carolinas utilities should do the same, and should look beyond CFL lighting offerings to continue to enhance their efficiency portfolios.

2. DEC and PEC should improve existing programs and pursue new energy efficiency program opportunities.

Although DEC and PEC have implemented several new programs in the past year, there are numerous efficiency opportunities that they are not capturing, and the utilities must plan to expand its efficiency portfolios. In fact, approximately [redacted] of DEC's incremental projected savings in its High EE/DSM Case, and [redacted] of its Base EE/DSM Case, are from unidentified programs and measures.[40] To achieve future savings, DEC and PEC should consider implementing programs such as those shown in Table 8 below.

Table 8: Energy Efficiency Programs that DEC and PEC Should Consider

Program Type	Example Program/Provider	Description
Multi-Family	NYSERDA Multifamily Performance Program	Challenges multifamily owners to reduce total source energy consumption by 15%
Residential On-Bill Financing	Clean Energy Works Oregon	Residential owner or rental occupied homes receive a Home Energy Assessment, and are provided with no money down financing for insulation, efficient windows, air and duct sealing, heating systems and water heating systems
Residential New Construction	SCE&G	Incentives for participation in the Energy Star New Homes program.
Commercial On-Bill Financing	Connecticut Small Business Energy Advantage	Loans available for $500-100,000 for small business customers to install efficient lighting, HVAC, refrigeration, VFDs, ECMs and other

[40] DEC Response to SACE Data Request 1d.

		measures
Upstream Incentives for HVAC	Energy Solutions for PG&G, SCE, NV Energy, SDG&E and SMUD	HVAC distributors receive tiered incentives to stock and upsell high efficiency HVAC equipment
Commercial Commissioning or Re-commissioning	Xcel Energy in Colorado and Minnesota	Xcel pays for up to 75% of re-commissioning study cost, and an implementation rebate of up to $0.08 per lifetime kWh saved.
Commercial New Construction	MidAmerican in Iowa	Incentives offered by Carolinas utilities are applicable to new construction in the non-residential market, however a program targeted at new construction for non-residential doesn't exist. MidAmerian offers incentives to offset the cost of higher initial costs associated with the design and installation of energy efficient building options.

In addition to new programs, both PEC and DEC could modify their existing programs based on new research. Recent studies indicate that appliance replacement offers greater savings opportunities than assumed in current program plans. For example, a recent report on residential clothes dryers indicates that appliance testing underestimates dryer energy consumption, resulting in inaccurate savings projections from appliance replacement programs.[41] Another recent report shows that residential dehumidifiers consume more energy annually than an ENERGY STAR refrigerator, and could be a important source of EE savings.[42] Plug loads, also known as "miscellaneous energy loads," are also an emerging area for energy efficiency programs. For example, the Northwest Energy Efficiency Alliance recently identified 13 plug load technologies

[41]Denenberger, Dave, Serena Mau, Chris Calwell, Eric Wanless and Brendan Trimboli. *What Lurks Beneath: Energy Savings Opportunities from Better Testing and Technologies in Residential Clothes Dryers*. ACEEE Summer Study on Buildings, 2012.
[42]Mattison, Lauren, Dave Korn. *Dehumidifers: A Major Consumer of Residential Electricity.* ACEEE Summer Study on Buildings, 2012.

as “high-confidence” opportunities for EE programs.[43] Currently, a number of utilities promote plug load efficiency by incentivizing consumers to purchase ENERGY STAR electronics. These are just a few examples of recent developments DEC and PEC should consider as they work to achieve higher levels of energy savings.

3. Large customer opt-out provisions represent a lost energy savings opportunity for DEC and PEC

Industrial and large commercial customers across DEC’s and PEC service territories may “opt out” of utility-sponsored energy efficiency programs and associated riders if they implement their own EE measures. The industrial and large commercial sectors represent a large resource opportunity—likely more than half of the cost-effective energy efficiency potential. Failure to utilize this resource opportunity increases system costs for all classes of customers. Accordingly, DEC and PEC should pursue opportunities to offer programs tailored to these energy-intensive customer sectors.

In North Carolina, roughly 40% of eligible DEC customers and just over half of of eligible PEC customers have opted out of utility EE programs, as shown in Table 9.

Table 9: North Carolina Opt-outs as a Percentage of C&I Sales

Utility	% of MWh opted out
Duke Energy Carolinas	40%[44]
Progress Energy Carolinas	51%[45]

These high opt-out rates represent a significant constraint on each company’s energy savings.

[43] Frank, Marti, Jane Peters, Stephanie Fleming, Gregg Hardy, Matt Krick; *Taming the Beast: 13 Savings Opportunities for the Next Generation Consumer Electronics Programs*. ACEEE Summer Study 2012.
[44] Direct Testimony of Jane L. McManeus, Exhibit 4, NCUC Docket No. E-7, Sub 1001 (March 23, 2012).
[45] Direct Testimony of Robert P. Evans, Exhibit 3, NCUC Docket No. E-2 Sub 1019 (June 14, 2012).

DEC cites uncertainty regarding customer opt-outs as a reason that the High EE/DSM Case is not adopted in its preferred portfolio. DEC 2012 IRP at 112. Similarly, PEC reports that its Base EE case "includes the significant effect of certain large commercial and industrial customers 'opting out' of the programs." PEC 2012 IRP at E-10. Both DEC's Base EE/DSM Case and PEC's Base EE Case reflect lower-than-achievable savings in the large commercial and industrial sectors.

DEC's discussion of the cost difference between its Base and High EE/DSM Cases illustrates the significance of this lost opportunity. DEC acknowledges that "[t]he 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."[46] A high opt-out rate means a failure to capture potential savings in the commercial and industrial sectors, which increases system costs for all classes of customers.

Several steps could be taken to address the impact of non-residential opt-outs:

- DEC and PEC could improve the quality of their commercial and industrial programs, as discussed previously.
- The Commission could initiate a process to verify that customers who opt out actually implement their own efficiency measures, as required.[47]
- Commercial and industrial customers or their customer associations could work to provide to the electric utilities firmer estimates of their energy efficiency plans and projected impacts on energy use and demand.
- Utilities, industrial customers and others could work together to develop more attractive programs that meet the needs of industrial customers.

[46]Duke 2012 IRP at 112.
[47] Opt-out provisions do not exempt eligible customers from implementing EE measures; large customers may opt out of utility programs only if they implement their own energy efficiency projects.

- Policy-makers, regulators and stakeholders could revisit the opt out policy to ensure that supply-side investments are not being made due to a failure to take advantage of low-cost, low-risk energy efficiency resources.[48]

4. DEC and PEC should consider regional collaboration.

Regional collaboration would allow electric utilities to share lessons learned with one another concerning targeted offerings. Targeted programs, which utilize marketing and service delivery strategies that overcome barriers to the adoption of energy efficiency programs for a particular customer segment, often achieve higher participation rates even while offering lower participation incentives. The major Carolinas investor-owned utilities all offer some of these types of programs, though the program offerings are inconsistent, as illustrated in Table 10.

Table 10: Targeted Efficiency Programs, by Utility

	DEC	PEC	SCE&G
Low-Income	Approved 2012	Yes	Not offered
Education in Schools	Yes	Not offered	Not offered
Appliance Recycling	Approved 2012	Yes	Not offered
Residential New Construction	Not offered	Approved 2012	Yes
Residential Pre-Pay	No	Yes	No
Beyond CFL Lighting Incentives	Yes	Not offered	Not offered
Small Business	Not offered	Approved 2012	Not offered
Commercial Behavioral Change	Yes	Not offered	Piloted
Commercial Custom	Yes	Bundled in CIG program	Not offered

[48] The Carolinas are among only five states that allow complete opt-out for large customers, and the opt-out threshold of 1,000 MWh annual customer demand is much lower than thresholds used in other opt-out or self direct programs. *See* Anna Chittum, "Follow the Leaders: Improving Large Customer Self-Direct Programs," American Council for an Energy-Efficient Economy, Report No. IE112 (October 2011) and Merrian Borgeson, "Review of Self-direct Demand Side Management (DSM) Programs," Lawrence Berkeley National Laboratory (November 2012).

In addition to sharing lessons learned, Carolinas utilities should also explore regional marketing and partnerships with key efficiency vendors to 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.[49] 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.[50]

V. DEC AND PEC SHOULD INTEGRATE HIGHER LEVELS OF RENEWABLE ENERGY INTO THEIR PLANS.

Both DEC and PEC have a solid track record in complying with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (“REPS”). This experience demonstrates that renewable energy (“RE”) resources are available and can be developed at a reasonable cost, with minimal impact on ratepayers. Yet both the DEC and PEC 2012 resource plans reflect an overly cautious approach to the use of RE to meet system needs over the next 15 years. Both utilities should give RE resources greater consideration, particularly over the long term, because of their distinct advantages compared to other supply-side resources. For example, RE resources can yield fuel cost savings, hedge against market and regulatory risk factors, promote local economic development, reduce greenhouse gas and conventional pollutant emissions, and save

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

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

water.[51] DEC and PEC may be able to procure energy and capacity at a lower cost by investing in conventional generating resources. However, even if RE costs are currently modestly higher than conventional resources, as technology costs continue to fall and renewables become more cost-competitive with conventional supply-side options, the potential value of RE resources beyond their basic energy and capacity contributions justifies deeper analysis of these resources than the utilities conducted for their 2012 IRPs.

A. Renewable energy resources offer distinct advantages for utility resource portfolios.

Recent renewable energy resource potential studies identify onshore and offshore wind, solar photovoltaic, biomass, hydro, and landfill gas as available in the Carolinas.[52] These resources share several key attributes that distinguish them from conventional supply-side technologies:

- *Lower production costs*. The production costs for most renewable resources, including wind, solar, hydro, and landfill gas, are minimal. Because utilities dispatch generating resources primarily based on production cost (with lower-cost resources being dispatched first), energy generated by renewable resources with minimal production costs tends to displace an equivalent amount of conventionally produced energy on the utility's system. For example, during system peak hours, wind and solar energy typically displaces expensive, inefficient natural gas peaker production and some wholesale power needs, while during off-peak hours intermediate coal unit production is displaced. Thus, for each year of operation, wind and other low-production-cost renewables can be expected to result in significant fuel cost and purchased power savings for the utility.

[51] *See, e.g.,*, McLaren, J., Southeast Regional Clean Energy Policy Analysis, Chapter 5. NREL Technical Report TP-6A20-49192 (revised April 2011). Available at: http://www nrel.gov/tech_deployment/state_local_activities/pdfs/49192.pdf

[52] *See* Black & Veatch, South Carolina Resource Study, at 1-4, January 2012 (http://www.scstatehouse.gov/committeeinfo/EnergyAdvisoryCouncil/ResourceStudyComments/SCEACResourceStudy_FINAL.pdf); La Capra Associates, North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives, at 34, June 2011 (http://www.lacapra.com/downloads/NC_EPC_REPS_Report2011.pdf).

- *Smaller environmental footprints*. Renewables generally have smaller environmental footprints than conventional resources. This encompasses conventional air pollutants (e.g. NOx, SO_2, mercury, and PM), greenhouse gas emissions, freshwater withdrawal and consumption, and production of hazardous solid wastes. Some of these environmental impacts already have direct economic costs, and additional costs may be assigned in the future.
- *Modular nature*. Many renewable installations are modular in nature and can be added in small capacity blocks in a way that matches load more closely than large capacity acquisitions such as baseload nuclear and fossil plants.

Given these attributes, renewable resources are an attractive option for managing many categories of utility risk. The fuel and purchased power savings resulting from integration of wind and solar photovoltaic resources into utility portfolios provide a hedge against future fuel cost increases and tightening wholesale power markets. Power plants running on biomass fuels serve to diversify the utility's fuel sources. Emissions reductions and water savings from greater deployment of renewables can facilitate compliance with current, pending, and future EPA regulations. Renewable energy certificates can also reduce an electric utility's economic exposure to potential federal RPS and clean energy standards. Low-carbon renewable technologies can help utilities prepare for possible federal carbon-pricing policies. Unexpected shifts in consumer demand for electricity can also be weathered by adding or removing blocks of renewable capacity from deployment plans as needed. No other category of electricity generating resource simultaneously offers all of these attributes. [53]

[53] Although the intermittency of some renewable resources is often cited as a challenge for power system operators, it not necessarily a bar to successful integration of these resources into an electric utility's portfolio. For example, wind is an intermittent resource, yet the DOE reports that as of 2011 year-end, installed wind capacity in the United States totaled approximately 47,000 MW. 29 states have installed more than 100 MW of wind capacity, and 14 states have installed more than 1,000 MW. The DOE's *2010 Wind Technologies Market Report* indicates that the costs of integrating wind at capacity penetrations of as much as 40% of system peak load are estimated to be below $10/MWh, and required increases in balancing

B. DEC and PEC have ramped up deployment of renewables in recent years, with minimal cost increases to ratepayers.

DEC and PEC have demonstrated that renewable energy resources are available and can be developed at a reasonable cost, with minimal impact on rates. Over the past several years, DEC and PEC have procured a variety of resources to comply with the REPS, including solar, biomass, eligible hydro, wind, and energy efficiency.[54] Both utilities have complied with the general REPS obligations as well as the solar set-aside requirements and have also been able to bank renewable energy certificates ("RECs") for retirement in future years. Although a portion of their compliance obligation has been satisfied by the purchase of off-system RECs, a significant share represents renewable energy generated and delivered to the DEC and PEC systems.

The REPS has had little impact on the rates of North Carolina utility customers. As illustrated in Table 11 below, DEC and PEC have consistently met REPS targets within the annual cost cap. Both utilities forecast a decrease in their REPS charge even as they make progress towards increasing compliance obligations.

Table 11: Annual Residential Class REPS Charge v. Cost Cap[55]

	2010	2011	2012	2013
PEC	$7.80	$6.96	$6.72	$4.92
DEC	$1.92	$3.24	$5.88	$2.64
Annual Residential Cost Cap	$10.00	$10.00	$10.00	$12.00

Source: REPS Cost Recovery Filings, NCUC Docket Nos. E-7, Sub 872, 909, 936, 984, 1008 and Docket Nos. E-2, Sub 948, 974, 1000, 1020.

reserves to back up wind capacity are modest as well. Wiser & Bolinger, *2010 Wind Technologies Market Report*, pp. 67-71 (June 2011).

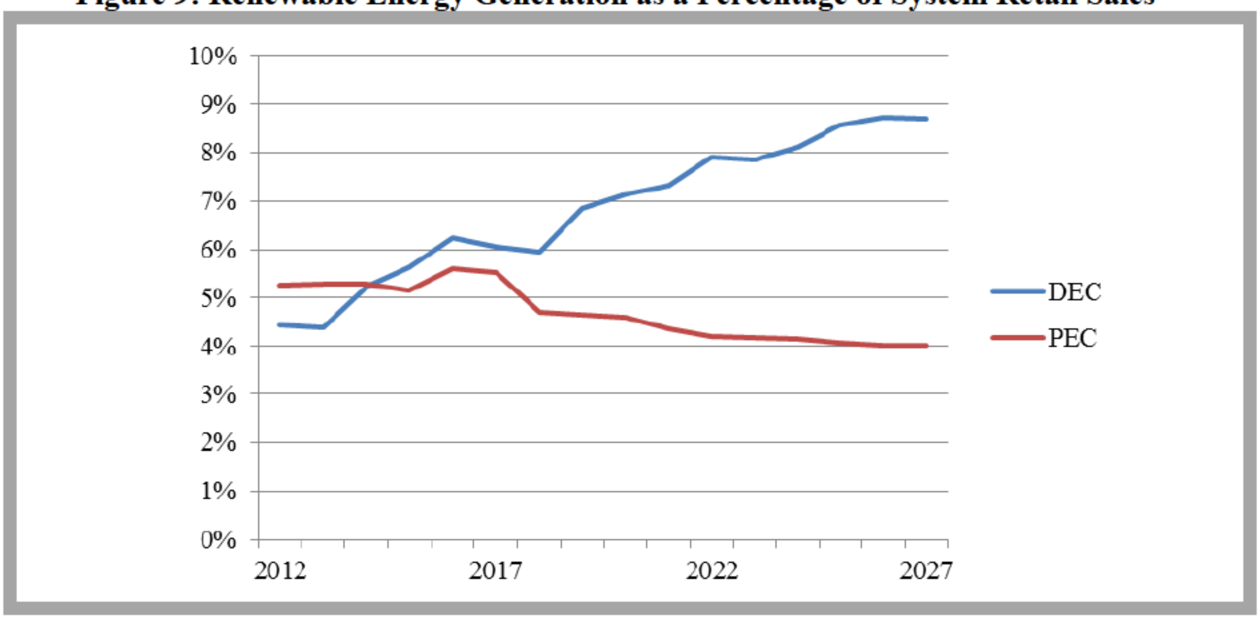
[54] *See* DEC's 2012 REPS Compliance Plan, NCUC Docket E-100, Sub 137, 2012 PEC IRP at D-3, *and* Direct Testimony and Exhibits of Jennifer Ellis & REPS Compliance Report, NCUC Docket No. E-2, Sub 1020 (June 4, 2012).

[55] REPS Cost Recovery Filings, NCUC Docket E-7, Subs 872, 909, 936, 984, 1008 and Docket E-2, Subs 948, 974, 1000, 1020.

1. <u>DEC's IRP shows a greater commitment to renewable energy generation than PEC's IRP.</u>

Neither DEC nor PEC forecasts renewable energy to become a major element of its energy or capacity strategy over the next 15 years. DEC's RE strategy is primarily driven by the REPS, as well as an expectation of potential federal or South Carolina legislation. DEC 2012 IRP at 59.[56] PEC appears to employ a similar strategy, as its current long-term plans for renewable resource deployment are limited to existing renewables contracts for NC REPS compliance. PEC 2012 IRP at 18-19. As illustrated in Figure 9 below, DEC's 2012 IRP indicates a modest increase in renewable energy generation, and PEC's 2012 IRP indicates a slight decrease in renewable energy generation.

Figure 9: Renewable Energy Generation as a Percentage of System Retail Sales[57]



[56] DEC made similar statements in its 2009, 2010, and 2011 IRPs.
[57] Source: DEC: Projected generation from DEC portfolio analysis outputs; system retail sales projections from DEC 2012 IRP at 128; expected energy savings from DEC 2012 IRP at 25, 27. (Note that hydro generation from existing facilities, although generally not eligible for REPS compliance, is included for illustrative purposes and accounts for [redacted] each year during this time period.) PEC: Projected generation from PEC portfolio analysis outputs; system retail sales projections from PEC 2012 IRP at 9.

DEC's greater emphasis of on-system, self-build resources for REPS compliance is illustrated by the utilities' respective capacity plans. DEC plans to have approximately 970 MW of nameplate renewable capacity interconnected to its system by 2021, growing to approximately 1,665 MW by 2032. DEC 2012 IRP at 60. As illustrated in Figure 10 below, this capacity is expected to lead to an increase in system generation consisting of wind, solar, and biomass resources. DEC's system sales forecast for 2012 is approximately 80,000 GWh, which is expected to grow to about 104,000 GWh by 2027. IRP at 121. As a percentage of system sales, DEC's renewable energy generation is projected to grow from about [redacted]

Figure 10: Projected Renewable Energy Generation on DEC's System from 2012 IRP "Preferred Plan"

[redacted]

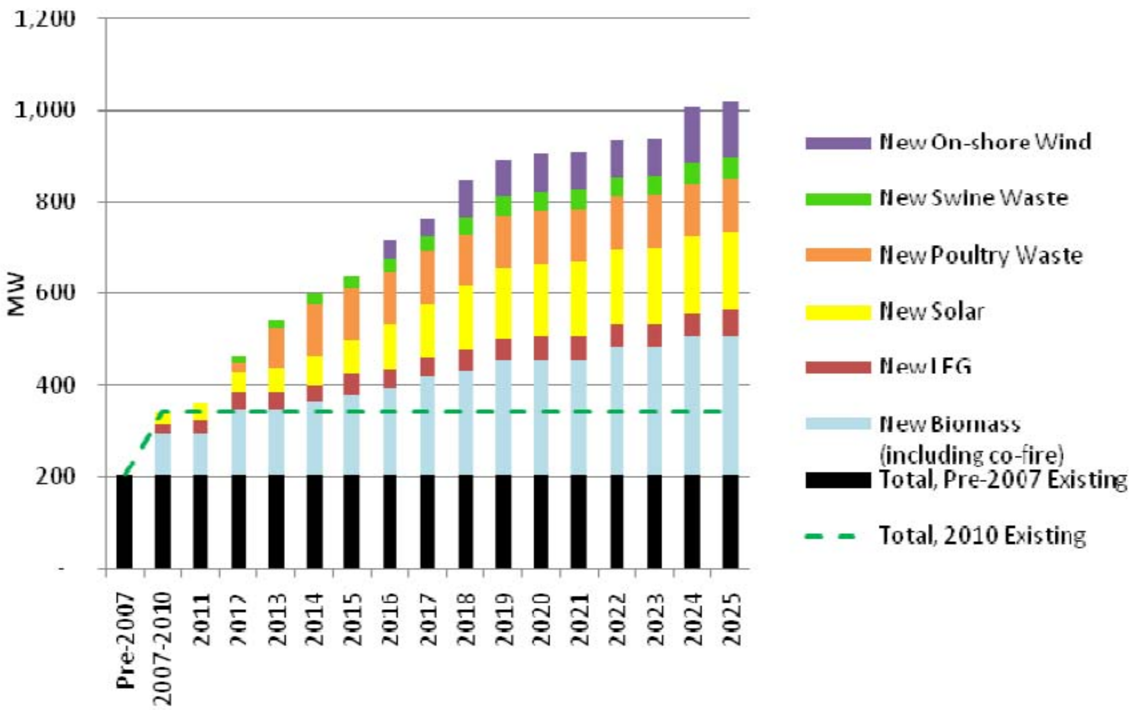
In contrast, PEC designates roughly 300 MW nameplate renewable capacity as part of its planned resource portfolio by 2017, declining to less than 250 MW by 2027. PEC 2012 IRP at 18, A-14. PEC's system retail sales forecast for 2012 is approximately 44,000 GWh, which is expected to grow to about 54,000 GWh by 2027. PEC 2012 IRP at 9. As illustrated in Figure 11, PEC model data indicate that renewable energy generation is forecast to decline in absolute terms over the next 15 years after a brief increase. As a percentage of system retail sales, PEC's renewable energy generation is projected to decline from about [redacted] today to about [redacted] in 2027.

Figure 11: Projected Renewable Energy Generation on PEC's System from 2012 IRP "Optimal Plan"

[redacted]

Although the two utilities are projecting distinctly different paths to compliance, their capacity and energy plans are broadly consistent with the findings of a recent report by La Capra Associates. La Capra forecasts that "more than 1,000 MW will be online to comply with REPS" by 2025, as illustrated in Figure 12.

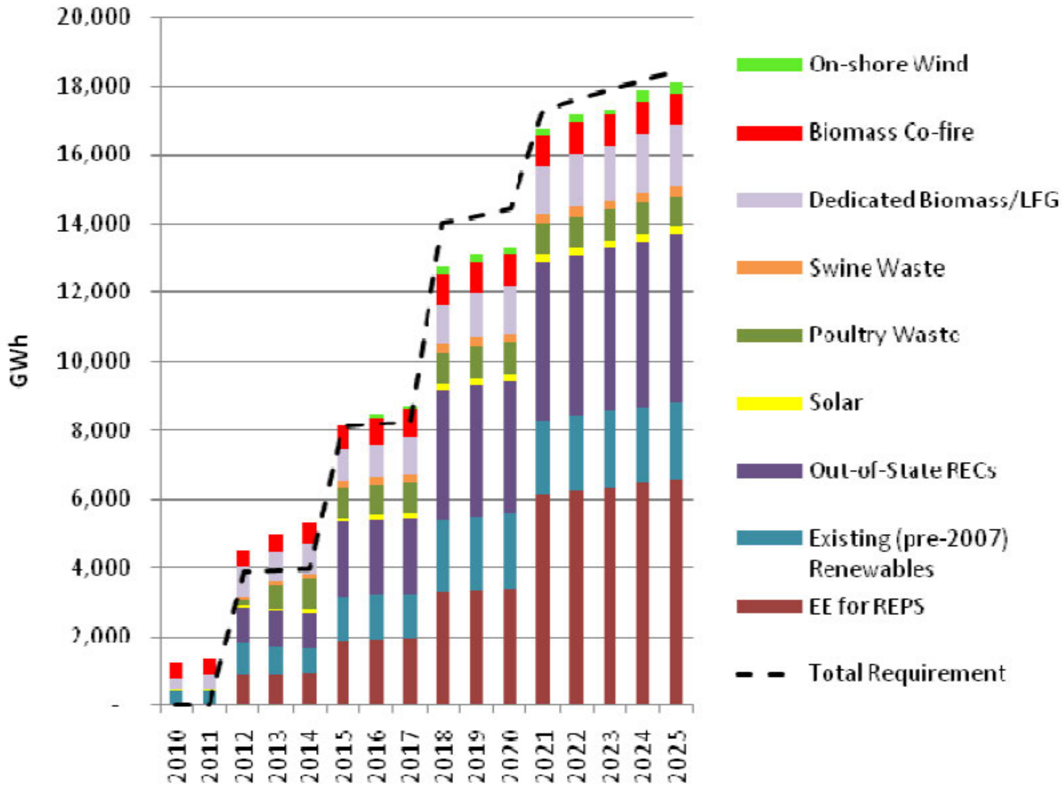
Figure 12: North Carolina REPS Compliance Capacity, La Capra Forecast



Source: La Capra Associates. North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives (June 2011) , at 51.

The DEC and PEC renewable generation resource forecasts are also consistent with La Capra's forecast of generation from new renewable energy resources, illustrated in Figure 13. La Capra's long-term forecast of new renewable energy generation is quite similar to the sum of new renewable energy generation modeled for the 2012 DEC and PEC IRPs.

Figure 13: North Carolina REPS Compliance Sources, La Capra Forecast



Source: La Capra Associates. North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives (June 2011) , at 52.

Furthermore, there is enough renewable energy resource potential in the Carolinas to support greater deployment of renewables than indicated in either utility's 2012 IRP. For example, La Capra estimated a practical potential of 4,000 MW of onshore wind, biomass, and hydropower resource opportunities in North Carolina, plus an "unlimited" practical potential for solar resources.[58]

Leading utilities have demonstrated that renewables can be integrated into resource portfolios at substantially faster rates than represented in the current DEC and PEC IRPs. PacifiCorp, for example, added over 2,100 MW nameplate wind capacity to

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[58] La Capra Associates. North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives(June 2011), at 2.

its system via company-owned facilities and power purchase agreements from 2002 to 2012.[59] Assuming these facilities operate at a 30% capacity factor, their energy contribution represents approximately10% of PacifiCorp's projected 2012 system retail sales.[60] As shown in Figure 9, above, over a comparable period of time, DEC appears to be planning to grow its portfolio share of renewable energy by [redacted] and PEC's share of renewable energy actually declines.

One reason that PEC's 2012 IRP forecasts less growth in renewable energy than DEC's is that PEC lacks a long-term REPS compliance plan. In response to a data request for the company's current compliance forecast over the 15-year planning horizon, PEC explained that:

> [F]uture compliance efforts may include energy efficiency, out-of-state RECs, and other RECs from resources which may or may not contribute energy and capacity. Thus, exactly how all the requirements of the REPS will be achieved, and through which technologies, is not fully known at this time. For resource planning purposes and given the uncertainty associated with the renewable resources that will ultimately be needed for compliance with the North Carolina REPS, PEC has only reflected committed renewables and some potential contract extensions.[61]

PEC is able to create a long-term plan for conventional supply-side investments, despite the significant risk and uncertainty involved in developing conventional generating plants. PEC 2012 IRP at 5. Similarly, PEC can and should develop a long-term REPS compliance plan.

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[59] *See* PacifiCorp 2011 Integrated Resource Plan, Volume I at 87. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

[60] System retail sales projection from Pacificorp 2011 Integrated Resource Plan, Volume II at 1 (available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-Appendices_Vol2-FINAL.pdf); 1% energy savings were assumed based on Pacificorp 2011 IRP, Volume I at 13.

[61] PEC response to SACE DR No. 21.

2. DEC and PEC's long-term NC REPS compliance plans appear to depend in part on [redacted], which reduces the system benefits of renewable energy resources.

Despite initial efforts at DEC and PEC to develop renewable resources as a significant component of their overall IRPs, the companies' mid- to long-term plans appear to rely in part on [redacted], and in general are overly cautious compared to renewable resource deployment trends at leading electric utilities. Untapped renewable resources exist in the Carolinas at levels that could support increases in the utilities' projected company-owned renewable facilities and/or renewable resource PPAs.[62] For example, recent renewable resource potential studies for North and South Carolina identified nearly 1,000 MW nameplate capacity potential for onshore wind alone.[63]

In the outer years of the IRP planning horizon, substantial gaps seem to exist between [redacted].[64] These gaps are likely to be filled by maximizing both efficiency-derived RECs and unbundled REC purchases. Because REC markets are well developed outside of the Carolinas, for example in states such as California and Texas, the companies may derive the majority of their unbundled REC shares from out-of-state RECs. Both utilities already have heavily

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[62] *See* Black & Veatch, South Carolina Resource Study, at 1-4, January 2012, http://www.scstatehouse.gov/committeeinfo/EnergyAdvisoryCouncil/ResourceStudyComments/SCEACResourceStudy_FINAL.pdf; La Capra Associates, North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives, at 34, June 2011,http://www.lacapra.com/downloads/NC_EPC_REPS_Report2011.pdf.

[63] *Id.*

[64] The REPS requirements are estimated to escalate over time to approximately 9% of DEC's system retail sales in 2021 and beyond, and approximately 10% of PEC's system retail sales in 2021 and beyond. [redacted] Percentages based on (1) REPS obligation data from DEC 2012 REPS Compliance Plan at Exhibit A and NCUC Docket E-2 Sub 1020, Direct Testimony of PEC witness Jennifer Ellis, Ellis Exhibit 1; and (2) system retail sales data (excluding energy savings from efficiency programs) from DEC 2012 IRP at 128, 25, 27 and PEC 2012 IRP at 9.

utilized efficiency-derived RECs and have purchased out-of-state RECs for retirement and banking purposes. A 2011 La Capra Associates analysis, which examined NC REPS compliance to date and resource options for future compliance, projected that from 2010 to 2025 power providers subject to the NC REPS will have collectively procured more than half of their RECs from efficiency savings and out-of-state unbundled RECs.[65]

DEC and PEC should aggressively pursue cost-effective energy savings opportunities. The utilities should also endeavor to comply with the NC REPS targets in a way that minimizes costs, while also maximizing benefits to ratepayers. Renewable energy that is delivered to the DEC and PEC power grids has unique value to the utility and its customers, as discussed in detail below. Consideration of renewable energy resources on an equivalent basis with other supply-side resources, as discussed below, could yield benefits by shifting NC REPS compliance strategies away from [redacted] and towards greater deployment of company-owned renewables or bundled power and REC contracts.

3. <u>Options for PEC to improve its renewable energy planning.</u>

While PEC included its renewable energy compliance forecast in its resource plan, PEC did not consider renewable energy resources to help meet energy or capacity needs in any sensitivity or scenario modeling. PEC included only natural gas and nuclear energy resources in its alternatives analysis. PEC 2012 IRP at A-3. Even though PEC states that it is "constantly evaluating options to meet its overall [REPS] requirements," 2012 PEC IRP at D-2, PEC does not evaluate renewable energy as a resource option apart from the REPS.

[65] La Capra Associates. North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives, at 2 (June 2011).

One shortcoming of PEC's renewable energy resource planning is that it does not appear that PEC has conducted or commissioned its own study of renewable resource potential. In response to a data request for assessments of renewable resource potential and costs in the Carolinas recently prepared by or for the company, PEC provided reports estimating state-level resource potential and costs by NREL, La Capra Associates, and the University of North Carolina at Chapel Hill.[66] While these assessments are useful for general guidance, they are not specific to PEC's service territory and do not contain analyses that could serve as the basis of a REPS compliance strategy.

PEC does describe various renewable resources within its generation alternatives screening discussion, and includes several renewable technologies in its levelized busbar curve analysis. PEC 2012 IRP at 11-17. With respect to solar energy, PEC's costs appear high. According to data supplied by PEC and DEC, PEC assumed a cost of [redacted] per kW, compared to the DEC estimate of [redacted] per kW.[67] DEC's estimate is more reflective of widely-quoted cost estimates, and PEC's roughly [redacted] cost premium is large enough to affect the outcome of a screening analysis.

In addition to premium cost estimates, PEC's decision to limit analysis of renewable resources to the busbar technique fails to consider the impact of renewable energy resources on total fuel and O&M costs in shaping the overall resource plan.[68] PEC states that wind and solar projects, although "currently not viable options for making

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[66] PEC Response to SACE Data Request No. 1-19.
[67] PEC and DEC responses to informal data request.
[68] PEC has explained that the busbar curve technique "compares the cost of capital, fuel and non-fuel operation and maintenance expense ('O&M') of the alternative over a range of capacity factors, without consideration of how the alternative might operate as part of the system and impact total fuel and O&M costs." Progress Energy Carolinas, Inc.'s Resource Planning Philosophy Concerning Purchased Power at 2, North Carolina Utilities Commission Docket No. E-100, Sub 118 (filed August 31, 2009). PEC incorporated this power purchase methodology discussion by reference into its 2012 IRP. *See* PEC 2012 IRP at 24.

significant contributions to *reserve* requirements due to their relatively high cost and intermittent operating characteristics … will play an increasing role in PEC's *energy* portfolio through PEC's renewable compliance program." PEC 2012 IRP at 12 (emphases in original).[69] Considering energy resources is critical in a capacity plan to accurately assess the overall value of each resource to the utility and its customers, particularly given that energy generated from renewable resource facilities tends to displace fossil fuel generation on utility systems.

In contrast, in response to a similar data request, DEC provided detailed internal analyses that included [redacted].[70] As discussed below, DEC did include renewable resources in its model analysis to a limited extent. An analysis of resource availability and cost based on responses to PEC's RFPs and other internal market data could benefit PEC and its customers by further reducing future compliance costs.

4. <u>DEC's modeling of renewable energy resources is distorted by interactions with other resources and risks.</u>

In contrast to PEC, DEC evaluated renewable energy resources as part of its quantitative analysis for the 2012 IRP. However, the evaluation was limited to the screening analysis; DEC constrained the final PVRR analysis to be generally limited to levels of renewable energy required to meet the REPS. Explaining this decision, DEC

[69] It appears that PEC assigns some capacity value to intermittent renewables, in addition to the energy value of these resources. In response to a data request, PEC stated that "For screening purposes, PEC assumes the capacity credit for 'on-shore' wind to be 18% and for 'off-shore' wind to be 28% of nameplate ratings. The capacity credits are based on the calculated hourly output of hypothetical wind turbines over the top 20% of load hours (most of which are during the summer) since that is when the majority of the loss of load hours are expected." PEC response to SACE Data Request No. 1-24.

[70] DEC response to SACE DR No. 21.

asserts that "the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels, *unless incentivized with state and federal tax incentives*." IRP at 60 (emphasis added). This assertion overlooks the fact that DEC's screening model selected [redacted],[72] neither of which included [redacted]. Despite the fact that DEC's screening model selected significantly [redacted] designated as necessary to meet REPS requirements, these resource levels were not analyzed in the final PVRR analysis stage. Instead, in both the base and high fuel cases utilized for the PVRR analysis, DEC evaluated [redacted] it had designated for REPS compliance. DEC 2012 IRP at 61.

DEC did evaluate higher levels of renewable energy resources than necessary to comply with the REPS in a few of its sensitivity analyses. However, the company did not clearly describe these different levels of renewables, or the reasons for the variation, in the IRP. DEC 2012 IRP at 109. Moreover, these sensitivity analyses were distorted by various complicating factors.

In the CES sensitivity, for example, DEC assumed an alternative compliance payment of $30/MWh and included nearly all of its planned resource acquisition within the scope of "Clean Energy." *Id.* at 107. As a result of these inputs, the model data indicated a significantly higher level of renewable energy generation for the CES

[71] The [redacted] resources correspond to approximately [redacted] nameplate capacity.
[72] In response to a data request, DEC stated that in its screening analysis, "renewable energy resources were not selected as their costs remain higher than traditional supply side resources." DEC Response to Petitioners Data Request No. 25. However, DEC selected nuclear resources for extensive quantitative analysis even though lower cost combined cycle gas plants were selected in the base case screening analysis.

sensitivity relative to the base case in the gas portfolio, but not in either nuclear portfolio. Because nuclear generation is part of the specified capacity expansion plan in the nuclear portfolio CES sensitivity, it appears that renewable energy generation did not "compete" with nuclear in those sensitivity models. Also, as noted in Attachment 1, DEC reported the model data for the CES sensitivity in energy terms (not capacity terms as it did with other sensitivity model data), and it is therefore unclear how much additional on-peak capacity the model selected for the CES analyses.

Another example of a sensitivity analysis with distorted results due to confounding factors is DEC's [redacted] sensitivity analysis.[73] In this sensitivity, which DEC does not describe in the IRP, levels of wind and solar generation were [redacted] than in the base case for all three resource portfolios. However, in addition to [redacted] of EE/DSM and renewable energy, this scenario also had a [redacted] carbon price, resulting in a financial model that is distinct from the High EE/DSM and CES sensitivities. As a result, unlike any other analysis with higher levels of EE/DSM and renewable energy, this sensitivity results in a [redacted] Moreover, coal unit performance metrics in the [redacted] in ways that are not explained by [redacted], nor by [redacted].

In future resource planning, DEC should select model portfolios that provide the company with meaningful information on how increased levels of renewable energy would affect its costs and other system resources, including sensitivities regarding the

[73] DEC response to SACE Data Request 1F.

cost of renewable energy and its interaction with other supply-side and demand-side resource opportunities.

C. DEC and PEC do not evaluate the opportunity for renewables to reduce system cost risk in a comprehensive manner.

As discussed above, renewable resources impart distinctive benefits to utility resource portfolios, and must be evaluated using analytical approaches that are capable of capturing these important benefits. Both DEC and PEC recognize that in addition to cost, resource planning considers the risk that certain external constraints or market forces may affect some resource options more than others. All other things being equal, less risky resources should be preferred. Like EE/DSM resources, renewable resources are less risky than conventional supply-side resources, in terms of fuel costs, environmental costs, scheduling inflexibilities, and implementation failure.

Since PEC only analyzed renewable resources using busbar cost comparisons, its IRP does not provide a clear assessment of resource cost stability across different future scenarios. Similar to the lack of a system cost assessment of renewable energy resources, PEC's IRP modeling fails to assess renewable resources for system risk impacts. And neither DEC nor PEC evaluate renewable resources in comparison to conventional supply-side resources with respect to environmental costs, scheduling inflexibilities, or implementation failure.

Since DEC does provide a limited amount of cost and risk assessment for renewable energy resources, the following discussion of DEC's analysis of solar and woody biomass illustrates the ways in which DEC and PEC could improve consideration of renewables to account for both cost and risk.

Solar energy. As illustrated in Figure 14, DEC's renewable energy assessment identifies the potential that solar energy power purchase agreements ("PPAs") will be cost-competitive with conventional generation resources. Costs associated with new DEC-owned gas resources will be roughly [redacted] generated in 2020, including both combined cycle and peaking gas plants. In comparison, DEC's solar model suggests flat PPA prices of [redacted] per MWh in 2020, as illustrated in Figure 14. The [redacted] of the cost ranges for [redacted] development suggests that DEC should evaluate the range of costs for solar energy just as it does for other supply-side resources.

Figure 14: Internal DEC Resource Assessment Reflects [redacted]

[redacted]

[redacted] The figure was derived from DEC's response to data request no. 2. (Duke Energy, "Renewable Resource Assessment" (Q2 2011).)

Figure 15: Internal DEC Resource Assessment Reflects [redacted][75]

[redacted]

Solar energy generally has negligible or low risks, for three main reasons: it has no fuel costs; there is a robust market for solar procured under contract; and solar contracts typically have fixed delivery charges. Solar is, however, subject to uncertainty regarding the extension of tax credits. As illustrated in Figure 15, this [redacted]. This type of risk can and should be analyzed within DEC and PEC's resource planning framework. Viewed from

[75] The figure was derived from DEC's response to Source: Duke Energy, "Renewable Resource Assessment" (February 23, 2012). [RESPONSE 20 CONFIDENTIAL]

both a cost and risk perspective, DEC's internal assessment of solar energy resources seems to belie the limited consideration of solar energy in the detailed quantitative analysis phase of both DEC and PEC's resource plans.

Woody biomass. In contrast to its 2011 IRP, DEC did not consider a baseload woody biomass resource in its 2012 IRP quantitative analysis. In response to a data request, DEC explained:

> Landfill gas was the only baseload biomass option utilized in the screening process for several reasons. First, in the technology screening process, as indicated in Appendix A of the 2012 DEC IRP, landfill gas represented the most economical option of the renewable energy resources that were screened. Second, DEC has contracted with several landfill gas bidders to meet its REPS requirements. From experience, DEC has found landfill gas to be a reliable, cost-effective, and low risk renewable energy resource. Third, there are several publicly discussed risks to woody biomass resources including the carbon neutrality of the resource, and the limitations to fuel supply. Therefore, a woody biomass resource was not included in the screening process for the 2012 DEC IRP. DEC will continue to monitor these issues going forward. As the certainty regarding the fuel supply, carbon neutrality, and sustainability of the resource are determined, DEC will determine the feasibility of including these resources in future IRP analyses.[76]

In this response, DEC provides a clear explanation for eliminating consideration of baseload woody biomass technology in the resource screening phase, and a clear set of qualitative criteria for reconsidering this resource in the future. This evaluation is an example of a robust, defensible evaluation of a particular resource which could be applied by both DEC and PEC to other resources.

DEC and PEC can and should conduct a more extensive analysis of renewable energy resources. DEC and PEC's IRPs suggest that their renewable resource acquisitions are for the most part driven by current and anticipated statutory

[76] DEC Response to SACE data request, question 25.

requirements. However, neither utility comprehensively evaluates the option of deploying more renewable energy resources than statutorily required. The quantitative analyses performed by DEC and PEC fail to capture the value added by renewable resources, because the option to develop renewable capacity beyond statutory requirements is screened out before the analytical stage at which the value of these attributes would be most evident—the modeling stage in which the cost of candidate portfolios is estimated across a range of possible future scenarios.

As a first step to capturing the full value of renewable resources, DEC and PEC should evaluate one or more candidate portfolios that incorporate more renewable energy and capacity than strictly necessary to comply with the REPS. Such an evaluation would put renewables on an equal footing with conventional supply-side resources, given that a candidate portfolio featuring aggressive renewable resource deployment would be evaluated on an equal basis with DEC and PEC's standard gas-focused and nuclear-focused portfolios in the final, scenario-based PVRR analysis. One way to do this would be to test a "High DSM/High Renewables" candidate portfolio across multiple sensitivities, as is currently done for nuclear- and gas-focused candidate portfolios.[77] Evaluation of one or more high renewables candidate portfolios across all sensitivities would highlight the ability of low-risk renewable resources to provide cost stability to

[77] The Arizona Public Service Company ("APS") and Tennessee Valley Authority ("TVA") are two noteworthy examples of utilities that evaluate "High Renewables" candidate portfolios as part of their quantitative IRP analysis. APS models a candidate portfolio that includes procurement of significantly more renewable capacity than needed to meet the state's RPS, and both utilities evaluate High Renewables portfolios across multiple future scenarios in order to capture renewable resource benefits beyond energy and capacity contributions. Arizona Public Service Company, 2012 Integrated Resource Plan, March 2012, http://www.aps.com/_files/various/ResourceAlt/2012ResourcePlan.pdf (High RE descriptions at 4); Tennessee Valley Authority, Integrated Resource Plan: TVA's Environmental & Energy Future, March 2011, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf (High RE descriptions at 99).

utility portfolios across many possible futures. This analytical approach would allow DEC, PEC, the Commission, the Public Staff, and other stakeholders to more fully understand the value renewable resources can offer beyond basic energy and capacity contributions.

VI. THE COMPANIES' REVISED RESERVE MARGINS APPEAR REASONABLE, BUT DEC'S MARGIN MAY STILL BE TOO HIGH IN LIGHT OF ITS TREATMENT OF DEMAND RESPONSE.

DEC and PEC have adopted revised reserve margins that appear reasonable. DEC lowered its reserve margin from 17% to 15.5%, and PEC increased its minimum reserve margin from approximately 14% to 14.5%, both based on recent reserve margin studies conducted by Astrape Consulting, LLC. As explained the IRPs, each study was performed to comply with the Commission's order in the 2010 IRP docket, which directed DEC and PEC to perform a comprehensive analysis of their respective reserve margins and to include the studies as part of their 2012 IRPs.[78] These new reserve margins appear reasonable when compared to reserve margins used by comparable utilities; for example, using a different method, South Carolina Electric and Gas Company ("SCE&G") has updated its reserve margin to 14%. 2012 SCE&G IRP at 25.[79]

Although DEC's 15.5% reserve margin appears reasonable on its face, the company's treatment of demand response raises concerns that DEC may be planning for excessive reserves. Astrape conducted both the DEC and PEC study; however the treatment of demand response—specifically whether it requires backstand reserves—in

[78] Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans at 7, NCUC Docket No. E-100 Sub 128 (Oct. 26, 2011); *see also* 2012 PEC IRP at 21; 2012 DEC IRP at 85.
[79] *See* South Carolina PSC Docket No. 2012-9-E.

the studies differed.[80] In the PEC study, demand response is treated as a load adjustment, which does not require its own reserve requirement. In the DEC study, demand response is treated as a resource option with its own reserve requirement, thereby increasing the reserve capacity.[81]

For purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by the North American Electric Reliability Corporation ("NERC"), net internal demand includes unrestricted non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load ***and demand response***.[82] PEC's method of accounting for demand response by adjusting load appears to be more consistent with NERC guidance than the method chosen by DEC.

In response to prior criticism of its methodology, DEC stated that some of its demand response programs "require either communication with the customer, customer acceptance at the time of peak, or the reliance on aging infrastructure," with these technical issues resulting in "less demand reduction than anticipated" and therefore necessitating backstand reserves.[83] NERC guidance supports consideration of these factors, indicating that demand response programs should be considered in net internal demand to the extent that they are dispatchable and controllable.[84]

DEC data do not indicate that such technical issues are actually impairing the dispatchable and controllable nature of the company's programs. In fact, DEC reports

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[80] Demand response is sometimes referred to in IRPs using the normally more general term "demand side management."
[81]Astrape Consulting, *Duke Energy Carolinas 2012 Generation Reserve Margin Study* (June 2012).
[82] NERC, *Reliability Assessment Guidebook*, Version 3.1 (August 2012).
[83] DEC Reply Comments on 2011 IRP, NCUC Docket No.E-100, Sub 128 (Jan. 27, 2012) at14.
[84] *Supra* note 74 at 15.

that its demand response programs have been activated a number of times, and most programs have achieved reductions consistent with (or even in excess of) expected reductions.[85] 2012 IRP at 148. Based on these data, it appears that, overall, DEC's demand response programs are dispatchable and controllable. Indeed, Astrape modeled these resources without remarking on any technical issues that might suggest a backstand reserve requirement.[86] While technical issues may exist that result in less demand reduction achieved than expected, the activation history data do not suggest such issues are significant.

With the exception of the PowerManager (air conditioner) program, DEC should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand. This would align DEC with the most straightforward interpretation of NERC guidance as well as with method used by PEC.[87] 2012 PEC IRP at 26. With respect to the recent performance of its air conditioner demand response program only, its recent performance suggests that DEC should either model the program as a resource (which would require average backstand of 15.5%) or adjust the expected reduction to reflect the results of recent activations. If DEC applies NERC guidance, the reserve margin requirement would decrease by 93 MW by 2017 (roughly 15.5% of the

[85]The sole exception is the Power Manager (air conditioner) program, in which activation events since 2010 achieved 3-17% less reduction than expected.

[86]*Supra* note 73 at 33-34, 47-48. For example, Astrape modeled various sensitivities reflecting general operational concerns affecting reserve margin planning, such as weather diversity. None of these sensitivities reflected general technical considerations related to the response of demand response resources.

[87]PJM is another example of a utility system that calculates its reserve margin after subtracting energy efficiency and demand response resources. *See, e.g.*, Summer 2012 PJM Reliability Assessment presented to Pennsylvania Public Utility Commission (June 7, 2012) at 4-5, available at http://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2012-PJM.pdf.

demand response programs other than Power Manager). This would reduce costs to customers by tens of millions of dollars.

An additional, related issue is that it is unclear whether DEC adjusts net internal demand to account for its demand response programs that use rate signals to reduce on-peak energy use, such as Residential Time-of-Use and Hourly Pricing for Incremental Load. DEC 2012 IRP at 31. These programs are not included in the reserve margin calculation (see Tables 4A, 4B, 4D, and 8A). *Id.* at 39-41, 93-95. They may be accounted for in other aspects of the load forecast, but if so, this is not described in the IRP. If the load impacts of these programs are significant, but not accounted for in the load forecast, then DEC should account for these resources in future IRPs to the extent that it would result in a significant impact on capacity requirements.

VII. THE IRPS DO NOT CLEARLY REFLECT A RIGOROUS EVALUATION OF THE ECONOMICS OF CONTINUING TO OPERATE SCRUBBED COAL UNITS

Both DEC and PEC are in the process of retiring their oldest, dirtiest coal plants. DEC is already taking steps to retire some of the oldest, highly polluting coal units on its system: Buck Steam Station Units 3 and 4 were retired in May 2011, Cliffside Units 1 through 4 were retired in October 2011, and Dan River Units 1 and 2 were retired in April 2012. DEC 2012 IRP at 54. DEC announced on February 1, 2013 that the company is accelerating the retirement of Buck Units 5 and 6 and Riverbend Units 4-7 from April 1, 2015 to April 1 of this year.[88] According to the company's IRP, DEC plans to retire all of its remaining coal units that lack modern sulfur dioxide pollution controls

[88] *See* Duke Energy news release, available at http://www.duke-energy.com/news/releases/2013020101.asp

(flue gas desulfurization units or "scrubbers") by 2015. DEC 2012 IRP at 55.[89] PEC's 2012 IRP likewise includes retirement of all of its remaining coal units that lack scrubbers: Lee Units 1-3 in September 2012, Cape Fear Units 5 & 6 and Robinson Unit 1 in October 2012, and Sutton Units 1-3 in December 2013.[90] PEC 2012 IRP at B-6.

The retirement of these highly polluting, "unscrubbed" coal units makes clear economic sense in light of increasingly stringent environmental regulations, low natural gas prices and other factors. The factors apply to scrubbed units as well. Scrubbed units face many of the same risks as the unscrubbed units that DEC and PEC are planning to retire—yet neither company's 2012 IRP reflects a rigorous evaluation of the economics of continuing to operate scrubbed coal units.

The U.S. Environmental Protection Agency ("EPA") has recently issued, or is poised to issue, several new regulations to protect human health and the environment. Both DEC and PEC DEC recognize that these regulations, among other factors, will impact coal-fired power plants. PEC's IRP correctly notes that, in addition to uncertainty about factors such as fuel prices and the economy, "several existing and potential regulatory actions also present challenges to the planning process":

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[89]DEC has committed to retire coal-fired generation to resolve recent litigation. The Merger Agreement provides that DEC will retire coal-fired generation as provided by the terms and conditions of a separate settlement agreement that resolved the contested cases challenging the construction and operation permits for DEC Cliffside Unit 6, entered into between DEC and SACE, the Sierra Club, Environmental Defense Fund, National Parks Conservation Association, and the North Carolina Waste Awareness and Reduction Network, Inc. (the "Cliffside Agreement"). Under the terms of the Cliffside Agreement, DEC agreed to retire coal-fired electrical generating units, representing a total of 1667 MW of capacity, according to the following schedule: 1) 198 MW (total capacity of Cliffside Units 1-4) prior to commencing operation of Unit 6; 2) an additional 800 MW of capacity in three stages (350 MW by December 31, 2015, 200 MW by December 31, 2016, and 250 MW by December 31, 2018); and 3) an additional 669 MW by December 31, 2020.

[90]PEC has also agreed to retire coal-fired generation to resolve recent litigation. With regard to PEC, the Merger Agreement provides that PEC will retire coal-fired EGUs representing a total 1,533 MW(winter)/1,467 MW (summer) of capacity by December 31, 2015.

> These include potential federal environmental legislation dealing with regulation of carbon emissions including proposed Greenhouse Gas (GHG) New Source Performance Standards (NSPS), proposals for Federal renewable portfolio standards, the Environmental Protection Agency's (EPA) new Cross State Air Pollution Rule (CSAPR), the EPA Maximum Achievable Control Technology (MACT) rule (also known as the Mercury and Air Toxics Standards or MATS rule), the expected EPA 316b rule [regulations under Section 316(b) of the Clean Water Act governing cooling water intake structures], and the potential consideration of coal ash as hazardous waste by EPA.

2012 PEC IRP at 3. DEC's IRP also references these regulations, as well as the Clean Air Interstate Rule; new National Ambient Air Quality Standards for ozone, sulfur dioxide and fine particulate matter; and new steam electric effluent guidelines, including potential thermal discharge requirements. DEC 2012 IRP at 73-81. According to DEC, implementation of these regulations will increase the need for the installation of additional control technology or retirement of coal-fired generation in the 2014 to 2018 timeframe. *Id.* at 54.

Continued operation of scrubbed coal-fired units may be uneconomical due to major capital investments and/or increased operating expenses necessary to comply with these regulations. Yet the DEC 2012 IRP does not contain a detailed discussion (beyond a simple recitation) of the risks faced by the company's existing scrubbed coal plants, or any discussion of the implications of these risks at specific coal units. Appendix F to PEC's 2012 IRP discusses in some detail the regulatory risks faced by the company's scrubbed coal plants. PEC's 2012 IRP at F-1—F-7. The IRP only includes cursory references to the implications of these risks on the generating fleet, however:

- "PEC is reviewing the impacts of the CSAPR [the Cross-State Air Pollution Rule] on the generating fleet, and additional reductions may be needed at some of PEC's units." *Id.* at F-1.

- "The MATS [Mercury and Air Toxics Standards] rule may require additional emission controls at PEC's coal-fired facilities." *Id.* at F-2.

- "Should additional [sulfur dioxide] nonattainment areas be designated in PEC's service territories, PEC may be required to install additional emission controls at some of its facilities." *Id.* at F-3.

- Developments regarding greenhouse gas regulation "may require PEC to address GHG emissions in air quality permits," and potential federal GHG legislation and additional federal GHG regulation "could result in significant cost increases over time." *Id.* at F-4.

- EPA regulation of coal combustion waste under the Resource Conservation and Recovery Act will at a minimum require liners and groundwater monitoring; under a "hazardous waste" designation, "landfill siting, material handling, and transportation costs would be significantly greater" and "would also increase the quantity and cost of disposal (landfill) and ash pond closure." *Id.* at F-4.

PEC's IRP does not go beyond these cursory references to discuss the implications of these regulations for specific coal units.

Compliance with new regulations will require additional pollution controls or other major capital investments, repowering, or retirement. DEC's and PEC's IRPs should reflect and report on each company's internal evaluation of whether it will be more economical to retire or repower scrubbed coal units, rather than investing significant capital in pollution control equipment and other infrastructure necessary to comply with impending regulations.

VIII. DEC'S AND PEC'S IRP DO NOT APPEAR TO EVALUATE FULLY THE RISK OF DELAYS AND COST INCREASES FACED BY NEW NUCLEAR PLANTS.

Both DEC and PEC include new nuclear generation in their 2012 IRPs. The companies' nuclear plans must be viewed in light of the history of nuclear power plant construction, which is riddled with instances of cost increases, schedule delays and plant cancellations.

Two of the three portfolios that DEC selected for detailed quantitative analysis included new nuclear generation: a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station, with units online by the summer of 2022 and 2024, and a "regional nuclear" portfolio consisting of 215 MW of nuclear by 2018, 730 MW in 2022 and 2024, and 558MW in 2028. DEC 2012 IRP at 11, 105. According to DEC, the regional nuclear portfolio is lower cost to customers in the base case and in most scenarios. The company chose the full nuclear portfolio for the 2012 IRP preferred plan, however, citing the lack of "firm commitments in place at this time for the regional nuclear portfolio." *Id.* at 12, 109.

Although PEC no longer includes a self-build nuclear option in the planning horizon, "Plan A," which PEC selected as its "preferred plan," includes the assumption that the company will acquire an ownership stake in nuclear units planned by other electric utilities in the region. Under this "regional nuclear" option, PEC explains that "the 2012 IRP assumes that PEC would take a five percent share of SCANA's V.C. Summer Units and 20 percent share of DEC's Lee units as represented in their respective 2011 IRPs." PEC 2012 IRP at 5. As discussed in a previous section, PEC developed four alternative plans in its sensitivity analysis that then were subjected to scenario analysis, plus an "Aspirational Plan" with higher levels of EE that was not passed on to the scenario analysis phase. *Id.* at A-3—A-5. Three of the four plans selected for scenario analysis included new nuclear generation: Plans A, C and D each include "regional" nuclear plants with PEC owning a 5% share of two units in 2017 and 2019 and a 20% share of a second pair of units in 2021 and 2023. *Id.* at A-4—A-5.

Neither DEC nor PEC demonstrates a significant cost advantage for nuclear as compared to gas (the only resource alternative given serious consideration). As illustrated in Figures 1 and 2, and Attachment 1, total costs varied by less than $0.1 billion for DEC and $1.0 billion for PEC among the alternative resource portfolios that were subjected to detailed quantitative analysis.

Furthermore, the use of present value revenue requirements for comparing the long-term cost of nuclear to that of gas obscures the shorter-term revenue requirement implications of nuclear power. For example, considering *only the first 20 years* of PEC's plans, relying on gas instead of nuclear to meet baseload needs results in plans that are over half a billion dollars less costly than plans relying on nuclear plants.[91] The shift of revenue requirements to earlier years in the planning period is driven by the capital-intensive nature of nuclear power.

PEC's preferred "regional nuclear" option is subject to many of the same risks and uncertainties as DEC's full ownership plan. DEC's Combined Construction and Operating license ("COL") application for the Lee Nuclear Station remains pending before the Nuclear Regulatory Commission ("NRC"). In April 2012, the NRC requested that DEC update the site-specific seismic analysis for the Lee Nuclear Station, pushing the online date for the new units beyond the summer peak of 2021. DEC reports in its IRP that the lead time for nuclear units is assumed to be 12-13 years or longer, and that "the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process." DEC 2012 IRP at 68.

[91] DEC and PEC responses to informal data requests. This is an illustration of the deceptive PVRR analysis rather than an endorsement of baseload gas expansion.

With regard to DEC's "regional nuclear" plans, DEC's IRP reports that the company has entered into an agreement with the Public Service Authority of South Carolina ("Santee Cooper") regarding the planned new nuclear reactors at V.C. Summer Nuclear Generating Station. Under the agreement, DEC is to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45% ownership of the new V.C. Summer units, which are scheduled to come online in 2017 and 2018.[92]

The new V.C. Summer units are still in the early stages of construction, having just received NRC approval in March 2012. The only other new nuclear construction project currently in process in the United States is Southern Company's Vogtle plant, which received NRC approval in February 2012 and as such is also many years from substantial completion. Given that these projects are the first new nuclear builds in the United States in decades, and considering the troubled history of U.S. nuclear construction, there is little certainty as to how the total costs and scheduling of these two plants will compare with the costs and schedules projected at the time of project approval. Thus, caution is warranted in estimating potential costs and construction lead times for new nuclear construction in DEC and PEC's nuclear portfolios.

Recognizing the possibility of escalating nuclear construction costs, DEC did evaluate a construction cost sensitivity in which the costs to construct a new nuclear plant were (+20/- 10%) relative to the base case. DEC 2012 IRP at 106. DEC states that the range used for the sensitivity analysis is based on the experiences of the Westinghouse/Shaw EPC consortium at Vogtle, V.C. Summer, and the four AP1000

[92]DEC has also entered into an option agreement with JEA, located in Jacksonville, Florida, in which JEA has option to purchase up to 20% of Lee Nuclear Station. IRP at 12.

units currently under construction in China, "as well as the recent trend in industry data of lower escalation rates."[93] Notably, none of these experiences reflect an operational facility.

Based on the complexity of nuclear plant construction, the history of significant cost overruns at nuclear plants (which in many cases greatly exceeded 20% in the U.S.), and the lack of recent data on U.S. nuclear construction, however, the (+20/- 10%) range may be overly narrow. Indeed, former Duke Energy Chief Operating Officer and Group Executive Vice President James Turner noted that it is not unreasonable for DEC to assume and plan for significant cost overruns, in the 40-50% range, for its proposed Lee units.[94]

In setting the nuclear capital cost sensitivity range for quantitative analysis, both DEC and PEC should give further consideration to the historical context of nuclear construction in the U.S. as well as the inconclusiveness of current U.S. nuclear projects regarding total cost outcomes. Given the significant uncertainties associated with nuclear construction, DEC and PEC should adopt broader, more conservative sensitivity ranges as DEC's and SCE&G's nuclear development plans unfold.

IX. PEC AND DEC SHOULD EVALUATE THE MACROECONOMIC IMPACTS OF THEIR RESOURCE PORTFOLIOS.

To assess the broader economic consequences of an IRP, it is important to examine the macroeconomic impact of the resource options, such as the impact on jobs and the regional economy. DEC states that its resource planning approach includes both quantitative analyses and qualitative considerations, such as "regional economic

[93]DEC Response to Informal Data Request No. 19.
[94] *See* DEC Reply Comments, Docket No. E-100, Sub 128 (March 1, 2011) at 32.

development considerations." DEC 2012 IRP at 7. However, its IRP does not include any discussion of the impact of its plan on the regional economy or employment, or any analysis to quantify this impact.[95] Both DEC and PEC should consider including such an analysis as part of the resource planning process.

Quantitative analyses may be used to estimate the impacts of resource planning decisions and energy policies on macroeconomic indicators such as employment, disposable income, and government revenue. For example, Clemson University researchers recently modeled the economic impacts of installation and operation of a large wind farm off the South Carolina coast.[96] The study found that the construction phase of the wind farm would have an average annual employment impact of 3,879 direct, indirect, and induced jobs and would generate $3.66 billion in output and $616 million in state and local government revenues. Operation and maintenance of the completed facility was estimated to have an average annual employment impact of about 678 total jobs.

Estimates of the employment impacts and other macroeconomic effects of individual projects, such as the wind farm project analyzed in the Clemson study, can also be performed as part of broader analyses that model development of full utility resource portfolios and that incorporate the effects of changing electric rates as utilities recover investment costs from ratepayers. The Michigan Public Service Commission, for example, helped to fund a recent study that utilized the REMI Policy Insight model[97] to

[95] DEC does discuss the economic impact of lower natural gas prices on its plan. DEC 2012 IRP at 10.
[96] Colbert-Busch, E., Carey, R.T. & Saltzman, E.W. South Carolina Wind Energy Supply Chain Survey and Offshore Wind Economic Impact Study (July 2012). Available at http://www.energy.sc.gov/publications/WindEnergyEconomicImpact7-2012FINAL.PDF.
[97] For a description of the REMI model, *see, e.g.* U.S. Environmental Protection Agency, *Assessing the Multiple Benefits of Clean Energy: A Resource for States*, 144, (Rev. Sept. 2011).

estimate and compare the macroeconomic impacts of several statewide electric sector resource portfolios, including impacts from construction of new generating facilities, deployment of energy efficiency programs, and the electric rate changes resulting from these utility investments.[98] The analysis compared a traditional fossil plant expansion strategy (the Base Case referenced in Table 12 below) to several alternative strategies featuring varying levels of energy efficiency and renewable resources. As Table 12 shows, in general, adding efficiency and/or renewables was projected to increase Michigan's gross state product ("GSP"), employment levels, and disposable income relative to the Base Case fossil portfolio. The greatest positive employment and GSP impacts occurred in the "Moderate EE + Moderate RE Case," where jobs increased by more than 17,000 and GSP increased by $1.1 billion relative to the Base Case.

Table 12: REMI Model Estimates of Macroeconomic Impacts of Michigan Resource Portfolios, 2007-2020

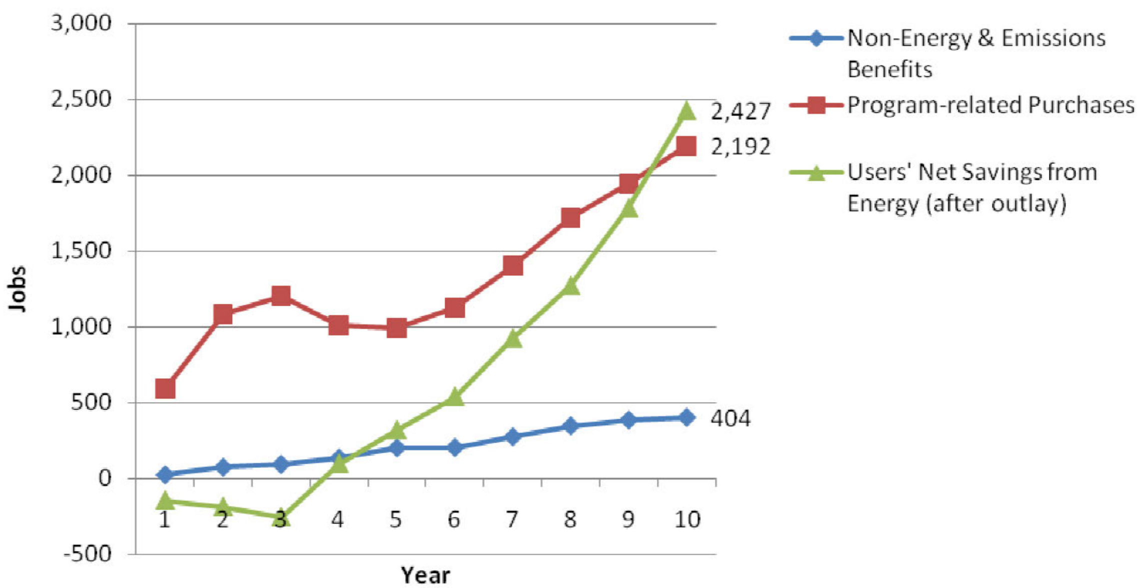
Scenario	**Gross State Product** (NPV Change from Base Case)	**Employment** (Change from Base Case)	**Real Disposable Personal Income** (NPV Change from Base Case)
Low EE	$553 million	8,783	$628 million
Low RE	$194 million	2,020	($229 million)
Low EE + RE	$750 million	11,204	$415 million
Moderate EE	$637 million	12,057	$904 million
Moderate RE	$533 million	6,381	($100 million)
Moderate EE + RE	$1,102 million	17,191	$664 million

A 2010 study on Wisconsin's energy efficiency and renewable energy programs further illustrates how the REMI Policy Insight model can be used to cover all aspects of economy development impacts, including changes in business sales, gross regional

[98] NextEnergy Center. A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan (April 2007). Available at http://www.michigan.gov/documents/deq/deq-ess-MichiganRPS-EE-FinalReport_193745_7.pdf.

product, real after-tax income, and jobs.[99] 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.[100] Figure 16 shows the REMI model estimates of the job impacts of Wisconsin energy efficiency and renewable energy programs.

Figure 16: REMI Model Estimates of Job Impacts of Wisconsin EE/RE Programs[101]



DEC and PEC could use similar methods to estimate and describe the macroeconomic consequences of the various portfolio options considered in their IRPs. Recently, La Capra Associates modeled an "encourage economic development" scenario for North Carolina as part of a study for the Energy Policy Council. The results suggested how a policy scenario to encourage economic development might affect

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[99] Economic Development Research Group, *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Wisconsin (March 2, 2010),http://www.focusonenergy.com/files/Document_Management_System/Evaluation/cy09economicimpactsreport_evaluationreport.pdf.
[100]*Id.*
[101]*Id.*

customer costs, rates, cost risk, and environmental impacts.[102] However, La Capra did not estimate the employment or economic development impacts of the modeled scenario. Doing so would help North Carolina's utilities leverage their resource investments to spur job creation and economic development, while keeping electric rates as low and stable as possible. With this information in hand, the Commission, customers and interested parties would be in a better position to understand the economic consequences of the various alternative plans analyzed in the IRPs.

X. PROCEDURAL MATTERS

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. Intervenor NCWARN, with support from Blue Ridge Environmental Defense League, has requested an evidentiary hearing in this proceeding. If the Commission allows NCWARN's motion, SACE and the Sierra Club respectfully submit the issues raised in the foregoing comments 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 and the Sierra Club recommend that the Commission convene 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

[102] La Capra Associates. North Carolina's Renewable Energy Policy: A Look at REPS Compliance To Date, Resource Options for Future Compliance, and Strategies to Advance Core Objectives (June 2011) , at 56.

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 working group to discuss and report on certain issues related to the IRPs and the resource planning process. SACE and the Sierra Club respectfully suggest 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 2013 annual reports and 2014 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.

XI. RELIEF REQUESTED

In light of the foregoing, SACE and the Sierra Club recommend that the Commission take the following actions:

1. Direct DEC and PEC to model energy efficiency on an equivalent basis to supply-side resources; for example, by adopting a two-supply-curve approach.

2. Direct DEC to distinguish between demand response programs that require backstand reserves and those that do not in its reserve margin analysis, and to apply its findings to its reserve margin calculation.

3. Direct DEC and PEC to analyze the economics of the retirement versus continued operation of each existing coal unit that each company is not currently planning to retire, and to present the results of this analysis in the 2013 IRPs.

4. Direct DEC and PEC to evaluate future investments in renewable energy resources beyond the minimum REPS requirements in comparison to "conventional" resource options and analyze the potential ancillary benefits or costs of integrating significant levels of on-system renewable energy resources.

5. Direct DEC and PEC to conduct sensitivity analyses for future renewable technologies to demonstrate the maximum cost levels that would be reasonable for initial levels of resource development and identify any cost-effective technologies.

6. Direct DEC and PEC to conduct a more complete evaluation of the risks of construction delays and cost increases associated with new nuclear generation, using robust assumptions.

7. Direct DEC and PEC to provide information concerning the economic impacts of their resource planning decisions on a trial basis in the 2013 IRPs.

8. If the Commission elects not to hold an evidentiary hearing on the 2012 IRP, consider convening a workshop and/or establishing an IRP working group to provide input on the development of future IRPs.

Respectfully submitted this 5th day of February, 2013.

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CERTIFICATE OF SERVICE

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

This 5th day of February, 2013.

Robin G. Dunn

Robin G. Dunn

Figure A-1: Cost Comparison of DEC's Base, High EE/DSM, and CES (Renewable) Capital Expansion Plans

Year	Base CapEx Plans			High EE/DSM CapEx Plans			CES CapEx Plans		
	Gas	Nuclear	Regional Nuclear	Gas	Nuclear	Regional Nuclear	Gas	Nuclear	Regional Nuclear
2012-15									
2016	CC	CC	CC	CC	CC	CC	CC	CC	CC
2017			N			N			N
2018	CC	CC	N, CC			N	CC	CC	N, CC
2019	CT	CT		CC	CT	CT	CT	CT	
2020			CT						CT
2021				CT					
2022	CC	N	N		N	N	CC	N	N
2023									
2024	CC	N	N		N	N	CC	N	N
2025				CC					
2026									
2027	CC		CC	CC			CC		CC
2028	CT	CC	N			N	CT	CC	N
2029									
2030		CT	CT	CC	CT	CT		CT	CT
2031	CC						CC		
2032	CT	CT	CT	CT	CT	CT	CT	CT	CT
CT	1,930 MW	1,800 MW	1,800 MW	1,250 MW	1,820 MW	1,820 MW	1,930 MW	1,800 MW	1,800 MW
CC	4,200 MW	2,100 MW	2,100 MW	3,500 MW	700 MW	700 MW	4,200 MW	2,100 MW	2,100 MW
Nuclear	-	2,234 MW	2,234 MW	-	2,234 MW	2,234 MW	-	2,234 MW	2,234 MW
Renewable	758 MW	758 MW	758 MW	758 MW	758 MW	758 MW	*	*	*
EE/DSM	2,445 MW	2,445 MW	2,445 MW	3,643 MW	3,643 MW	3,643 MW	2,445 MW	2,445 MW	2,445 MW
Portfolio NPV Costs ($billion)									
Production	109.1	99.2	99.6	102.9	93.8	94.1	109.5	97.2	97.7
Efficiency	1.9	1.9	1.9	4.3	4.3	4.3	1.9	1.9	1.9
Capital	6.2	16.1	15.6	4.8	14.5	14.0	6.2	16.1	15.6
Total	**$ 117.3**	**$ 117.3**	**$ 117.1**	**$ 112.0**	**$ 112.6**	**$ 112.4**	**$ 117.7**	**$ 115.2**	**$ 115.2**
NPV Cost Difference ($billion) (higher values in parentheses represent greater cost savings relative to the "Optimal Plan")									
Total	$ 0.0	-	$ 0.1	$ 5.3	$ 4.7	$ 4.9	($ 0.4)	$ 2.1	$ 2.1
Average	**-**			**$ 4.9 billion savings**			**$ 1.2 billion savings**		

* Model documentation appeared to be inadequate to verify the renewable energy capacity used in the CES sensitivity analyses.

Figure A-2: Cost Comparison of PEC's IRP Capital Expansion Plans (Current Trends Scenario)

Year	Preferred Plan (Plan A)	Plan B	Plan C	Plan D	Aspirational
Baseload Strategy Description	Nuclear	Gas (Combined Cycle)	Coal	Nuclear, with Gas Reducing Coal Operation	Energy Efficiency Reducing Gas Capacity
2013	Wayne CC	Wayne CC	Wayne CC	Wayne CC	Wayne CC
2014	Sutton CC	Sutton CC	Sutton CC	Sutton CC	Sutton CC
2015					
2016	CT	CT	CT	CT	CT
2017	N		N	N	N
2018	CT	CT	CT	CC	
2019	N, CT	CT	N, CT	N	N, CT
2020	CC	CT	CT		CC
2021	N	CC	N, CT	N, CC	N
2022	CC	CC	CT		
2023	N		N	N	N
2024			CT		
2025				CC	
2026	CT	CC	CT		CT
2027	CT		CT		CT
2028	CT		CC		CT
2029	CC			CT	CT
2030	CC	CC	CC	CC	CC
2031			CT		
CT	1,665 MW	1,665 MW	3,145 MW	740 MW	1,665 MW
CC	4,693 MW	5,086 MW	3,119 MW	5,479 MW	3,905 MW
Nuclear	552 MW	-	552 MW	552 MW	552 MW
Renewable	(36) MW	(36) MW	(36) MW	(36) MW	(36) MW
EE/DSM	416 MW	416 MW	416 MW	416 MW	991 MW
Portfolio NPV Costs ($billion)					
Undifferentiated*	48.0	48.7	48.9	48.0	44.6
Production	34.6	35.8	35.4	34.4	32.8
Efficiency	0.8	0.8	0.8	0.8	2.2
Capital	4.1	2.2	3.7	4.6	3.7
Total	**$ 87.5**	**$ 87.6**	**$ 88.7**	**$ 87.8**	**$ 83.2**
NPV Cost Difference ($billion) (higher values in parentheses represent greater cost savings relative to the Preferred Plan)					
Total	-	$ 0.1	$ 1.2	$ 0.2	($ 4.3)

* Model results do not differentiate costs beyond 2031.