STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 141

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2014 Biennial Integrated Resource Plans and Related 2014 REPS Compliance Plans	))))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Monday, March 9, 2015, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

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For the Using and Consuming Public:

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BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs” for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills . . . .

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] EE measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),[3] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

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[1] G.S. 62-133.9(c).

[2] G.S. 62-133.8(a)(2) and (4).

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2014 BIENNEIAL REPORTS

This Order addresses the 2014 biennial reports (2014 IRPs) filed in Docket No. E-100, Sub 141, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Electric Membership Corporation (NCEMC); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff’s intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 29, 2014, DNCP filed its 2014 biennial IRP report and REPS compliance plan. On September 2, 2014, DEC and DEP filed their 2014 biennial IRP reports and REPS compliance plans.

On September 29, 2014, the Commission issued an Order Establishing Dates for Comments on Integrated Resource Plans and REPS Compliance Plans. That Order set January 30, 2015, as the date for filing petitions to intervene and for filing initial comments. Reply comments were due on February 13, 2015.

On January 20, 2015, the Commission issued an Order Scheduling Public Hearing on 2014 Biennial IRP Reports And Related 2014 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on March 9, 2015, in Raleigh.

On January 21, 2015, DEP filed a corrected page 174 to its IRP report due to errors discovered in the calculation of the projected cost amounts contained in Table 5.

On January 28, 2015, the Public Staff filed a motion for extension of time for the filing for petitions to intervene and initial comments to February 23, 2015, and the date for reply comments to March 12, 2015. The Commission granted this motion on January 29, 2015.

On February 20, 2015, the Public Staff filed a second motion for extension of time for the filing for petitions to intervene and initial comments to March 2, 2015 and the date for reply comments to March 19, 2015. This motion was granted by the Commission on the same day.

Also on February 20, 2015, NC WARN filed its initial comments and a request for an evidentiary hearing.

On February 27, 2015, initial comments were filed by MAREC.

On March 2, 2015, initial comments were filed by NCSEA, the Public Staff and jointly by SACE and the Sierra Club.

On March 9, 2015, the public witness hearing was held in Raleigh, as scheduled.

On March 10, 2015, DEC, DEP and DNCP filed a joint motion for extension of time to file reply comments to April 9, 2015. This motion was granted on March 11, 2015.

On March 20, 2015, NC WARN filed a correction to paragraph 45 on page 27 of its initial comments filed on February 20, 2015.

On April 7, 2015, DEC, DEP and DNCP filed a joint motion for a second extension of time to file reply comments to April 20, 2015. This motion was granted by the Commission on April 8, 2015.

On April 20, 2015, reply comments were filed by DNCP, and jointly by DEC and DEP.

Public Hearing

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, March 9, 2015, at 7:00 p.m., where 13 public witnesses spoke. The witnesses discussed the damage that fossil fuels do to the environment versus the benefits of generating electricity with renewable sources of energy, especially solar. It was noted that we are all stewards of the planet with a responsibility for building a healthy place for people and wildlife to flourish together.

The witnesses offered support for the EPA Clean Power Plan and an overall increase in the use of renewables and energy efficiency programs, including offering incentives to electricity consumers to invest in energy efficiency measures. There was also discussion of various issues related to coal ash cleanup.

Request for Evidentiary Hearing

In NC WARN's comments and request for an evidentiary hearing, filed on February 20, 2015, NC WARN first discusses the purpose of the IRPs and NC WARN's overriding criticism that DEC's and DEP's (collectively, Duke's) IRPs maintain the status quo of heavy reliance on fossil fuel generation. In summary, NC WARN makes four main points: (1) that Duke's growth forecasts are unrealistic; (2) that Duke's IRPs include its continued reliance on expensive and unnecessary new natural gas and nuclear plants; (3) that Duke fails to plan to use strategic purchases and transmission cooperation with other utilities and merchant plants even though Duke and other southeastern electricity providers have significant excess capacity; and (4) that Duke fails to plan for the use of cost-effective and readily available renewable energy, energy efficiency measures, and combined heat and power (CHP) resources.

NC WARN's Comments

NC WARN asserts that both DEC and DEP base their 15-year IRPs on a 1.4% annual growth in peak demand for electricity, even though actual growth in electricity demand has been flat for more than a decade. NC WARN further notes that these projections include the impact of Duke's energy efficiency programs, and estimates that the actual growth in demand projected by Duke is almost 1.9%. NC WARN submits that these projections are unrealistic because they are based on a full economic recovery and a booming growth in population. In contrast, NC WARN forecasts zero growth, which it submits is in line with the most recent growth projections by the United States Energy Information Administration (EIA), and the American Council for an Energy-Efficient Economy (ACEEE), as well as actual growth for the past decade. NC WARN states that projected demand growth is a crucial component in determining the costs for new generation facilities and that the Duke forecast, resulting in a need for 7,282 MW of capacity, will cost ratepayers over $25 billion, potentially doubling electric rates over the IRP planning period. On the other hand, NC WARN's analysis shows that a zero growth scenario allows for the phase out of all coal plants, eliminates the need to construct new nuclear plants and reduces the need for some existing natural gas generation. According to NC WARN, this can be achieved with strengthened energy efficiency measures, a more rapid development of renewable energy, continued reliance on pumped storage, and the fostering of distributed generation, backed up with purchases from other utilities and merchant plants.

In addition, NC WARN notes that Duke's reserve margins over the IRP planning period are in excess of Duke's goal of 14.5%, with DEC's reserve margins ranging from 15% to 22.7% for summer peak (and 19.4% to 25.7% for winter peak), and DEP's ranging from 15.2% to 21.1% for summer peak (and 22.1 to 31.7% for winter peak). NC WARN opines that all utilities in the southeast region have excess capacity that should be used among the utilities to supplement each other's generation requirements, rather than building unneeded or underutilized generation. NC WARN cites and discusses the North American Electric Reliability Corporation's (NERC's) 2014 Summer Reliability Assessment. NC WARN contends that there are no compelling reasons why Duke and the other southeast utilities should continue to construct new generation without looking at mutual purchasing agreements. According to NC WARN, using average monthly peaks taken from EIA Form-714 for the shoulder months of April, May, October and November, DEC's average reserve capacity during its monthly peak is 40.6%, while DEP's is 36% and for several of these shoulder months, more than 50% of the available capacity was not needed. In addition, the excess capacity would be even more extreme assuming a flat growth rate. NC WARN discusses studies by FERC and the Lawrence Berkeley National Laboratory, and suggests that North Carolina could optimize energy efficiency and reliable distribution by implementation of a regional transmission organization (RTO), or other similar regional strategy.

NC WARN also discusses Duke's plan to build new nuclear plants. It asserts that these projects will be extremely expensive and risky, citing the cost of projects in other states. Further, NC WARN laments the drawbacks of Duke's increased reliance on natural gas plants as a baseload resource, including greenhouse gases and externalized costs of fracking and conventional drilling, refining, transportation and combustion. Further, NC WARN submits that the utilities should include an assessment of the amount of carbon emissions and other pollution as a part of their IRPs, asserting that the externalized costs from fossil fuels, such as the estimated 17 - 27 cents/kWh in health and environmental damages from coal-fired electricity, add tremendously to the cost of generating electricity with fossil fuels. NC WARN states that Duke is expected to emit approximately 34.5 million tons of carbon dioxide annually, and that the coal plants being closed by Duke are old, small coal units rarely used in the years preceding their scheduled closures, noting that the average capacity of the units that Duke has closed or projects to close is 110 MW and the age of the units at the time of retirement ranges from 50 to 89 years.

NC WARN contends that its plan for North Carolina's energy future is competition driven, its primary goal being to maximize efficiencies and thus minimize costs to ratepayers. To do this, NC WARN would increase energy efficiency and renewable energy, and encourage distributed generation to place energy sources near where they are needed. According to NC WARN, this would allow for closure of all coal-fired power plants, eliminate the need for new centralized generating plants and, as a result, decrease electric rates and pollution. NC WARN's Appendix A contains a set of pie charts comparing Duke's forecasts with those in NC WARN's energy proposal -- a zero growth scenario. NC WARN states that the most significant difference between NC WARN's plan and Duke's is NC WARN's proposed increase of energy efficiency and demand-side management (DSM) programs to 19% of capacity and 24% of energy over the planning horizon, far greater than the 5% of capacity and 5.1% of energy in Duke's IRPs. Likewise, CHP and microgrids are increased to 8% of capacity and 10% of energy in the NC WARN plan, while neither is included in Duke's forecasts. Similarly, wind and solar is increased to 18% of capacity and 7% of energy in the NC WARN proposal, far greater than the 4% of capacity and 4% of energy in Duke's plan. Wholesale purchases in the NC WARN plan are 6% capacity and 6% in sales compared to 0.8% capacity and 0.2% in Duke's plan.

Moreover, NC WARN submits that some utility companies, including Florida Power and Light (FPL), argue that energy efficiency has run its course and is no longer the best option. Nevertheless, NC WARN states that a recent report by ACEEE shows that utility energy efficiency programs appear to be holding steady as the least-cost resource. Similarly, in recent long-term predictions the EIA addresses the implications of low electricity demand growth and examines various scenarios to show the effects of future savings. The EIA low electricity demand growth report discusses how variations in the amount of energy efficiency done now can affect the demand in the coming years. In the reference case, which assumes no new efficiency standards beyond those already in place, total electricity use grows by an average of less than 1% per year from 2012-2040. In addition, NC WARN discusses the energy efficiency gains made in lighting, commercial air conditioners, refrigeration units and “smart appliances.”

NC WARN further states that ACEEE’s 2014 State Energy Efficiency Scorecard ranks North Carolina number 24 among the states, with no change from the previous year. NC WARN contends that North Carolina’s utilities should take more initiative to implement energy efficiency programs, as efficiency continues to be the most cost effective option available.

In addition, NC WARN submits that the second main component of a responsible energy future is a renewable energy build-up to account for 7% of total electricity sales and 18% of total capacity in North Carolina over the planning horizon, including both retail and wholesale sales. Within this expansion, NC WARN sees solar photovoltaic (PV) systems as a tremendous resource that can provide reliable electricity, with costs continuing to fall steadily. It discusses several initiatives that are contributing to the growth of solar resources in North Carolina, and studies showing that solar has reached grid parity in ten states, and would reach grid parity in 36 of 50 states by 2016. NC WARN further contends that solar facilities are a positive asset to utility grids, providing resilience, diversity, and a hedge against increased fuel costs. In addition, NC WARN states that further development of storage technology is poised to bolster the rapid growth of distributed renewable energy such as wind and solar and provide additional grid support.

NC WARN states that it also continues to recommend the development of substantial CHP systems for commercial and industrial customers who use both heat and electricity in their facilities, and microgrid technologies putting electricity generation as close as possible to where it is needed. It states that conventional methods of producing heat and power separately have a typical combined efficiency of 45%, while CHP systems often have a total efficiency of 70 – 80%, and are versatile and flexible. Noting that currently in North Carolina there are 167 CHP facilities in operation, with a capacity of 1,541 MW, NC WARN notes that in the United States CHP represents nearly 10% of total generating capacity.

NC WARN submits that at a minimum Duke's business model will in all likelihood cause rates to double from 2009 to 2029, with additional increases in the subsequent decade depending on when new large-scale generation is added. In contrast, NC WARN asserts that its approach can provide billions of dollars in annual savings for North Carolina electricity customers, and is a responsible energy future, one that promotes job creation, a good economy, and a healthier place to live, while also doing North Carolina's share in finding solutions to climate change.

NC WARN concludes its comments with a request for an evidentiary hearing on (1) Duke's 1.5% growth rate forecast; (2) Duke's continued reliance on new natural gas and nuclear plants; (3) Duke's refusal to plan on strategic purchases and transmission cooperation with other utilities and merchant plants; and (4) Duke's failure to plan for cost-effective and readily available renewable energy, energy efficiency measures, and CHP.

Duke's Reply Comments

In its reply comments, Duke states that NC WARN essentially restated the same arguments that NC WARN made in the 2013 IRP docket and notes that those arguments were rejected by the Commission. In summary, Duke asserts that NC WARN advances unsupported positions regarding the resource plans filed by DEC and DEP. In particular, Duke asserts that NC WARN's proposed alternative resource plan is not supported by legitimate data or substantive analysis. Duke states that when it sought information from NC WARN it was informed that NC WARN did not prepare a true load forecast, but simply assumed “zero growth.” Duke states that such an assumption is entirely inconsistent with the actual data utilized to prepare the load forecasts for Duke's 2014 IRPs, and that Duke stands by the reasonableness of the load forecasts contained in its 2014 IRPs. Duke also notes that its load forecasts are supported by the Public Staff.

With regard to NC WARN's comments on Duke's proposed coal retirement and replacement plan, Duke states that NC WARN's responses to data requests indicated that NC WARN did not prepare production cost simulation models and screening models of its plan or model, nor develop any of the inputs listed in the data request, except the cost of coal and natural gas price forecasts. In addition, Duke states that according to NC WARN’s data request responses, the pie charts contained in Appendix A to NC WARN’s report were prepared by NC WARN’s researcher/paralegal. Further, in response to a data request seeking the detailed data assumptions utilized to determine the economic value of the analysis reflected in NC WARN's comments, NC WARN responded, “NC WARN has not conducted PVRR calculations, nor made assumptions associated with those calculations.” (NC WARN Response to Duke Energy’s First Data Request No. 21, March 18, 2015)

Moreover, Duke notes that NC WARN also alleges that, “If the Commission approves the Duke Energy plan, it approves a status quo threatening to bankrupt North Carolina’s economy” (NC WARN Comments, at p. 3). However, Duke states that in response to a data request asking for all workpapers, studies or other documents that were relied upon in forming this statement, NC WARN responded that it did not have any such workpapers or studies, but that its statement is explained in its comments, and based on 0% load growth and the potential that Duke's rate will double in order to pay for new generating plants. Duke maintains that NC WARN has no credible support for its allegation that Commission approval of Duke's 2014 IRP would threaten to bankrupt North Carolina’s economy.

With regard to NC WARN's assertion that Duke can retire all existing coal units and some existing natural gas units, and meet its customers' needs exclusively through a mix of new EE, renewable energy, pumped storage, distributed generation, and purchases from other utilities and merchant plants, Duke states that NC WARN has no legitimate economic analysis to support its proposed resource plan. As an example, Duke cites NC WARN's response to a data request in which NC WARN acknowledges that it has not documented the capital costs, on-going capital streams, fixed and variable O&M costs, life of asset, assumptions of federal/state tax incentives, load profiles, and capacity factors beyond the statements and footnotes in the comments. Further, in response to a data request seeking the EE and demand response costs, program participation and participation studies used to support the NC WARN comments, NC WARN stated that it had not prepared that data beyond NC WARN's proposal for a Community Enhanced Income Qualified Energy Efficiency and Weatherization Program, as contained in NC WARN's testimony in Docket No. E-7, Sub 1032. Duke also states that NC WARN has conducted no revenue requirements analysis for its proposed resource portfolio and, therefore, has no legitimate basis to assert that its proposal will be cost effective for Duke's customers. In addition, Duke states that WARN's alternative resource plan was apparently developed without regard to system reliability concerns. In support of this observation, Duke notes that NC WARN's data request responses reveal that it conducted no loss of load study. Further, when asked to explain in detail how its proposed plan will provide adequate reliability for Duke's customers, NC WARN responded simply as follows:

> As stated in the Comments, paragraph 6 and accompanying footnotes, the inclusion of a balanced mix of distributed generation and energy efficiency is more reliable than the current generation – transmission – distribution system, and especially if backed up by batteries. Electricity is placed where it is most needed both on the grid and at peak periods, and at the same time, distributed generation provides grid support services. As noted in the Comments, paragraphs 15-16, a wide variety of these sources do not require as high a reserve margin as does a system relying on a limited number of large coal and nuclear plants. In addition, NC WARN recently looked at the value of solar, including reliability, as part of the preparation of [testimony filed by NC WARN in Docket No. E-100, Sub 140].

NC WARN Response to Duke Energy's First Data Request No. 11, March 18, 2015.

Duke asserts that NC WARN's responses to its data requests create significant concern with the analysis presented by NC WARN that serves as the basis for NC WARN's comments.

With respect to NC WARN's contention that Duke's reserve margins are "consistently above average for the industry" and that Duke and "all of the utilities in the Southeast region have excess capacity," Duke notes that in the last two winters frigid temperatures pushed utility systems throughout the country to their limits. Duke states that its ability to serve its retail customers under these challenging conditions proves that NC WARN's position is wrong and misguided. According to Duke, if it had not been able to access its full portfolio of resources at the current planning reserve margins, the outcome easily could have been rolling blackouts or much higher electricity prices. In addition, NC WARN’s assertion that Duke could simply rely on excess capacity throughout the region also was proven to be incorrect during this period, as Duke's neighboring utilities confronted the same frigid temperatures and peak demands, and had little or no capacity to share with other utilities.

In conclusion, Duke submits that NC WARN's alternative resource plan would not enable North Carolina to ensure that reliable and affordable electricity is available to all customers over the IRP planning horizon. Duke acknowledges that renewable resources, EE and DSM are important and increasingly significant components of its IRPs, but states that they cannot realistically be relied upon in the almost exclusive nature that NC WARN has proposed. In contrast, Duke maintains that its IRPs present robust and balanced portfolios of diverse supply and demand side resources that will cost-effectively and reliably serve customers’ needs across a range of many possible future scenarios. Accordingly, Duke requests that NC WARN's comments be disregarded and its request for an evidentiary hearing be denied.

DNCP's Reply Comments

In its reply comments, DNCP notes that NC WARN's concerns are not focused on DNCP's 2014 IRP. In addition, DNCP opines that NC WARN has not presented any compelling issues or reasoning in support of its request for an evidentiary hearing. Finally, DNCP states that if a hearing is held it should be limited to issues regarding Duke's 2014 IRPs.

Discussion

General Statute 62-110.1(c), in pertinent part, requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity.” In State ex rel. Utils. Comm’n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that

> [t]he Duke and CP&L plans were “reasonable for the purposes of [the] proceeding” before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of “analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…” See N.C. Gen. Stat. § 62-110.1(c).

The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing “directives which fundamentally alter a given utility's operations.” With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

In the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the underlying data, modeling and analyses presented by the utilities, the Public Staff and the intervenors. With respect to the credibility of Duke's load forecasts, as more fully discussed later in this Order, the Public Staff reviewed Duke's load forecasts and concluded that Duke employed accepted statistical and econometric forecasting practices. Therefore, the Public Staff supports the reasonableness of Duke's load forecasts for planning purposes. Comments of the Public Staff, at 12-18.

Likewise, the Public Staff reviewed Duke's reserve margins and found them to be reasonable for planning purposes. The Public Staff describes the Loss of Load Expectation (LOLE) probabilistic assessment employed by Duke in estimating its reserve margins. The Public Staff also discusses the tight reserve margins experienced by Duke during the unusually cold temperatures in 2014 and 2015, and notes that neighboring utilities were experiencing the same tight supplies. Comments of the Public Staff, at 37-41.

In contrast, it does not appear that NC WARN employed specific data or modeling techniques to support its load forecast of 0% growth and its criticisms of Duke's reserve margins. The Commission appreciates and is interested in the statistics and analyses of EIA, NERC ACEEE and other national organizations. On the other hand, the Commission's charge in this proceeding is to determine whether the utilities' IRPs are reasonable planning tools for North Carolina's electric needs. Regional and national forecasts simply do not carry the weight of the specific, data-based analyses employed by Duke and verified by the Public Staff.

Similarly, in the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the goal of adequate and reliable electric service. Planning for adequacy and reliability requires careful analysis that gives due consideration to a myriad of factors, not just cost. NC WARN's proposals rely heavily on renewable resources and energy efficiency programs. However, it does not appear that NC WARN has given due consideration to factors such as load profiles, the future of tax incentives for renewable resources, capacity factors of renewable resources, transmission availability and energy efficiency program participation rates. On the other hand, the Public Staff discusses its review of Duke's extensive resource modeling techniques, including Duke's use of the System Optimizer and Planning and Risks models, and finds Duke's analyses to be reasonable for planning purposes.

Comments of the Public Staff, at 46-59. In addition, the Commission notes that in a CPCN proceeding for an electric generating plant G.S. 62-110.1(d) requires the Commission to consider the applicant's arrangements for purchased power, power pooling and other such interchanges. Further, in CPCN proceedings for coal or nuclear plants G.S. 62-110.1(e) requires the applicant to demonstrate that energy efficiency measures, DSM, renewable resources and CHP, or any combination thereof, would not be as reliable or cost-effective as the proposed generating plant. Therefore, NC WARN's proposals can be addressed directly and appropriately at the time that Duke applies for a CPCN to build additional generating facilities in North Carolina.

Pursuant to Commission Rule R8-60(j), an intervenor may file an IRP of its own with respect to any utility. If it chooses to propose an alternative IRP, the intervenor's IRP should conform to the information and analytic requirements of Rule R8-60(c) – (i). To the extent that NC WARN intended for its comments to be construed as an alternative IRP for Duke, the Commission finds and concludes that NC WARN's proposal was inadequate with respect to data, modeling and analysis.

On March 9, 2015, the Commission held a public hearing in Raleigh for the purpose of receiving testimony from Duke's and DNCP's ratepayers. Thirteen witnesses testified regarding their views and concerns on a wide range of topics, including renewable energy, energy efficiency, coal ash disposal, coal plant retirements and CHP. The Commission has fully considered the testimony of these public witnesses, along with numerous statements of position from ratepayers on these and other matters, in arriving at its conclusions in this Order. This information, plus the IRPs and the parties' comments and reply comments, provide the Commission with an extensive record in this docket. Having reviewed the record and considered the parties' arguments, the Commission concludes that the issues raised by ratepayers at the hearing and in their statements of position, as well as those raised by NC WARN in its comments and request for an evidentiary hearing, have been adequately addressed by Duke.

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing. As a result, the Commission is not persuaded that there is good cause to grant NC WARN's motion that the Commission hold an evidentiary hearing in this docket. Therefore, the motion should be and is denied.

FINDINGS OF FACT

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following findings of fact:

1. The IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and should be approved.

2. The IOUs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

3. The Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

4. DEP, DEC and DNCP have adequately addressed the Public Staff's specific recommendations regarding the 2014 IRPs.

5. The IOUs included a full discussion of REPS compliance and their plans should be approved.

6. DEP, DEC and DNCP have adequately addressed the issues raised by the intervenors.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2015–29) of DEP, DEC, and DNCP. The compound annual growth rates (CAGR) for the forecasts are within the range of 1.0% to 1.4%.

All of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. As with any forecasting methodology that uses computer modeling, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2013 IRPs. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2009 IRPs by comparing them to their actual peak demands and energy sales. A review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, the Public Staff reviewed the forecasts of other adjoining utilities and the SERC Reliability Corporation.

In their 2013 IRPs, all three utilities predicted that their 2014 system peaks would occur in the summer. However, during January 2014, the IOUs reported several hourly peak loads that were greater than the summer peak loads that occurred later that year. Additionally, in February 2015, both DEC and DEP experienced all time system peaks.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.3%, as compared to growth rates of 1.2% and 0.9% in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its energy efficiency (EE) programs, DEP would expect its summer peaks to grow at a rate of 1.6%. The average annual growth of its summer peak, which DEP considers its system peak, is forecasted to be 190 megawatts (MW) for the next 15 years according to the 2014 IRP, in comparison to a predicted growth of 171 MW in DEP's 2013 IRP. DEP predicts that in 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 4%, which is similar to its projection in its 2013 IRP. DEP assumes that it can actively reduce 7% of its peak load by using its demand-side management (DSM) resources, which it considers a capacity resource.

The Public Staff observed that DEP's forecast of its winter peak loads reflects a slightly lower CAGR of 1.2% than that of its summer peaks, with winter peaks approximately 600 MW less than the forecasted summer peaks on average. DEP's energy sales, including the impacts of its EE programs, are predicted to grow at a CAGR of 1.0%, as compared to 1.4% and 1.0% in its 2013 and 2012 IRPs, respectively. DEP predicts that over the next 15 years, the megawatt-hour (MWh) reductions from its EE programs will cause a reduction in annual energy sales of 1% in 2015, increasing to approximately 4% in 2029. This is similar to the projection in DEP's 2013 IRP.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in DEP's 2013 IRP overpredicted the 2014 summer peak load by 12% and underpredicted the 2014 winter peak forecast by 12%. However, the forecast errors are reduced to 5% and below when the two peaks are adjusted to remove the impacts of an unusually mild summer peak-day temperature and an abnormally cold peak-day winter temperature.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEP's peak and energy forecasts are reasonable and that DEP has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff asserted that DEP's peak load and energy sales forecasts are reasonable for planning purposes.

DEC

Regarding DEC, the Public Staff responded that DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.4%, identical to the 1.4% forecast in its 2013 IRP and similar to the 1.7% growth rate projected in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC would expect its summer peaks to grow at an average of 1.7% each year for the next 15 years. The average annual growth of its summer peak, which DEC considers its system peak, is forecasted to be 286 MW for the next 15 years, as opposed to the 283 MW and 321 MW forecast in its 2013 and 2012 IRPs, respectively. DEC predicts that in the next 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 5%, similar to its projection in its 2013 IRP. The plan also assumes that the Company can reduce 5% of its load by 2029 by using its DSM resources, considered a capacity resource. DEC's forecast of its winter peak loads reflects a slightly higher CAGR of 1.5%; however, on average, the winter peaks are approximately 1,180 MW lower than the forecasted summer peaks.

The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.0%. This growth rate is less than the 1.5% and 1.7% predicted in its 2013 and 2012 IRPs, respectively. DEC predicts that its EE programs will reduce its energy sales by approximately 6% by 2029.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in its 2013 IRP overpredicted its summer peak load by 9% and underpredicted its 2014 winter peak load by 8%. However, the forecast errors are reduced to 3% and below if the two peaks are adjusted to remove an unusually mild summer peak-day temperature and an abnormally cold winter peak-day temperature.

The Public Staff pointed out that, for several years, DEC's forecasts for both peak demand and energy sales have consistently been higher than the actual peak demands and sales. In contrast, DEP's and DNCP's forecasts generally have generated at least one annual peak prediction that was less than the actual peak. The five-year trend of overpredicting DEC's loads is still apparent even when the abnormally high winter peak load in 2014 is used instead of the summer peak load of 2014. Using this calculation, DEC's peak load was overpredicted by an annual average of 435 MW.

According to the Public Staff, the importance of load forecast accuracy cannot be overstated given that the resource expansion plan is designed to serve the forecasted load at the least cost. The adoption of a forecast with a lower growth rate of 1.0%, as opposed to DEC's forecasted 1.4%, would result in the elimination of the need for at least one or more of the planned large baseload units, while maintaining a reasonable reserve margin over the 15-year plan. A 1% growth rate is hypothetical; however, this lower growth rate, in comparison with DEC's estimate of 1.4%, is closer to DEC's recent peak demand growth rate.

Nonetheless, the Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's peak and energy forecasts are reasonable and that DEC has employed accepted statistical and econometric forecasting practices. The Public Staff continues to be concerned with DEC's pattern of overforecasting more often than underforecasting its load. As noted in the Public Staff's comments on the 2013 IRPs, after the merger of DEP and DEC, DEP adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and peak demands before the merger had been more accurate than DEC's forecasting. Before the merger, DEP typically relied on a monthly-based econometric model with end-use data over a span of ten or more years of historical data for its energy sales forecasts. This model was used for over 30 years, and during these years, DEP used the load factor method to forecast its peak demands. DEC has also used econometric models. It has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years, but is now planning to replace its current model with a monthly peak model. While DEC's 2014 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements.

DNCP

The Public Staff observed that DNCP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.0%, a decrease from the 1.2% and 1.5% growth rates projected in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP would expect its summer peaks to grow at 1.4%. The average annual growth of its summer peak is forecasted to be 198 MW for the next 15 years, in comparison to the 239 MW forecast in the 2013 IRP. DNCP predicts that in the next 15 years, the load reductions from its EE programs will reduce its annual peak load by approximately 2%, an increase from the 1% forecast in its 2013 IRP. DNCP predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 1% by 2029. While DNCP's forecast of its winter peak loads reflects a slightly higher CAGR of 1.1% relative to the 1.0% CAGR for its summer peaks, the winter peaks are approximately 3,382 MW less than the forecasted summer peaks on average.

The Public Staff indicated that DNCP's energy sales are predicted to grow at an average annual rate of 1.1%, a decrease from the 1.4% and 1.6% growth rates predicted in its 2013 and 2012 IRPs, respectively. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% by 2029.

The Public Staff's review of DNCP's actual peak load forecasting accuracy for one year shows that its 2013 IRP overpredicted the Company's summer peak load by 6% and underpredicted its 2014 winter peak load by 11%. As with DEC and DEP, the forecast errors are somewhat attributable to the mild summer peak- day temperatures and abnormally cold peak-day winter temperatures for 2014.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DNCP's peak and energy forecasts are reasonable and that DNCP has employed accepted statistical and econometric forecasting practices; therefore, the Public Staff concludes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

PUBLIC STAFF'S CONCLUSIONS ON PEAK LOAD FORECASTS

The five-year forecast errors based on the summer peak forecasts filed in the 2009 IRP have improved from those calculated based on the 2008 IRPs, especially for DEC. Nevertheless, the Public Staff remains concerned with DEC's tendency to overforecast its summer peaks. However, the Public Staff believes that DEC's move to a monthly model may correct this tendency.

A second concern involves the unexpectedly large increases in the demand for electricity at the 2014 system peaks for all three IOUs that occurred in January at abnormally low temperatures. Identifying and properly forecasting the shape of customers' response to abnormally cold conditions can be challenging due to its non-linear nature that may not be fully captured in the current equations in the IOUs' peak forecast models. As such, the Public Staff recommends that the companies review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.

SUMMARY OF GROWTH RATES

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts based on their IRP filings.

2015- 29 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.3%	1.2%	1.0%	190
DEC	1.4%	1.5%	1.0%	286
DNCP	1.0%	1.1%	1.1%	198

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2014 annual system peak of 14,159 MW occurred on January 7, 2014, at the hour ending 8:00 a.m., at a system-wide temperature of 11 degrees. The 11 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. DEP's 2013 and 2012 peaks were 12,166 MW in August 2013 and 12,770 MW in July 2012. The 2014 peak occurred after several days of abnormally cold temperatures. The Company projected its day-ahead operating reserves at 5.8%. In addition to the abnormal temperatures, several of the Company's generating units were down with forced outages, resulting in available operating reserves of only 0.19% at the time of its actual peak. Due to its low operating reserves, DEP activated all of its DSM resources and reduced its peak demand by 383 MW as follows: EnergyWise Home for 9 MW, Commercial, Industrial, and Government (CIG) Demand Response Automation for 6 MW, Distribution Service Demand Response (DSDR)[4] for 157 MW, and Curtailable Rate programs for 211 MW.

[4] The Commission has classified DSDR as an EE program, but DEP generally uses it as it would a DSM program.

DEC's system peaked at 19,151 MW on January 30, 2014, at the hour ending 8:00 a.m. at a system-wide temperature of 12 degrees. The 12 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. Given the forecasted weather conditions and unit availability, DEC had anticipated that its day-ahead operating reserves would be approximately 18%. However, at the actual time of system peak, its operating reserves fell to 2.4%. At this time, the Company did not activate any of its DSM programs. However, during its second highest peak, which occurred on January 7, 2014, the Company did activate its DSM programs, reducing load by 478 MW. At hour ending 8:00 a.m. that day, DEC anticipated having 10% available operating reserve; however, its actual level of operating reserves fell to 0.24%, similar to DEP's 0.19% operating reserves. The Public Staff notes that the extended unusually cold temperatures resulted in higher than projected energy use and that coincident forced outages (also related to the extended abnormally cold temperatures) also contributed to the low reserves available for both DEC and DEP. During the morning hours on January 7, DEC activated its Interruptible Service for 124 MW, Standby Generation Service for 31 MW, PowerShare Mandatory for 310 MW, and Power Share Generators for 13 MW. On the next day, DEC activated the same four programs with similar load reductions. In regard to DSM activations during the Company's highest 15 peak loads, DEC used DSM on three occasions, with its third and final DSM activation on September 2, 2014, obtaining a 202 MW load reduction from its PowerShare Mandatory program. DEC's 2013 IRP projected 561 MW of available DSM capacity, while in actuality only 478 MW, or 85%, of the 2013 projection was available.

DEC has indicated to the Public Staff that its DSM resources are used in near emergency situations to maintain reliability and has pointed to its higher level of available operating reserves at the time of the peak and other near peak events that forestalled the need to use DSM. DEC also stressed two additional important considerations with regard to DSM activations. First, each DSM program has different timing considerations regarding advance notice to participating customers and customer response times that may affect the ability of the utility to call on a particular customer. Second, over-utilization of DSM programs could reduce the willingness of customers to participate in the programs, negatively impacting the long-term availability of those programs for reliability purposes.

The Public Staff recognizes these important considerations and agrees the utilities must take them into account in deciding when and to what extent to activate their DSM programs. Nonetheless, the Public Staff believes that DEC could take greater advantage of its DSM programs by activating them on a more frequent basis, both for reliability and for reduction in fuel costs.

DNCP's 2014 annual system peak of 16,840 MW occurred on January 30, 2014, at the hour ending 8:00 a.m., unlike its 2013 and 2012 system peak loads of 16,366 MW and 16,787 MW, respectively, both of which occurred in the summer. At the time of the 2014 peak, DNCP called on its Distributed Generation Pilot[5] (DG) for a

[5] The Distributed Generation Pilot is approved only in Dominion's Virginia jurisdiction.

load reduction of 10 MW, which is less than the 34 MW of DSM identified as being available in DNCP's 2013 IRP.

THE PUBLIC STAFF'S COMMENTS ON DSM ACTIVATIONS

One area of concern for the Public Staff in its review of the DSM activations at the time of the 15 highest hourly peaks for each utility is the actual DSM load reductions that are realized when system operations call on DSM as a resource. There is a substantial difference between the DSM load reduction actually realized on the 15 days when peak demand was highest for all three utilities and the amount of DSM load reduction forecasted.

As noted previously, despite complete activations of its DSM programs, DEP had only 76% of its projected DSM capacity actually available at the system peak on January 7, 2014. Likewise, DEP's use of Energy Wise in the summer resulted in 107 MW of capacity reduction out of the 230 MW forecasted to be available.

During DEC's two uses of its Power Manager Program during the summer, the program produced a load reduction of 61% of the reduction forecast in the IRP for planning purposes. For DEC's Power Share-Mandatory program and Schedule SG customers, the load reduction realized from both programs was approximately 85% of the reduction forecast in the IRP. However, Schedules IS achieved a load reduction of 95% of the total reduction DEC had indicated to be available.

DNCP's DSM capacity reductions were also below the amount forecast in its IRP, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively.

A second area of concern for the Public Staff involves differences in DSM resources available in the winter as opposed to the summer because winter season DSM has typically not been found to be cost effective. Each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. However, DEP is the only utility that has any dispatchable DSM for use during the winter season (the Heat Strips and Water Heater measures in the EnergyWise program). While DSDR has been classified by the Commission as an EE program, it was used by DEP several times in both the winter and summer seasons to reduce peak demand.

The Public Staff has two recommendations to address these concerns regarding DSM. First, the DSM resources identified in the IRP should represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Through evaluation, measurement, and verification (EM&V) of these DSM programs, utilities should identify the enrolled DSM capacity and the reasonably expected level of load reduction that can be reliably called on during a DSM event, winter and summer. Second, the recent rise in winter peak demands suggests that the IOUs should pursue a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

In its comments, the Public Staff noted that DEP and DEC use a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. The reserve margins that correlate with this LOLE are approximately 14.5% for DEP and DEC. Because generating capacity is added in block amounts, DEP and DEC target as an acceptable reserve margin a range of approximately 14.5% – 17.0%. Additional analysis was performed to verify the adequacy of these target reserve margins following the implementation of the Joint Dispatch Agreement (JDA) between DEP and DEC. Based on this subsequent review, DEC and DEP utilize a 14.5% target planning reserve margin.

DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. PJM's 2013 Reserve Requirement Study recommends use of a reserve margin of 15.7% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM, and therefore its ability to meet its PJM reserve requirements. This coincidence factor reduces the Company's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin that is commensurate with the upper bound where the Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11.2%.

According to the Public Staff, for the planning period 2015 to 2029, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the planned reserves are:

Electric Utility	Planned Reserve 2015-2029	Target Reserve Margin
DEP	15.2% to 21.1%	14.5%
DEC	15.0% to 21.2%	14.5%
DNCP	11.2% to 17.4%	11.2%

The Public Staff explained that DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum

14.5% by three percent or more in 2015-17 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by three percentage points or more in 2022 and 2023 as a result of the addition of large combined-cycle (CC) facilities.

DEC's IRP indicates that its reserve margins will meet its projected reserve margin targets for the planning period and will exceed the minimum 14.5% by three percent due to a decrease in the load forecast in 2015, and in subsequent years (2020, 2021, 2024, and 2025-2028) coincident with large unit additions.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases to ensure that its reserve margins meet the target of 11.2% reserves in 2014 and thereafter.

Based on its review of the annual plans, the Public Staff believes that the reserves listed are reasonable, and recommends that DEP, DEC and DNCP maintain their proposed reserve margins as filed.

The Public Staff does note that these projected reserve margins are based on the load growth estimates and the projected peaks forecast by the Companies. Actual winter peaks for 2014 and this year have exceeded the estimates by a significant amount due, in part, to abnormally cold weather. Forced outages coincident with the winter peaks resulted in very low available reserves at the time of DEP's system peak on January 7, DEC's peak on January 30, and the most recent peak of DEC and DEP, which occurred on February 20, 2015.[6] This abnormal weather also stressed the available capacity for neighboring utilities. In particular, South Carolina Electric & Gas' shed 300 MW of its load during the polar vortex of 2014. Good system operation, firm and spot purchases, employment of DSM, appeals to the public to reduce load, and sharing of information, forecasts, and resources with neighboring utilities resulted in the utilities meeting their capacity needs to date. With two winters in a row in which the system operators have encountered some level of difficulty securing adequate winter capacity, the Public Staff recommends that DEC and DEP review their load forecasting methodology to ensure the assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather, are employed.

As such, the purpose of the Public Staff's discussion is not to examine the precise reasons for the low operating margins of DEC and DEP on January 7, 2014, but rather to highlight for the Commission how far these operating margins fell. As noted in the previous section on load forecasts, the Pubic Staff recommends that DEC and DEP work to improve their forecasting accuracy, especially with regard to possible abnormally cold weather events. DEC and DEP have indicated in discussions with the Public Staff that rather than calculating an independent winter peak forecast, as they do for

[6] Forced outages did not occur at the time of DNCP's peak on January 30, 2014, but both before and after this peak.

the summer peak, they derive the winter peak based on a ratio applied to the summer peak. The Public Staff believes that the use of a monthly peak model, as used by DNCP, may lead to better summer and winter peak forecasts. Secondly, the Public Staff recommends that DEC and DEP assess why their actual DSM capacity was significantly less than expected. Third, the Public Staff recommends that DEC and DEP continue to evaluate modifications to or maintenance of their systems to improve their operations during periods of extreme cold temperatures, so the expected capacity will be available and reserve margins maintained.

Based on its review of the annual plans, the Public Staff believes that the reserves listed are reasonable, and recommends that DEP, DEC and DNCP maintain their proposed reserve margins as filed.

DEC'S CARBON NEUTRALITY PLAN

DEC included as Appendix K to its 2014 IRP a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporated actions required under the Greenhouse Gas Reduction Plan, as well as DEC's additional obligations related to its Cliffside Unit 6 air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table K.1, (b) accommodate, to the extent practicable, the installation and operation of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018.

The Carbon Neutrality Plan submitted by DEC in its 2014 IRP is very similar to the one approved in the 2014 IRP Order, and incorporates the same implementation schedule, with updated values for the estimates of conservation, renewable energy, and nuclear uprates. The Public Staff considers this plan update to represent a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

RELICENSING OF EXISTING NUCLEAR PLANTS

As discussed in the Public Staff's comments on the 2013 IRPs, one of the significant issues faced by the IOUs is the pending expiration of operating licenses for significant nuclear energy resources in the next 20 to 30 years. The following table summarizes the current license expiration dates for the nuclear facilities owned by DEP, DEC, and DNCP.

Potential Nuclear Retirements

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DNCP	838	May 2032
Surry Unit 2	DNCP	838	January 2033
Oconee Unit 1	DEC	846	February 2033
Oconee Unit 2	DEC	846	October 2033
Oconee Unit 3	DEC	846	July 2034
Brunswick Unit 2	DEP	938	December 2034
Brunswick Unit 1	DEP	932	September 2036
North Anna Unit 1	DNCP	838	April 2038
North Anna Unit 2	DNCP	835	August 2040
McGuire Unit 1	DEC	1129	June 2041
McGuire Unit 2	DEC	1129	March 2043
Catawba Unit 1	DEC	1129	December 2043
Catawba Unit 2	DEC	1129	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff notes that recent draft revisions to technical guidance and regulation by the Nuclear Regulatory Commission (NRC) and others may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. Potential extension of licenses would be evaluated based on the specific risks and costs associated with individual units. The NRC has stated that it expects the first extensions beyond 60 years to be filed in the 2018 to 2019 time frame. Relicensing could mitigate the currently expected combined (DNCP, DEP, and DEC) loss of nuclear baseload generation of 7,013 MW in the 2030 to 2034 time frame and the loss of an additional 7,162 MW in the 2038 to 2046 time frame. The Public Staff recommended in its comments filed in response to the 2013 IRPs that in their 2014 IRPs, the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs. No scenarios were included in the 2014 IRPs that discussed this issue.

While it acknowledges the uncertainty of this potential, the Public Staff notes reports that DEC's Oconee and DNCP's Surry nuclear plants have been identified as leading candidates for license extension beyond 60 years.[7] Extensions of the licenses for the existing units would dramatically change the utilities' energy needs and therefore the forecasted construction schedule of new generation. The Public Staff repeats its recommendations that the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.

NON-UTILITY GENERATION (NUG)

Commission Rule R8-60(i)(2)(iii) requires each electric utility to provide in its biennial IRP report a list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. DEC, DEP, and DNCP each provided a list of NUGs in compliance with this requirement.

DEP reported 11 firm wholesale purchase contracts with a combined capacity of 1,749 MW. DEP also reported 856.1 MW of customer-owned generation in North Carolina and 156.4 MW of customer-owned generation in South Carolina. In addition, DEP receives approximately 95 MW from Southeastern Power Administration (SEPA) for wholesale customers located within DEP's control area.

DEC reported 20 firm wholesale purchase contracts with a combined capacity of 231 MW. DEC also reported 316.8 MW of customer-owned generation in North Carolina and 40.6 MW of customer-owned generation in South Carolina as of June 2014.

DNCP reported nine NUGs with a combined capacity of 1,747.4 MW, which it included in its IRP as firm capacity. DNCP also reported ten "behind the meter" (BTM) NUGs in North Carolina with a combined capacity of 30.8 MW, and 19 BTM NUGs in Virginia with a combined capacity of 217.3 MW. These BTM NUGs are considered non-firm and were not included in DNCP's IRP as firm capacity. DNCP also reported other customer-owned generators of 53.4 MW in North Carolina and 2,795.9 MW in Virginia, which also were not included in its IRP as firm capacity.

WHOLESALE CONTRACTS FOR PURCHASE AND SALE OF POWER

Each utility, with the exception of DNCP, provided a list of firm wholesale purchased power contracts; DNCP stated that its contracts with NUGs are considered firm capacity resources and are included in its IRP. In addition, each utility provided a discussion of recent and pending RFPs and a list of firm wholesale power contracts during the planning horizon in compliance with Rule R8-60(i)(4).

[7] http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html?emc=eta1&_r=0

TRANSMISSION FACILITIES

Pursuant to the 2014 IRP Order, the electric utilities included a copy of their most recent FERC Form No. 715 (Annual Transmission Planning and Evaluation Report) and discussed with the Public Staff detailed information concerning their transmission line inter-tie capabilities, transmission line loading constraints, planned new construction and upgrades, and NERC compliance within their respective control areas for the planning period under consideration. Each electric utility appears to be in compliance with the Commission's filing requirements and NERC transmission reliability standards.

DSM AND EE

The Public Staff's review of the DSM/EE forecasts and programs indicated that each IOU complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. Each IOU included information about its respective DSM and EE portfolios[8] that is largely the same as reported in the 2013 IRPs. Each IOU's forecast of DSM and EE resources and the forecast of peak demand and energy savings from those programs was slightly different from the forecast in the last IRP, but none changed by more than 10%, so no explanation of the drivers behind those changes was required. Unlike last year, DEP and DEC presented their DSM/EE forecast data in the same manner, allowing a clearer understanding of each utility's DSM/EE projections. Finally, as recommended by the Public Staff in its comments on the 2013 IRPs, all three utilities separately delineated the existing EE savings that were incorporated in the load forecasts.

According to the Public Staff, the IOUs included a discussion of new initiatives to expand their DSM/EE portfolios. DNCP currently has three new programs before the Virginia State Corporation Commission, which it intends to file in North Carolina later this year. DEP discussed five programs being considered for implementation (three were approved for implementation in December 2014). DEC did not offer any specific programs being considered for future implementation.

The Public Staff also notes that DNCP completed a new market potential study in late 2014, but indicated to the Public Staff that the findings of the study were still being reviewed at this time before being released. Both DEP and DEC updated their studies in 2013.

With respect to TOU and other curtailable service rates, DEC and DEP are both conducting pilot TOU studies to determine the feasibility of new TOU and curtailable rate schedules. Those studies are ongoing and are expected to produce results in the next two years. The Public Staff continues to recommend that the IOUs implement all cost effective DSM and EE, and also TOU rate schedules. As discussed earlier

[8] For purposes of these comments, the Public Staff includes time-of-use (TOU) rate schedules in its discussion of DSM and EE.

in these comments, greater emphasis on meeting the wintertime peak demands may warrant reevaluation of DSM and TOU resources.

ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE ENERGY RESOURCES

Commission Rule R8-60(i)(7) requires each utility to file its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. Each utility must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. Each utility provided the information required by Commission Rule R8-60(i)(7).

EVALUATION OF RESOURCE OPTIONS

Commission Rule R8-60(i)(8) requires each utility to include in its IRP a description and summary of the results and analyses of potential resource options and combinations of options. The IOUs indicate in their IRPs that they use accepted models that identify the least-cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner. DEP and DEC utilize the System Optimizer and Planning and Risk models to determine the dispatch and production costs for their system; DNCP utilizes the Strategist model.

DEP’ S AND DEC’ S JOINT PLANNING SCENARIO

The Public Staff noted that DEP and DEC included in their IRPs a Joint Planning Scenario that examines the potential for them to share capacity,[9] as compared to the JDA, which allows non-firm energy transactions. A shared capacity arrangement between DEC and DEP would require approvals from the FERC, as well as the North Carolina and South Carolina utility regulatory commissions. If allowed, the Joint Planning Scenario produces a total present value revenue requirement (PVRR) savings of approximately

[9] Regulatory Conditions imposed in the Merger Order require DEP and DEC each to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission. The 2014 IRPs filed by DEP and DEC, and specifically the Joint Planning Scenario, appear to comply with this requirement.

$300 million over the 2029 planning horizon by delaying the need for two 866 MW combined-cycle units (CC) by one year and eliminating the need for 396 MW from two combustion turbine units (CT). As noted, this portfolio spans a fifty-year period and includes three new nuclear units shared by DEP and DEC, which would help to maintain current nuclear capacity and fleet generation diversity as the existing nuclear units are retired.

QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND REDUCED RISK

The Public Staff observed that the evaluation of resource options in the IRP is an ongoing process. Deferring decisions may provide more certainty in resource planning and reduce the likelihood of selecting a resource mix that is not least-cost. A more diverse generation portfolio may mitigate future cost variability and the risk of relatively high energy prices in the future. However, the benefits of avoiding potentially high prices must be weighed against the known costs and the potential for unknown costs of building new generation, particularly nuclear.

The Public Staff recommends that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Public Staff also recommends that the utilities provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions. A calculated rate impact on a levelized per kilowatt-hour (kWh) basis would provide a clearer understanding of the ratepayer impacts of future portfolios. If it would make the rate impact study for each portfolio less complicated and burdensome to perform, the utilities could calculate only the impact of the annual revenue requirement on the Company's average overall rates for the last year of the 15-year plan.

NATURAL GAS ISSUES

Ordering Paragraph No. 15 of the 2014 IRP Order, required:

> That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

In the Commission's May 7, 2013, Order Approving Rules, Requesting Comments, and Establishing Requirements for Electric Integrated Resource Plans to be Filed in 2014 in Docket No. M-100, Sub 135 (*Sub 135 Order*), the Commission detailed these natural gas issues:

- The potential risks inherent in their [the electric utilities'] increasing reliance on natural gas as a generation fuel and the long-term adequacy of North Carolina's gas infrastructure.

- The electric utilities' plans for procuring the additional gas supplies that would be required by the generation proposed in their IRPs.
- The electric utilities' plans to ensure long-term gas supply reliability and adequacy.
- The electric utilities' understanding of how much additional pipeline infrastructure will be needed, and when, due to the combined needs of gas distribution companies and existing and proposed gas-fueled electric generation.
- The advantages and disadvantages of a second major pipeline being built through North Carolina, and the electric utilities' understanding of the steps that would need to occur to effectuate such construction.

In its comments. the Public Staff concluded that DNCP, DEC, and DEP have made a reasonable assessment of their needs for natural gas infrastructure in order to meet their growing dependence on natural gas to provide electric generation. They also have demonstrated their understanding of how an interstate pipeline is planned, approved, and built, including the open season period to determine the market for the pipeline and associated costs. Additionally, the IOUs are knowledgeable about the natural gas supply market, as well as the pipeline planning and build-out in order to move the natural gas supply to their electric generation facilities. It appears that the Atlantic Coast Pipeline (ACP) will be the second major natural gas pipeline into the State of North Carolina. The utilities have adequately set out the benefits of this additional pipeline. The Public Staff recommends that the electric utilities and the natural gas distribution companies continue to work together in planning for adequate pipeline capacity to meet electric generation needs. The Public Staff also recommends that the electric utilities consider natural gas electric generation facilities that also can operate on an alternate fuel.

The Commission finds and concludes that DEC, DEP and DNCP have complied with all Rule R8-60 requirements in their respective 2014 IRPs. Each has provided acceptable 15-year peak and energy forecasts of native load and other firm loan requirements and obligations, as well as supply-side and demand-side resources expected to satisfy these loads. The reserve margins provided by the IOUs are reasonable for planning purposes and are approved.

Each IRP includes a full discussion of the utility's DSM programs and their use as required by Rule R8-60. DEC's Cliffside Unit 6 Carbon Neutrality Plan continues to show a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

The Public Staff, in its comments submitted on March 2, 2015, provided 11 specific recommendations regarding the utilities' IRPs. They are discussed in the following section of this Order. Several additional issues, raised by various other intervenors, along with responses by the utilities, appear later in this Order.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 4

UTILITY RESPONSES TO SPECIFIC PUBLIC STAFF RECOMMENDATIONS REGARDING IRPS

1. **In future IRPs, the utilities should include a discussion of the potential implications of the EPA Clean Power Plan, scenarios for possible compliance, and the costs of compliance**.

DEC/DEP

Because the Clean Power Plan (CPP) Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule, it is difficult for the Companies to model what the exact impacts of the rule will have on the DEC and DEP IRPs. Answers to questions such as, "will the limits be rate or mass based?" and "which units will be included under the plan?" can have significant impacts on the IRP. For example, there is significant debate over the inclusion of carbon emissions from new natural gas combined cycle units. Given these uncertainties, the five scenarios presented in the DEC and DEP 2014 IRPs were evaluated with and without a carbon tax that coincided with the proposed onset of the CPP in 2020. A discussion of the impacts of the carbon tax on the initial resource needs, new nuclear selection, renewable generation, gas firing technology options, and energy efficiency was included in Appendix A of the IRP.

It must be noted that EPA's proposed CCP Rule is not a rule specific to a utility, but rather a state level rule requiring some form of CO_2 limits at the state level rather than the unit-specific or utility-specific level. Section lll(d) outlines the process by which a State Implementation Plan (SIP) would be developed by each of the states. Ultimately, the SIP will dictate the rules and procedures the state will mandate for each of the effected organizations that emit CO_2. The Companies respectfully submit that it is simply premature to include a proposed CPP compliance plan along with associated costs at this point in time.

DNCP

The Public Staff recognizes DNCP’s inclusion of Plan F: EPA GHG Plan for illustrative purposes in the 2014 Plan. Plan F was designed to illustrate a potential compliance scenario of how the Company could meet the proposed 2030 targets under the proposed Section 111(d) rule. The Public Staff commended DNCP for beginning to evaluate its CPP-compliance options, and recommends that the utilities’ future IRPs “include discussion of the potential implications of the [Section 111(d)] Rule, scenarios for possible compliance, and costs of compliance.”

The Company included the Plan F scenario in its 2014 Plan because it views planning for implementation of a final Section 111(d) rule as a prudent step given the proposed CPP rule’s complexities and timelines for compliance. The Company agrees with Public Staff that its future IRPs should continue to plan for CPP compliance. During its 2015 Regular Session, the General Assembly of Virginia enacted Senate Bill 1349, which was signed into law by Governor McAuliffe on February 24, 2015. Senate Bill 1349 adjusts the Virginia resource planning process by 1) moving the 2015 IRP filing date to July 1 and requiring IRPs to be filed annually by May 1 beginning in 2016; 2) requiring future Virginia IRPs to address the effect of current and pending state and federal environmental regulations on existing generation facilities and new generation options; and 3) requiring future Virginia IRPs to evaluate the most cost-effective means of complying with state and federal environmental regulations, including options to minimize effects on customer rates. In recognition of the new resource planning obligations imposed by recently-enacted Senate Bill 1349, DNCP expects its future system-wide Plans to respond to the Public Staff's recommendation that future integrated resource planning address CPP compliance and the costs of compliance.

2. DEC should continue to review its forecasting models carefully, including planned changes to identify further improvements.

DEC/DEP

The Public Staff concluded that both DEC and DEP's load forecasts and methodologies were reasonable for planning purposes. The Public Staff nonetheless commented that its review of DEC's five-year peak load forecasting accuracy based upon the DEC forecasts for 2010-2014 filed in DEC's 2009 IRP indicates a forecast error of 5%. The Public Staff recommended that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements. As it has discussed in recent previous IRP reply comments, and in discussions with the Public Staff, DEC's forecasting error rate in the 2008-2009 timeframe mostly resulted from the severe economic downturn that occurred in 2009 and which no one reasonably foresaw. DEC suffered more than DEP and most utilities in the 2009 recession due to its large amount of industrial load, particularly from textiles. In contrast, the DEC peak forecast developed in 2010 projected a 2013 value that was only 131 MW different than the actual weather adjusted value for the year 2013. Thus, DEC acknowledges the anomaly in the load forecast caused by the severe economic downturn, but appreciates the Public Staff's conclusion that the load forecast included in the 2014 IRP is reasonable. The Companies note that their forecasting methodology is always evolving in an effort to further improve the process, as a result of post-merger best practices and otherwise.

3. The companies should review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.

DEC/DEP

DEC stated that it certainly understands the importance of the long-term peak forecast's impact on future expansion plans. As such, DEC regularly reviews its peak forecasting methodology to ensure adherence to the latest industry standards. Given the increasing importance of efficiency trends on energy usage, DEC now incorporates

Statistically Adjusted End Use Models (SAE) in its peak forecasting process. SAE models attempt to incorporate the effects of naturally occurring energy efficiency trends into the forecast as well as the expected impacts of government mandates. This approach also has the advantage of generating a forecast for each month rather than simply a seasonal forecast. In the Spring 2015 Forecast, the SAE methodology appeared to produce a slightly lower summer peak forecast, but a slightly higher winter peak forecast, which matches recent trends.

4. The companies should ensure that DSM resources identified in the IRP represent the reasonably expected load reductions available at the time the resource is called upon as capacity.

DEC/DEP

The Companies include expected summer DSM resources and reasonable corresponding load reductions in the IRP for planning purposes. Furthermore, DEC and DEP calculate expected DSM load reductions on a daily basis, known as the Load Reduction Capability (LRC), and are based on a rolling twelve weeks' worth of historical load data. These daily LRC calculations are utilized by the Companies' system operators in planning and operating the DEC and DEP systems. DEC and DEP utilize DSM programs in conjunction with system planning, not only for economic reasons. Daily system dynamics, including but not limited to weather, customer operational adjustments and interests, day of the week, and time of day, impact the load curtailment actually achieved and therefore will always vary from the summer DSM capacity contained in the IRP for planning purposes. It is important to note that DEC and DEP have contracts in place with customers to curtail their load pursuant to Commission-approved DSM programs, but beyond the monetary penalties that are provided for in the contracts, the Companies cannot control an individual customer's behavior in response to a request to curtail load.

DNCP

Specific to DNCP, the Public Staff asserted that DNCP's realized DSM capacity reductions were below the amount forecast in its 2014 Plan, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively. The Public Staff recommends that DSM resources identified in the IRP should “represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity” based upon enrolled DSM capacity and evaluation, measurement, and verification (EM&V) data. The Company is generally not opposed to this suggestion and incorporates actual performance and/or EM&V data into its planning process when appropriate and when the Company has sufficient program experience.

5. **The Companies should put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.**

DEC/DEP

The Companies continually review potential new DSM programs and seek input on such programs as part of the EE stakeholder collaborative groups in place for both DEC and DEP.

DNCP

The Public Staff's comments highlight the recent winter system peak demands experienced by DNCP and the other utilities, and recommends the Company employ a "renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands." DNCP agrees with the Public Staff that its most recent experience during 2014 and 2015 suggests that renewed planning focus on peak demands experienced during the winter months may be warranted. During the "polar vortex" periods of January and February 2014, the PJM DOM LSE zone experienced a 16,834 MW system peak demand on January 7, 2014. Most recently, on February 21, 2015, at 8:00 a.m., DNCP experienced its all-time system peak of 18,687 MW, which is up from the 16,834 MW prior system peak experienced in 2014. Recognizing this recent winter peaking experience (and that the recent surge of proposed solar photovoltaic generation is of extremely limited capacity value during winter morning peaks), DNCP will evaluate DSM program options that provide reliable capacity to meet peak demands during both the winter and summer periods in future IRPs. Specifically, the Company continues to evaluate options for cost effective DSM programs that provide benefits during peak periods. The Company also notes that its Virginia commercial distributed generation program provides DSM capacity during both summer and winter periods, but was not approved for deployment in North Carolina.

6. **The IOUs should consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.**

DEC/DEP

The Companies plan to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of their customers they will pursue second license renewal (SLR) for our plants. At this point, no license extension for the operation of nuclear plants beyond 60 years has been issued.

The NRC has indicated that it plans to use the same process for SLR as it used during the initial license renewal; however, this only addresses the process to review the renewal application and not any additional requirements that the NRC may impose to extend the license from 60 years to 80 years. As for timing, the NRC does not plan to issue its guidance for requirements to extend the license from 60 years to 80 years until the 2017 to 2018 timeframe. The Companies do not anticipate the first SLR applications to be submitted until later this decade, with decisions on SLR not expected until approximately 2022 or 2023.

There is a significant amount of uncertainty regarding the ability to get a license extension as well as the uncertainty of the costs to satisfy NRC requirements should they extend the license. In addition to the uncertainty regarding SLR, there is also uncertainty regarding carbon regulations, environmental regulations, and fuel prices. DEC and DEP believe that the uncertainty combined with the new nuclear long development cycle(10 - 15 years to license and construct) makes it imperative that the Companies plan for these assets as if they will not be available, then adjust the plans as more information becomes available.

DNCP

As described in the 2014 Plan, the Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry, and the Company is mindful of the scheduled license expirations of these units between 2032 and 2040. The feasibility and cost of extending the lives and operating licenses of DNCP’s existing nuclear units was similarly an issue of interest in the Company’s recent Virginia IRP review proceeding. The State Corporation Commission of Virginia (VSCC) specifically directed DNCP to investigate the relicensing option for DNCP’s existing nuclear units in its 2015 IRP filing, including comparing the cost of constructing North Anna 3 to the cost of renewing the licenses of the four existing nuclear units, as well as comparing the cost of retiring the four existing nuclear units to the cost of renewing the licenses for those units.

Accordingly, as the Company plans on a system-wide basis, the Company will provide an analysis of the potential for relicensing its existing nuclear units in its North Carolina IRP update to be filed by September 1, 2015.

7. Each utility should carefully review its projections of solar capacity.

DEC/DEP

In their 2014 IRPs, DEC and DEP assumed full NC REPS compliance, as well as compliance with a placeholder for a potential South Carolina renewable energy portfolio standard. The Companies include all currently signed solar, biomass and hydro contracts and any additional amounts required for full compliance in the later years. Solar providers are rushing to take advantage of the Federal and State tax incentives before their current expiration dates, and as such continue to submit their projects to the interconnection queue. DEC and DEP recently filed their Small Generator Interconnection Consolidated Annual Reports in Docket No. E-100, Sub 113B, which indicate that the projects currently in the interconnection queues for DEC and DEP total over 4,000 MW (nameplate) in both service territories. The vast majority of these projects are solar. Even though there is such a large amount of solar in the queue, the likelihood of these projects coming to fruition is unknown. Typically, only a fraction of these projects actually begin operation. As projects come online, the Companies will continue to sign contracts to ensure full compliance with NC REPS as well as those projects without associated RECs that will not be used for NC REPS compliance, but are qualifying facilities (QFs) under PURPA. The Companies also include the non-compliance renewable projects in the IRP as part of the purchase contracts.

The Companies will continue to monitor the interconnection queue and sign contracts as the facilities actually begin operation.

DNCP

The Company is not opposed to reviewing its solar PV QF projections, similar to all other projections, in developing future Plans. However, as discussed at length in the Commission's recent avoided cost proceeding, Docket No. E-100, Sub 140, the Company's current experience does not support relying on the Company's interconnection queue to determine the solar QF resource capacity that may become commercially operational.

The Company's experience during the recent solar PV QF development surge has been that numerous projects in its interconnection queue are "speculative" and have a low probability of development and commercial operation as a resource that DNCP can rely upon to serve customers. Even where a QF has applied for interconnection, has filed for and obtained a CPCN, and executed a power purchase agreement (PPA), the Company still has little assurance of when or if the facility will be made operational. There are numerous aspects of a typical solar PV development project that will dictate whether it is ultimately constructed, including interconnection costs and constraints, qualification for and monetization of tax credits, securing financing, cost of equipment and construction, and, potentially, finding a buyer for the project. Because the Company has little to no visibility into these variables and little meaningful historical data to assess the percentage of solar QF capacity likely to be deployed, DNCP does not believe it prudent to rely upon the level of solar QF capacity pending in its interconnection queue as a reliable metric for future solar QF deployment in its service territory. In summary, so long as QF developers are not required to make any construction commitments when filing a CPCN or executing a PPA, the Company has very little ability to make meaningful estimates on the volume or timing of such QF development. Therefore, for planning purposes, the Company is limited to using its best estimate about the volume and timing of the QF projects that will ultimately be constructed. As in previous IRPs, the Company will continue to review CPCN filings and PPA status each year at the time of the IRP development and incorporate its best estimate of future QF development.

8. DEP, DEC, and DNCP should maintain their proposed reserve margins as filed.

DEC/DEP

The Companies plan to review their reserve margins in 2015, in response to the recent winter peak loads experienced and the interconnection of increasing amounts of intermittent renewable resources to the DEC and DEP systems. Pending the results of that study, the Companies may seek to update their required minimum planning reserve margin target.

DNCP

DNCP agrees with the Public Staff's recommendation.

9. For future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years.

DEC/DEP

The Companies believe that the current 15-year planning horizon provides the most reasonable outlook for new generation requirements. Extending the required reported planning horizon to twenty years would add an additional level of uncertainty to the IRP reports, as the further out generation is evaluated, the inherently more uncertain the basis for those additions becomes. Additionally, 10 to 15 years matches the time required for licensing and constructing the longest lead time generation the Companies evaluate. Extending the planning period beyond 15 years would add an unnecessary administrative burden to the planning process, particularly in light of the fact that successive plans will certainly change over that additional timeframe. As such, DEC and DEP respectfully submit that having extensive stakeholder debate over planned resources projected for years 16 through 20 would only serve to complicate the annual IRP process while adding little tangible value to the process.

DNCP

DNCP believes that the Public Staff's specific recommendation "for future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years" is unnecessary. In the 2013 IRP proceeding, the Company opposed extending its planning period beyond the 15-year period required by Commission Rule R8-60(c) and (h), as well as Va. Code 56-592 *et seq.* and the VSCC's Integrated Resource Planning Guidelines. The 2013 IRP Order stated that the Commission is "satisfied with [the Utilities'] current 15-year planning periods," but that the Utilities "should always supply additional forward looking comments in their IRPs when warranted to provide adequate background concerning critical infrastructure decision-making." Accordingly, DNCP requests the Commission find that its proposal to provide an analysis of the potential for relicensing its existing nuclear units in its 2015 IRP update is adequate and that there is no need to extend the 15-year planning period at this time.

10. The utilities should continue to develop methods of quantifying the benefits of fuel diversity.

DEC/DEP

As discussed in the Companies' 2013 IRP Update Reply Comments, the Companies believe that this recommendation is already captured as part of the existing IRP process commensurate with Commission Rule R8-60. The Companies' current IRP practices include modeling multiple sensitivities around fuel prices. Furthermore, the Companies show how different resource portfolios perform under these varying fuel prices. Both the quantitative impacts and the qualitative benefits of fuel diversity are fully presented in the IRPs. The Public Staff does not provide a specific recommendation as to what other quantitative metric or method they are recommending and as such it is difficult to ascertain the merits of such additional analysis. The Companies believe that the current approach both quantitatively and qualitatively addresses fuel diversity and is fully adequate.

DNCP

At the outset, the Company would note that its 2014 Plan does not select its Fuel Diversity Plan over the least-cost Base Plan. Instead, the Company recommends a path forward based upon the least-cost Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in the Fuel Diversity Plan. As with any strategic plan, the Company will update its future Plans to incorporate new information as it becomes known.

In response to the Public Staff's Recommendation in the 2013 IRP proceeding, E-100, Sub 137, to establish metrics to quantify the benefits of fuel diversity, the Company's 2014 Plan provides the Section 6.6 "Portfolio Evaluation Scorecard" framework. The Scorecard is designed to evaluate the Base Plan relative to other alternative Plan scenarios based upon the following criteria: Strategist NPV cost results to reflect the least cost option; Rate Stability; fuel and construction cost risk, GHG Emissions, and Fuel Supply Concentration. Figure 6.6.1.1 in the 2014 Plan presents the analysis and criteria scoring under the Scorecard framework, while Figure 6.6.1.2 shows the Scorecard rankings for each planning scenario. The Fuel Diversity and EPA GHG Plans received the most favorable scores on the Scorecard. The results of the 2014 Plan's Scorecard framework supports the Company's planning recommendation to continue following the least-cost Base Plan, while also continuing reasonable development of the Company's Fuel Diversity Plan.

Further, the VSCC's 2013 Virginia IRP Order also requires the Company to "include an analysis of the trade-off between operating cost risk and project development cost risk associated with the Base Plan and the Fuel Diversity Plan" starting in the 2015 Virginia IRP filing. The Company plans to include a probabilistic analysis in the 2015 IRP which will provide a comparative assessment of operating cost risk and project development cost risk for both the Base Plan and the Fuel Diversity Plan. This analysis will further address the value of fuel diversity.

11. The utilities should provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions.

DEC/DEP

The Companies do not believe that providing an estimate of annual rate impacts of proposed resource plans in future IRPs is warranted. First, the Public Staff's recommendation is not part of the statutory requirement of the IRP filing to assist the Commission in fulfilling its responsibility pursuant to G.S. 62-110.1(c) to "develop, publicize, and keep current an analysis of the long-rage needs" for electricity in the State. The Commission has repeatedly held that its approval of an IRP does not constitute approval of any of the individual generation resources contained therein, but that such individual generation resources are considered separately as part of the Certificate of Public Convenience and Necessity (CPCN) process established by G.S. 62-110.1 and Commission Rule R8-61. The Companies respectfully submit that consideration of rate impacts would be beneficial only after a utility has actually decided to construct a given generation plant. It is in a specific CPCN docket, or in a subsequent cost recovery proceeding, therefore, and not in an IRP docket, where rate impacts are appropriately considered. Indeed, Commission Rule R8-61(b)(3)(viii), which became effective January 1, 2015, now requires the filing of "the anticipated impact the facility will have on customer rates" as part of a utility's CPCN application.

Second, each IRP filing represents a "snapshot in time" view of the Companies' preferred resource plans over the 15-year planning horizon. The myriad inputs to the IRP planning process, including but not limited to cost assumptions, load forecasts, expected plant retirements, wholesale contracts, and evolving regulatory requirements necessarily change annually (if not multiple times within a year), as do the selected resource plans and the timing, size and nature of individual supply and demand side resources included within the resource plans. As a result, even if developed for the IRP filing, such annual rate impacts would be of limited value. Third, calculating such annual rate impacts would be an extremely burdensome and time-consuming effort for the Companies. The Companies' IRP planning process is already a year-round endeavor, and adding the annual rate impact estimation as part of the IRP would only add complexity and burden to the process, for limited, if any, benefit.

DNCP

While an estimate of annual rate impacts of resource additions on a levelized per kWh basis may provide some understanding of ratepayer impacts, the Company believes this value would be limited in comparison to the way bill impacts are provided in base rate, fuel, DSM and other ratemaking proceedings. In addition, the Company is concerned that such an additional requirement may be a source of confusion for customers since the Company is not asking for actual cost recovery in the IRP proceeding. Finally, DNCP notes that the Commission did not agree to this recommendation in the 2013 IRP Order.

In sum, while the Company disagrees with the Public Staff's specific recommendations to present PVRR and annual rate impacts of each planning scenario in analyzing its future Plans, the Company through its Portfolio Evaluation Scorecard framework provides a reasonable approach to quantifying the benefits of fuel diversity in its 2014 Plan and will continue to present the results of this analysis in future Plans.

The Commission has reviewed the responses that were provided by DEC, DEP and DNCP to the eleven specific issues raised by the Public Staff. Those responses appear appropriate and adequate to the issues raised. Based on those answers provided in the IOUs' reply comments, the Commission does not find it necessary to require DEC, DEP and DNCP to make any additional changes to their future IRP filings at the present time, other than those discussed in their individual reply comments.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 5

REPS COMPLIANCE PLAN REVIEW

G.S. 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and EE through the REPS. One MWh of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction (or through DSM measures, in the case of electric membership corporations (EMCs) and municipalities). The electric public utilities (DEP, DEC, and DNCP) may use EE measures to meet up to 25% of the general requirements in G.S. 62-133.8(b). One MWh of savings from DSM, EE, or demand reduction creates one energy efficiency certificate (EEC), which is similar to a REC and is used to demonstrate compliance with the REPS. EMCs and municipalities may use DSM and EE to meet the requirements in G.S. 62-133.8(c) without any limits. They may also purchase electric energy from a hydroelectric power facility and use allocations from SEPA to meet up to 30% of the overall requirements. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of G.S. 62-133.8(b) and (c), with the exception of DNCP, which can use out-of-state RECs to meet 100% of the requirements. The total amount of renewable energy or EECs that must be provided by an electric power supplier for the year 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015 and 2016, this amount is 6%.

Commission Rule R8-67(b) provides the requirements for REPS compliance plans (Plans). Electric public utilities must file their Plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The Plans must cover the current year and the next two calendar years, or in this case 2014, 2015, and 2016 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5). The instant docket includes the plans filed by DEP, DEC, and DNCP, which includes plans for their wholesale customers in North Carolina for which they have contracted to provide REPS compliance services.

All three IOUs filed their 2014 Plans as part of their IRP. Immediately below are the Public Staff's comments on DEP, DEC, and DNCP's plans to comply with G.S. 62-133.8(b), (c), and (d), the general and solar energy requirements, followed by consolidated comments on plans to comply with G.S. 62-133.8(e) and (f), the swine waste and poultry waste resource requirements.

<u>**DEP**</u>

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for itself and the electric power suppliers for which it is providing REPS compliance services. DEP is contractually obligated to secure resources to meet all the REPS requirements of the City of Waynesville and the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville (collectively, DEP's Wholesale Customers).

DEP intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric QFs with a capacity of 10 MW or less will also provide RECs for DEP's retail customers. DEP will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEP and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. DEP also plans to use the increased availability of solar energy to help it meet the general requirement.

To meet the solar requirement, DEP will obtain RECs from its residential solar PV program and from other solar PV and solar thermal facilities.

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files its EM&V plan for each EE program as part of its request for Commission approval of the program.

DEC

The Public Staff noted that DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. DEC is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford EMC, Blue Ridge EMC, the City of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities of 10 MW or less, together with the increased capacity of DEC's Bridgewater hydroelectric facility following its modification in 2012, will provide RECs toward DEC's REPS obligation. DEC will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEC and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. However, DEC has reduced its reliance on biomass for future REPS compliance because of the increased availability of solar energy and other renewable resources. DEC expects to use solar resources to satisfy some of its REPS requirement.

To meet the solar requirement, DEC will obtain RECs from its self-owned distributed solar PV facilities and from other solar PV and solar thermal facilities.

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEC filed an update to its EM&V plan in its 2014 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1050.

DNCP

The Public Staff stated that DNCP has contracted for and banked sufficient RECs to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased out-of-state wind RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself. For Windsor's general REPS requirement, DNCP plans to use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar requirements, DNCP plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DNCP will rely on out-of-state RECs to meet most of its compliance requirements, as allowed by

G.S. 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement.

DNCP anticipates that it will incur relatively high research and development costs in 2014 and 2015 for its Microgrid Project, but these costs should be minimal in 2016. The Microgrid Project consists of wind and solar energy generation and storage at DNCP's Kitty Hawk District Office with fuel cells possibly added in 2015. The high costs in 2014 and 2015 are due to construction costs. DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP filed an update to its EM&V plan in its 2014 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 513.

REPS COMPLIANCE COMPARISON TABLES

The Public Staff prepared the tables in this section from data submitted in the DEP, DEC, and DNCP Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales in the 2014 column are projected sales for calendar year 2013. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year.

The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services.

TABLE 1: MWh Sales for preceding year

	Compliance Year		
Electric Power Supplier	**2014**	**2015**	**2016**
DEP	36,091,870	38,431,441	38,894,821
DEC	58,813,405	60,013,663	60,658,787
DNCP	4,358,551	4,186,914	4,256,454
TOTAL	99,263,826	102,632,018	103,809,062

Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps, which increase significantly in 2015 due to the residential cost cap increasing from $12 per year to $34 per year.

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DNCP
2014	Incremental Costs	23,630,618	17,768,556	1,103,132
	Cost Cap	43,915,738	63,070,639	4,017,364
	Percent of Cap	54%	28%	27%
2015	Incremental Costs	22,106,981	20,805,290	1,432,489
	Cost Cap	71,350,928	103,084,760	6,246,082
	Percent of Cap	31%	20%	23%
2016	Incremental Costs	28,043,011	24,822,911	1,484,093
	Cost Cap	72,044,678	104,218,833	6,239,114
	Percent of Cap	39%	24%	24%

SWINE WASTE AND POULTRY WASTE REQUIREMENTS IN G.S. 62-133.8(E) AND (F)

In its comments, the Public Staff stated that some electric power suppliers indicated in their Plans filed in 2011 that they were having difficulty in obtaining RECs to comply with the swine and poultry waste requirements in G.S. 62-133.8(e) and (f), which required them, beginning in 2012, to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste.

In May 2012, the Commission issued an order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts to meet these compliance requirements. Most electric power suppliers responded by filing a joint motion seeking to delay the swine and poultry waste requirements as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they had had difficulty acquiring RECs to meet the swine and poultry waste requirements because the technology for animal waste-to-energy facilities was still in its infancy and would need more time to reach maturity.

In November 2012, the Commission issued an order that eliminated the swine waste set-aside for 2012 and delayed the poultry waste set-aside until 2013. This order required DEP and DEC to file tri-annual reports describing the state of their compliance with the set-asides and reporting on their negotiations with the developers of swine and poultry waste-to-energy projects. The Order further required them to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

On September 16, 2013, many of the electric power suppliers filed another joint motion to delay the swine and poultry waste set-asides, similar to the request they filed in 2012. In this proceeding, the Commission issued a Notice of Decision and Order on December 20, 2013, that delayed the swine and poultry waste set-asides until 2014. The Order extended the tri-annual reporting to DNCP and most other EMCs and municipal electric systems. It also requested that the Public Staff hold stakeholder meetings in 2014 and 2015 to facilitate compliance with the swine and poultry waste requirements. The Commission issued a final Order on March 26, 2014.

On August 28, 2014, many of the electric power suppliers filed a joint request to delay the swine waste requirement for one more year, and the Commission granted the request in an Order dated November 13, 2014. The electric power suppliers did not request to delay the poultry waste requirement, and the Public Staff believes that 2014 will be the first year that the electric power suppliers will be able to comply with this requirement as modified by the Commission. One reason that the electric power suppliers did not request a delay in the poultry waste requirement is the relatively low requirement of 170,000 MWh or equivalent energy in 2014 and the utilities' ability to bank RECs from earlier years. In addition, the availability of poultry waste RECs in the marketplace has been increased due to advances in the technology of power generation from poultry waste, and by the use of thermal energy to meet the requirement as authorized by N.C. Session Law 2011-309, and by the availability of poultry waste RECs from "cleanfields renewable energy demonstration parks," as authorized by N.C. Session Law 2010-195.

On June 23 and December 3, 2014, the Public Staff held stakeholder meetings as requested by the Commission. The attendees included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, state environmental regulators, and the electric power suppliers. The Public Staff believes that the meetings were made productive by allowing the stakeholders to network and voice their concerns to the other parties. The Public Staff intends to hold two more meetings in 2015 as requested and believes that they will be useful. However, the Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste requirements for at least the next two years. The poultry waste requirement will more than quadruple from 170,000 to 700,000 MWh in 2015 and rise to 900,000 MWh in 2016. No electric power supplier requested a delay in the poultry waste set-aside for 2014, but both DEP and DEC have stated that they are "uncertain" that they can meet the poultry waste requirement in 2015 and beyond. The Public Staff agrees that the capacity of poultry waste-to-energy facilities may not be sufficient to generate enough RECs for 2015, and possibly not 2016. DNCP is in a better position because it can obtain all of its RECs from out of state.

The swine waste-to-energy industry has a few facilities operating in North Carolina, but its generation is very small relative to the need for approximately 70,000 MWh of in-state swine waste energy per year to meet the Commission's Order of November 13, 2014. Swine waste-to-energy facilities cannot earn RECs from thermal energy as poultry facilities can; however, they would probably be limited in thermal capacity even if thermal energy were allowed to earn RECs for several reasons, including differences in the energy content of each fuel on a volumetric basis and technological differences between the waste-to-energy facilities utilizing each fuel type.

The lack of swine and poultry waste-to-energy facilities is the result of: (1) limited technology development and expertise because currently North Carolina is the only state with swine and poultry waste requirements; (2) the utilities' reluctance to commit to expensive purchase contracts for speculative technologies; (3) limited availability of financing; and (4) uncertainty over REC prices.

PUBLIC STAFF'S CONCLUSIONS ON REPS COMPLIANCE PLANS

In summary, the Public Staff's conclusions regarding the REPS compliance plans of DEP, DEC, and DNCP are as follows:

1. The compliance plans of DEP, DEC, and DNCP indicate that they should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste requirements, without nearing or exceeding their cost caps.

2. DEP, DEC, and DNCP will have difficulty meeting the Commission's revised swine waste requirements in 2015 and 2016, and DEP and DEC will have difficulty meeting the poultry waste requirements. However, they are actively seeking energy and RECs to meet these requirements.

3. The Commission should approve the REPS compliance plans filed by DEP, DEC, and DNCP in 2014.

The preceding pages provide the Public Staff's utility-by-utility review of the REPS compliance plans submitted by the IOUs. Based on the Public Staff's review, it provided its conclusions on these plans as shown above and recommends that the Commission approve the REPS compliance plans filed by DEP, DEC and DNCP in 2014. The Commission concurs with this recommendation and therefore approves the REPS compliance plans submitted by the utilities with their 2014 IRPs.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 6

ADDITIONAL ISSUES RAISED IN INTERVENOR COMMENTS

NCSEA

Energy Storage

In its initial comments, NCSEA requested that the Commission amend Rule R8-60(e) to include utility-scale energy storage as an alternative supply-side energy resource. NCSEA further requested that the Commission amend Rule R8-60(i)(10) to focus on smaller-scale energy storage. NCSEA proposed the following amendment to Rule R8-60(e):

> Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, ~~and biomass~~. biomass, and utility-scale energy storage.

NCSEA likewise proposed the following amendment to Rule R8-60(i)(10):

> Smart Grid Impacts. -Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.
>
> For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data -essentially establishing a two-way communication protocol.
>
> For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, small-scale energy storage, demand response, demand- side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

The information provided shall include:

> (a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.
> (b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.
> (c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

NCSEA requested that the Commission direct the utilities to use the best available model to consider energy storage during the IRP process. Because of the current lack of models that best integrate energy storage, at this time the directive would mean that the utilities use their current best practices and existing models. When more appropriate models become available, they should be used by the utilities for future IRPs.

In their joint reply comments, DEC and DEP responded that NCSEA does not appear to have any criticism of the DEC and DEP IRPs, but instead asks the Commission to amend Rule RS-60(e) to include utility-scale energy storage as an alternative supply-side energy resource and amend Rule R8-60(i)(10) to list small-scale energy storage as a smart grid technology.[10] While the benefits of advanced energy storage are obvious, the costs and practical applications of energy storage on a macro-level are less known. As the costs of this technology decline and impacts of energy storage on the grid come into clearer focus in the coming years, it may be a beneficial addition to the Companies' IRPs, but until then, it would not be prudent to include these systems. The Companies continue to monitor advanced energy storage technologies and evaluate potential uses in the Carolinas. However, at this time these technologies are neither economical, nor viable on a macro level for use in the IRP. The Companies will include Li-ion battery storage technology in the economic supply- side screening process as part of the 2015 IRP.

In its reply comments, DNCP explained that it does, in fact, evaluate energy storage in its 2014 Plan (as recognized by NCSEA's comments), finding that while "batteries have gained considerable attention due to their ability to integrate intermittent generation

[10] NCSEA spends approximately half of its Initial Comments field March 2, 2015, summarizing the DEC and DEP IRPs. The Companies note that NCSEA's Figures 2 and 3 at pp. 15-16 of its Comments omit the Companies' generation facilities located in South Carolina, which also serve the Companies' North Carolina customers.

sources, such as wind and solar on the grid the primary challenge facing battery systems is the cost."[11] The Company plans to continue to evaluating energy storage options in future IRPs. However, DNCP does not view NCSEA's anecdotal support for the expected maturation of energy storage to a least-cost resource as trumping reality. Further, as NCSEA concedes, models do not currently exist today to fully evaluate the costs and benefits of energy storage. Therefore, DNCP questions the utility of recommending that the utilities be required to "take their best shot" at modeling energy storage. Instead, energy storage should continue to be evaluated under R8-60(i)(10), as a smart grid resource that can be integrated – if cost effective – to "improve the operational integration of distributed and/or intermittent generation sources." Finally, DNCP objects to NCSEA's procedural approach, which it characterizes as "lobbing its proposed revision to Rule R8-60(e) into this IRP review proceeding." DNCP states that NCSEA's request blurs the purpose of this proceeding, as established by the Commission's September 29, 2014, Order Establishing Dates for Comments on Integrated Resource Plans, REPS Compliance Plans and REPS Compliance Reports. According to DCNP, in past proceedings, both the Company and NCSEA have taken the procedurally-more-appropriate tact of foreshadowing a future request to modify a rule in a separate proceeding or requesting the Commission to initiate a rulemaking and NCSEA should have taken that tact here also. In sum, while DNCP submits there is little merit to NCSEA's recommendation to modify Rule R8-60(e), it argues the more appropriate place to consider such a request (if the Commission is inclined to do so) would be a separate rulemaking proceeding.

The Commission agrees with DEC, DEP and DNCP that these technologies are not economical or viable at this time for mandatory inclusion in the utilities' IRPs. Further, as models do not currently exist for a proper evaluation of energy storage, the Commission does not see a benefit in simply asking the IOUs to take their best shot at a modeling approach at this time.

MAREC

Wind Energy

According to MAREC in its comments, wind energy costs have fallen by 58% over the past five years, and wind energy represents an increasingly competitive form of energy. However, DEC's and DEP's IRPs project very little use of wind energy throughout the planning period.

MAREC recommends that the Commission direct DEP and DEC to revise their IRPs to include additional consideration of cost-effective wind resources in order to provide additional resource diversity both for meeting REPS requirements and in preparation for EPA's Clean Power Plan compliance. MAREC pointed out that, in its order approving DEC's and DEP's 2012 IRPs, the Commission held that the two companies "should continue to assess alternative-supply side resources such as wind energy on an ongoing basis." The Commission further ordered that the utilities "should consider

[11] 2014 Plan, at 62-63.

additional resource scenarios that include larger amounts of renewable energy resources and to the extent those scenarios are not selected, discuss why the scenario was not selected."

MAREC concluded its comments with the following recommendations:

- The Commission should direct DEC and DEP to continue to evaluate the market price of all renewable energy resources for REPS compliance, including seeking additional renewable energy diversity when prices of various resources are comparable.
- Given the downward trend in wind energy costs, the Commission should direct DEC and DEP to continually seek feedback from the market on current wind energy prices and evaluate wind energy competitiveness not just for REPS compliance, but for competition with conventional generation resources.
- The Commission should direct DEC and DEP to include wind energy pricing in future cost sensitivity analyses.
- In light of DEC's and DEP's expectation for carbon dioxide legislation and the pending finalization of the Clean Power Plan, the Commission should direct that DEC's and DEP's generation screening alternatives continually evaluate whether renewable energy, energy efficiency and renewable energy/gas hybrid scenarios are a cost effective means to meet CPP goals.

In their joint reply comments, DEC and DEP responded that DEC's 2014 IRP base case includes 860 MW of renewable resources by 2019 and 2,155 MW by 2029, which includes 150 MW of wind. DEP's 2014 IRP base case includes 907 MW of renewable resources by 2019 and 1,187 MW by 2029, which includes 100 MW of wind. DEC and DEP explained that MAREC does not appear to appreciate, however, that both Companies' 2014 IRPs also included a High EE and High Renewables portfolio, which evaluated an assumed requirement to serve approximately 10% of each Company's combined retail load with new renewable resources by 2029—which represents over twice the amount of renewable energy as compared to the base case. The DEC High EE/Renewables portfolio included 427 MW of nameplate wind and the DEP High EE/Renewables included 289 MW of nameplate wind. The purpose of the scenario is to show how the Companies' resource plans would be affected in the event that additional cost-effective renewable and energy efficiency resources are identified or mandated. A key takeaway is that, in such an event, some traditional resources can be eliminated or deferred but significant levels of traditional resources such as new nuclear and natural-gas combined cycle are still needed.

According to DEC and DEP, the main locations for wind energy generation in the Carolinas are the North Carolina mountains and on-shore coastal regions. With ridge laws prohibiting wind turbine construction in the North Carolina mountains and siting issues along the coast, there are real physical limitations to the amount of wind power that could be built in the Carolinas currently. DEC and DEP, collectively, only have one wind project in the interconnection queue: a very small project of only approximately 2.5 kW. While the National Renewable Energy Laboratory study cited by MAREC may have determined a large potential for North Carolina wind projects, the prohibitive laws and siting issues continue to hinder wind facility construction in the North Carolina mountains or coast.

DEC and DEP believe that they have adequately considered wind and all other potential renewable energy resources in preparing their 2014 IRPs. They state that Duke Energy Corporation, the parent company of DEC and DEP, is one of the largest wind energy developers in the United States and recognizes the valuable potential that new wind energy resource development can provide. In their IRPs, however, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best met the Companies' needs to provide the reliable, least-cost resource mix as required by North Carolina's integrated resource planning and REPS laws. DEC and DEP noted that, it is for these reasons, that they Companies maintain a reasonable total of 250 MW of wind resources in their plans.

The Commission finds that DEC and DEP have adequately responded to the issues raised by MAREC related to wind energy. No further action is necessary at this time.

<u>SACE and Sierra Club</u>

<u>Renewables, Energy Efficiency and Environmental Compliance Costs</u>

The initial comments of SACE and the Sierra Club stated that the 2014 IRPs of DEC and DEP contain limited improvements upon the Companies' previous IRPs, but unfortunately, retain most of the flaws of earlier IRPs. In addition, new assumptions and methods compound the flaws carried over from previous plans, resulting in resource plans that are more costly, more risky, and more polluting than necessary. Key flaws in the 2014 IRPs include the following:

- The Companies are planning to build too much capacity, while underinvesting in resources that would reduce system costs for all customers.
- The Companies do not appear to have evaluated the full range of costs to achieve and maintain compliance with environmental regulations at their coal-fired power plants. For some units, accelerated retirement may be the most economic option.
- As in prior IRPs, the Companies are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. This means system costs for ratepayers will be significantly higher than they need to be.
- The Companies do not plan to maximize cost-effective renewable energy opportunities that reduce risks to customers from rising fuel costs and anticipated regulatory requirements.

SACE and the Sierra Club asserted that, as discussed in comments on previous IRPs, the Companies use inconsistent criteria to evaluate the risks associated with each resource, using criteria that provide support for favored resources while applying different criteria or analytic methods to undervalue energy efficiency and renewable energy. The concerns raised in prior comments with respect to the Companies' inconsistent consideration of risk are only magnified in the 2014 IRPs. The ever-changing criteria for evaluation seem to track the changing economics of DEC's proposed Lee nuclear plant.

SACE and the Sierra Club maintained that the DEC and DEP 2014 IRPs resulted in the selection of preferred resource portfolios that, if implemented by the Companies, would be unnecessarily costly, risky, and polluting. To correct these flaws and minimize costs and risks to ratepayers and the environment, they recommended that the Commission issue an order directing the Companies to implement the following improvements, which are set forth in greater detail in the various sections of SACE and the Sierra Club's initial comments.

- Evaluate the costs to ratepayers of various resources over both the short- and long term, to accurately assess their risks and benefits;
- Clearly disclose the results of any analyses of changes to coal unit operations necessary to comply with forthcoming air, water and waste regulations;
- Plan to achieve the energy efficiency savings targets agreed to in connection with the Duke Energy-Progress Energy merger, and evaluate energy efficiency as a resource that competes on its own merits with supply-side resources and can grow over the planning horizon;
- Explicitly recognize and incorporate the benefits that renewable energy resources provide in addition to capacity and energy, including hedging against fuel cost and environmental compliance cost risks; and
- Study best practices for modeling utility-scale and distributed solar technologies and integrating such analysis into resource plans, and incorporate those practices into development of future IRPs.

In their joint reply comments, DEC and DEP observed that SACE and Sierra Club note that DEC "led the Southeast in energy savings from efficiency," in both 2011 and 2012, and that DEC ranked 2nd in the Southeast in 2013 and DEP ranked 3rd in the Southeast in 2013 in efficiency savings as a percentage of retail sales. Yet, despite these accolades, as in previous IRP comments, SACE and Sierra Club allege that DEC and DEP are not planning to capture all cost-effective EE and maximize renewable energy opportunities. DEC and DEP maintain that they have, however, included significant levels of EE and renewable resources in their 2014 IRPs, as detailed in Appendix D to the DEC and DEP 2014 IRPs.

DEC and DEP stated that on page 6 of the SACE Comments, SACE and Sierra Club state that "DEC's projection of EE impacts peaks in 2025 . . ." and that "DEP's projection of EE impacts peaks around 2021 ...;" however, these statements are incorrect. The Companies' EE forecasts do not peak as claimed, but continue to grow on a cumulative basis until reaching the full achievable market potential as estimated in the Forefront Economics market potential studies previously provided in this and other IRP dockets.

DEC and DEP argued that, contrary to SACE and Sierra Club's arguments, it would be imprudent for the Companies to include projected impacts from EE beyond the levels estimated in the market potential studies. Furthermore, SACE and Sierra Club leave the false impression that the Companies have excluded consideration of EE from its planning process for half of the PVRR study period. This is not correct because the cumulative projected impacts that capture the estimated market potential have been incorporated into the IRP analysis. The EE savings impacts have not been "terminat[ed]" ... "halfway through the planning horizon" as alleged by SACE and Sierra Club; rather, all EE impacts that are reasonably expected to be achievable have been captured in the overall IRP process.

DEC and DEP further argued that SACE and Sierra Club also ignore the fact that both DEC and DEP evaluated two portfolios with High EE targets in their 2014 IRPs. These aspirational EE portfolios averaged $5 billion higher cost than the base portfolio on a PVRR basis. Thus, while the Companies appropriately accounted for EE up to the market potential studies in the base case for the 2014 IRPs, increasing beyond the market potential EE levels would have resulted in a significantly higher-cost resource plan.

The Companies have included in their 2014 IRPs the level of EE they believe is reasonably achievable and economic. In response to a data request seeking the feasibility assumptions of the increased EE levels asserted in their comments, SACE and Sierra Club admitted that they did not conduct a market potential study or make assumptions regarding participation (penetration) rates, or technology to achieve penetration rates, for purposes of preparing their comments, but that their comments were "informed" by their review of market potential studies performed for DEC and other southeastern electric utilities. DEC and DEP asserted that SACE and Sierra Club do not appear to realize that potential does not equal cost-effective or achievable. In their comments criticizing DEC's EE cost assumptions, SACE and Sierra Club again rely upon the LBNL study by Barbose. While this study does make an attempt to adjust cost projections for size of first year impacts, it does not adjust for cumulative market penetration (i.e., the more that has been achieved on a cumulative basis, the higher must be the costs per kWh achieved). Furthermore, the study essentially relies on past spending and impacts to make its projection, which DEC and DEP assert is a very unreliable methodology.

DEC and DEP submitted that, as they did in their 2013 IRP comments, SACE and Sierra Club complain that the EE costs assumed by the Companies in their 2014 IRPs are too high. On pages 8-11 of their comments, SACE and Sierra Club restate four alleged flaws with DEC's EE cost assumptions and methods. As to SACE and Sierra Club's allegation that DEC's long- term EE cost projection included costs incurred by program participants instead of limiting the costs to those paid by DEC. DEC and DEP reply that this allegation is simply false. As to the use of the 60% market saturation, this is based upon the market potential study prepared for DEC and is consistent with reasonable adoption curves for typical measures. As to the criticism that there is no provision for introduction of new EE technology or for reduction in costs of future EE technology, SACE and Sierra Club's comments ignore that generation technology is treated exactly the same way in the IRP (no assumptions are made that generation technology costs will decrease over time). As to their assertion that economies of scale serve to reduce EE program costs as more customers participate, this ignores the reality of EE program implementation: as less expensive EE measures are depleted (the "low hanging fruit"), more expensive measures must be offered.

In addition, DEC and DEP observed that, in part, SACE and the Sierra Club criticize the Companies for not discussing their solar resource capacity value methodology or why the estimates change over time. The Companies have utilized a methodology to determine the peak contribution of solar resources that has been utilized in the current and past IRPs. This methodology simply overlays the solar load profile with the peak hours to determine how much of a solar facility's output can be counted on during the peak hours. The peak hours are those defined in Option B of the avoided cost filing. The load shape in the peak hours determines the amount of capacity that can counted on during each peak hour in both summer and winter periods. These values are summed to determine the overall contribution to peak percentages. A similar methodology is utilized for wind resources. As for these values changing over the years, the Companies continue to review processes and best practices for all methodologies in the IRP. The solar capacity values in the 2014 IRP actually increased as compared to previous years due to the process improvement, thus giving the solar facilities higher value in peak hours.

DEC and DEP also noted that, in their comments, SACE and Sierra Club also allege that DEC and DEP may not have considered current and future environmental regulations, including specifically EPA's Clean Power Plan. Appendix G to both the DEC and DEP 2014 IRPs contain extensive discussion of potential future environmental requirements that will impact the Companies' operations in the coming years, including those related to the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule, the Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards, SO_2 Standards, Particulate Matter Standard, Greenhouse Gas Regulation, Cooling Water Intake Structures (Clean Water Act 316(b)), Steam Electric Effluent Guidelines, and Coal Combustion Residuals. The Companies' maintained that their IRP models build in all known capital and O&M costs for environmental compliance.

DEC and DEP further observed that SACE and Sierra Club focus on the impacts of the Clean Power Plan and their own opinion of which coal plants should be considered for accelerated retirement. At the time of the development of the 2014 IRPs, not enough information was available about the Clean Power Plan and the compliance targets for the Companies to include compliance costs in the analysis. As noted previously, the Clean Power Plan Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule. In addition, the plants in question do have planning retirement dates included in the IRP, based reasonably on the current book value of the plants. As the Clean Power Plan, or any other regulation or legislation becomes more certain, the Companies will perform detailed analysis to determine the impacts to the DEC and DEP systems and to each individual generation plant. The Companies evaluate the retirement dates for all generation units based upon changing circumstances, and update retirement dates accordingly.

DEC and DEP stated that, in response to several data requests, SACE and Sierra Club noted that they "do not purport to offer 'proposed resource additions and mix of resources" in their comments. According to DEC and DEP, “if these parties don't have a proposed alternate resource mix and associated costs to analyze and compare, then it belies the validity of the purported cost-effectiveness of their proposals and frustrates any meaningful consideration of their comments. In conclusion, the Companies assert that their IRPs and REPS compliance plans meet all applicable requirements and any SACE and Sierra Club arguments to the contrary should be dismissed.”

The Commission finds that DEC and DEP have satisfactorily addressed the issues raised by SACE and the Sierra Club in their initial comments and that no further action is required.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission’s current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs’ 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes and are hereby approved.

3. That the 2014 REPS compliance plans filed in this proceeding by the IOUs are hereby approved.

4. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility’s projected reserve margins.

5. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

6. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer’s current supply arrangements and explain the basis for the utility’s reasonable expectation for serving each such customer.

7. That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.

8. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

9. That all IOUs shall continue to include in future IRPs a full discussion of the drivers of each customer class' load forecast, including new or changed demand of a particular sector or sub-group.

10. That pursuant to the Regulatory Conditions imposed in the Merger Order DEC and DEP shall continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

11. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

12. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

13. That to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

14. That future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

15. That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall continue to include with their future IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

16. That NC WARN's motion for an evidentiary hearing shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.

This the __26th__ day of June, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Chief Clerk