BIENNIAL REPORT REGARDING FUEL AND FUEL-RELATED CHARGE ADJUSTMENT PROCEEDINGS FOR ELECTRIC UTILITIES

REQUIRED PURSUANT TO G.S. 62-133.2(g)

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SUBMITTED BY THE UTILITIES COMMISSION

INTRODUCTION

This report is being provided to the Joint Legislative Commission on Governmental Operations pursuant to the provisions of G.S. 62-133.2(g), which requires the Utilities Commission (Commission) to provide reports on July 1 of every odd-numbered year summarizing the proceedings conducted during the preceding two years pursuant to G.S. 62-133.2, the statute providing for fuel and fuel-related charge adjustments for electric utilities.

G.S. 62-133.2 provides for two types of rate adjustments: fuel and fuel-related charge adjustments and “true-ups.” Both types of adjustments take place in the context of a single hearing, but they are separate and distinct and it is important to distinguish between them. A fuel and fuel-related charge adjustment is a prospective adjustment to the fuel cost component of electric rates (the fuel factor) designed to account for changes in the cost of fuel and certain fuel-related cost items as set in the electric utility’s last general rate case (the base fuel factor). This adjustment is based on pro forma data and utilizes an historical 12-month test period. The test period data are used as a guide to what these fuel and fuel-related costs will be in the future. However, no matter how carefully this adjustment is set, it will never perfectly match the costs that the utility actually incurs in the future, and that is why a “true-up” is allowed. The “true-up” looks at data to determine whether the reasonable fuel and fuel-related expenses prudently incurred by the utility were more or less than what had been provided for in the rates collected during that period. A “true-up” is an adjustment to rates by which under-recovered fuel and fuel-related costs are collected by the utility or over-recovered fuel and fuel-related costs are returned to customers. The “true-up” adjustment is referred to as an experience modification factor (or EMF) rider.

Fuel charge adjustments first began in North Carolina during the 1970s, when the price of fuel was escalating rapidly as a result of the Arab oil embargo. The Commission first used its traditional ratemaking powers to establish formulas under which fuel charge factors were added to customers’ bills each month based upon ongoing changes in the cost of fuel. This procedure was challenged in court and was upheld by the Supreme Court in 1976. Meanwhile, in 1975, the General Assembly amended G.S. 62-134 in order to provide a statutory basis for fuel charge adjustment proceedings. In 1982, based upon the recommendation of the Utility Review Committee, the General Assembly repealed the fuel charge adjustment provisions of G.S. 62-134(e) and enacted the predecessor of the present fuel charge adjustment statute, G.S. 62-133.2. Under this statute, fuel charge adjustment proceedings are held once each year for each electric utility that generates electricity by fossil or nuclear fuels to determine whether the fuel and fuel-related cost component of electric rates should be adjusted up (increment rider) or down (decrement rider).

“True-ups” were first introduced in 1985. In a fuel charge adjustment proceeding for Carolina Power & Light Company, the Commission added an “experience modification factor” to rates in order to allow the Company to recover a portion of its previously under-recovered fuel expense. This Order was challenged in court, and in

1987 the Court of Appeals held that G.S. 62-133.2, as then written, did not authorize such a "true-up." On July 24, 1987, the General Assembly amended G.S. 62-133.2 to provide explicitly for "true-ups."

By this same 1987 legislation, the General Assembly provided for repeal of the entire fuel charge adjustment statute in 1989. In 1989, the General Assembly extended the sunset date until 1991. In 1991, the General Assembly extended the sunset date until 1997 and provided for the Commission to report every two years "summarizing the procedures conducted pursuant to G.S. 62-133.2 during the preceding two years and recommending whether this section should be continued, repealed, or amended." In 1995, the General Assembly removed the sunset provision altogether and eliminated the requirement that the Commission recommend in its reports whether G.S. 62-133.2 should be continued, repealed, or amended.

On August 20, 2007, Session Law 2007-397 (Senate Bill 3) was signed into law. This comprehensive legislation, among other things, established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) for North Carolina and provided for REPS cost recovery through a rate rider; provided for cost recovery of demand-side management and energy efficiency expenditures through a separate rate rider; and amended the fuel charge adjustment statute. Originally, the fuel charge adjustment statute, G.S. 62-133.2, provided for a uniform rider to reflect actual changes in the utility's cost of fuel and in the fuel cost component of the electric utility's purchased power. Senate Bill 3 amended G.S. 62-133.2 to remove the requirement that fuel and fuel-related costs be recovered by a rider that is uniform as to all customer classes. Senate Bill 3 also amended G.S. 62-133.2 to allow electric utilities to recover additional costs through the annual fuel charge adjustment. The fuel and fuel-related costs that are now recoverable under G.S. 62-133.2 are:

- The cost of fuel burned;
- The cost of fuel transportation;
- The cost of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (reagents);
- The total delivered non-capacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment;
- The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities that are subject to economic dispatch;
- Except for those costs recovered pursuant to the REPS rate rider, the total delivered costs of purchases of power from renewable energy facilities and new renewable energy facilities pursuant to the REPS requirement or any similar federal requirement; and
- The fuel cost component of other purchased power.

These amendments to G.S. 62-133.2 became effective as of January 1, 2008; they apply to the costs of reagents incurred on and after August 20, 2007, and to other fuel and fuel-related costs incurred on and after January 1, 2008.

SUMMARY OF FUEL CHARGE ADJUSTMENT PROCEEDINGS

Before summarizing the individual proceedings conducted pursuant to G.S. 62-133.2 during the preceding two years, the Commission will provide a brief background on the way the statute is administered.

The statute applies to Duke Energy Carolinas, LLC d/b/a Duke Energy Carolinas, a subsidiary of Duke Energy Corporation (DEC); Duke Energy Progress, Inc. d/b/a Duke Energy Progress, also a subsidiary of Duke Energy Corporation (DEP); and Virginia Electric and Power Company d/b/a Dominion North Carolina Power, a subsidiary of Dominion Resources, Inc. (DNCP). The Commission, following lengthy rulemaking proceedings, adopted Commission Rule R8-55 to implement the statute. A copy of this Rule is attached to this report as Appendix A. The Rule establishes a date certain for each company's annual fuel charge adjustment hearing. The hearing for DEC is held on the first Tuesday of June of each year, the hearing for DEP is held on the third Tuesday of September of each year, and the hearing for DNCP is held on the second Tuesday of November of each year. If a company has a general rate case hearing scheduled close to the date for its annual fuel and fuel-related charge adjustment hearing, the two hearings may be consolidated. However, the issues in the fuel and fuel-related charge adjustment proceeding will be decided separately from the issues in the general rate case. Rule R8-55 also establishes a test period for each company that is uniform from year to year. The test period for DEC is the calendar year, the test period for DEP is the 12-month period ending March 31, and the test period for DNCP is the 12-month period ending June 30.

The burden of proof is on the utility to show that its fuel and fuel-related costs were reasonable and prudently incurred. As previously noted, fuel charge adjustments were originally prompted by fluctuating fuel prices resulting from the Arab oil embargo. More recent fluctuations in fuel expenses have generally been due to the availability of nuclear generating units, a heavier reliance on generating units using fossil fuels to serve the growth in electric load even when all existing nuclear generating units perform at high capacity factors and, most recently, increased fossil fuel costs. The cost of nuclear fuel is far less than the cost of coal and other fossil fuels, and the level of total fuel expense is, therefore, significantly affected by how well a utility's nuclear power plants operate. Thus, the capacity factors for nuclear plants are important considerations in fuel charge adjustment proceedings. Appropriate nuclear capacity factors are crucial both in setting rates for the future and in determining the amount of the "true-up." Only "reasonable fuel and fuel-related costs prudently incurred" are trued-up, and the Commission uses nuclear capacity factors as indications of management efficiency and prudency. In that regard, Rule R8-55(k) specifically provides:

> The burden of proof as to the correctness and reasonableness of any charge and as to whether the test year fuel expenses were reasonable and prudently incurred shall be on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual systemwide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Council's Equipment Availability Report, appropriately weighted for size and type of plant or (b) an average systemwide nuclear capacity factor, based on a two-year simple average of the systemwide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Council's Equipment Availability Report, appropriately weighted for size and type of plant, or a presumption will be created that the utility incurred the increased fuel expense resulting therefrom imprudently and that disallowance thereof is appropriate. The utility shall have the opportunity to rebut this presumption at the hearing and to prove that its test year fuel costs were reasonable and prudently incurred. To the extent that the utility rebuts the presumption by the preponderance of the evidence, no disallowance will result.

While nuclear capacity factors remain an important consideration in fuel charge adjustment proceedings, nuclear plant performance has improved and the nuclear capacity factors have tended to stabilize over the years. However, the existing nuclear units are not capable of generating enough electric energy to meet the total demand for electric energy, even at the highest possible levels of performance. Since the demand for electric energy in North Carolina has grown, the reliance on generating units using more expensive fossil fuels to produce additional energy has also increased, and this is another factor that has contributed to higher fuel expenses and fuel factors. Finally, in more recent years, the unit prices of fossil fuels have increased, which has also impacted utility fuel costs.

The following sections of this report present a summary of each of the six fuel and fuel-related charge adjustment proceedings conducted during the preceding two years in chronological order. Following the summaries, a table showing selected summary information for each of these six fuel and fuel-related charge adjustment proceedings is also attached.

1. DEC – Docket No. E-7, Sub 982

This fuel and fuel-related charge adjustment proceeding for DEC utilized a 12-month test period that consisted of the calendar year 2010. DEC filed the Application and supporting pre-filed testimony with exhibits on March 9, 2011. The Commission held the evidentiary hearing on June 7, 2011 and issued its Order on August 9, 2011.

On May 6, 2011, DEC filed certain revisions to its original request. According to the Company's supplemental testimony, such revisions were filed to update its fuel and fuel-related cost recovery to the 12 months ending April 30, 2011, pursuant to Commission Rule R8-55(d)(3) that allows a utility to update its fuel and fuel-related cost recovery up to 30 calendar days prior to the date of the hearing. In addition, DEC made other revisions to correct errors identified by the Company subsequent to its original filing and by the Public Staff during the course of its investigation of DEC's fuel and fuel-related costs. These revisions did not affect the prospective fuel and fuel-related cost factors proposed by DEC. However, because DEC experienced an over-recovery of its fuel and fuel-related costs during the last three months of the updated period, the proposed EMF riders changed from increments to decrements and thereby reduced the total or net fuel and fuel-related cost factors (the sum of the prospective fuel and fuel-related cost factor plus the EMF) compared to DEC's original request.

DEC requested Commission approval of prospective fuel and fuel-related cost factors of 2.3941¢ per kWh for the residential class, 2.3931¢ per kWh for the general service/lighting class, and 2.3926¢ per kWh for the industrial class. [1] These factors were calculated using an adjusted test period system fuel and fuel-related cost amount of $1,901,733,000. This amount of fuel and fuel-related cost was based, in part, upon a normalized nuclear capacity factor of 92.0%. DEC recommended use of the 92.0% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of outage days scheduled for its nuclear units during the period that the rates established in this proceeding would be in effect. During the test year, DEC achieved an actual nuclear capacity factor of 95.88%. In comparison, the most recent five-year (2005-2009) national average capacity factor for nuclear units similar to DEC's was 90.30%**,** according to the North American Reliability Council's Equipment Availability Report (NERC). Normalization adjustments were also made to the test period data for weather, customer growth, line losses, and unit fuel prices.

The adjusted system period system fuel and fuel-related cost amount of $1,901,733,000 also included $2,884,000 of renewable purchased power capacity costs. G.S. 62-133.2(a2) requires, in pertinent parts, that the annual increase in the amount of such costs that are recoverable under G.S. 62-133.2 cannot exceed two percent of the utility's total jurisdictional revenues in the prior calendar year. In addition, such costs must be allocated among the customer classes as determined by the Commission in a general rate case of the Company and recovered as a separate

[1] These and all subsequent fuel and fuel-related cost factors and EMFs exclude the gross receipts tax and the regulatory fee.

component of the fuel and fuel-related cost factors. In this proceeding, DEC allocated $1,976,000 of the total system renewable purchased power capacity costs to the North Carolina retail jurisdiction and the annual increase in such costs did not exceed two percent of its jurisdictional revenue for 2010. DEC then allocated the North Carolina retail renewable purchased power costs among the customer classes on the basis of the production plant allocation factors from its 2009 cost-of-service study as required by the Commission Order dated December 7, 2009, in DEC's general rate case, Docket No. E-7, Sub 909, and calculated separate components for each class of customers to include in its proposed fuel and fuel-related cost factors to recover these costs as required by G.S. 62-133(a2).

The Public Staff testimony recommended approval of DEC's requested fuel and fuel-related cost factors and no party submitted any evidence to the contrary. Based upon the evidence, the Commission concluded that the adjusted test period fuel and fuel-related cost of $1,901,733,000 and fuel and fuel-related cost factors of 2.3941¢ per kWh, 2.3931¢ per kWh, and 2.3926¢ per kWh, for the residential, general service/lighting, and industrial customer class, respectively, were reasonable and appropriate for use in this proceeding.

As revised in its supplemental testimony, DEC submitted that it had over-recovered its North Carolina retail fuel and fuel-related costs during the 12 months ending April 30, 2011 by amounts of $1,946,000, $4,684,000, and $3,638,000 for the residential, general service/lighting, and industrial classes, respectively. The associated interest, calculated at a rate of 10% per annum, on these under-recovered amounts was $260,000, $625,000, and $485,000, respectively. To calculate the appropriate EMF decrement rate riders, the over-recovered fuel and fuel-related costs plus interest was divided by the adjusted North Carolina retail kWh sales for each customer class to derive EMF decrement rate riders, including interest, equal to 0.0105¢ per kWh for the residential customer class, 0.0244¢ per kWh for the general service/lighting customer class, and 0.0343¢ per kWh for the industrial customer class. The Public Staff recommended approval of DEC's proposed EMF decrement riders and no party submitted any evidence to the contrary. Therefore, in its Order, the Commission required DEC to implement these in its Order, the Commission required DEC to implement these EMF decrement riders in its rates to refund the over-recovered fuel and fuel-related costs, plus associated interest. The Commission also found that DEC's fuel and reagent procurement and power purchasing practices were reasonable and prudent during the test period.

Accordingly, the Commission found that the total or net fuel and fuel-related cost factors to be billed to DEC's North Carolina retail customers during the 12-month billing period beginning September 1, 2011, were 2.3836¢ per kWh, 2.3687¢ per kWh, and 2.3583¢ per kWh, for the residential, general service/lighting, and industrial customer classes, respectively. The result of the Commission Order in this fuel and fuel-related charge adjustment proceeding for DEC was an increase of approximately $231,755,000 in revenue on an annual basis. The associated rate increases were approximately

$4.55 for the residential class, $4.19 for the general service/lighting class, and $3.79 for the industrial class, for each 1,000 kWh of usage per month.

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2. DEP – Docket No. E-2, Sub 1001

This fuel and fuel-related charge adjustment proceeding for DEP employed a 12-month test period ending March 31. 2011. DEP filed its Application and supporting testimony and exhibits on June 3, 2011. The evidentiary hearing was held on September 27, 2011 and the Commission issued its Order on November 14, 2011.

In DEP's pre-filed testimony, DEP submitted that its total system forecasted fuel and fuel-related cost for the period that the rates established in this proceeding would be in effect, December 1, 2011 through November 30, 2012, equaled $1,750,374,362. The nuclear capacity factor used in forecasting this amount of fuel and fuel-related cost was 92.36%. DEP's actual nuclear capacity factor during the test year was 84.81%. In comparison, the most recent NERC five year national average (2005-2009) capacity factor, appropriately weighted for size and type of nuclear units similar to DEP's nuclear units, equaled 90.45%. DEP then allocated the total system forecasted cost to the North Carolina retail jurisdiction. The total amount allocated to the North Carolina retail jurisdiction was $1,170,193,473. This amount included $62,980,053 of non-capacity purchased power costs that were allocated to North Carolina retail based upon energy usage in 2010. The total North Carolina retail amount also included $52,637,754 for the capacity cost of purchases from qualifying cogeneration and small power production facilities and the cost of purchases from renewable energy facilities that were allocated based upon peak demand in 2010. Finally, the total amount allocated to the North Carolina retail jurisdiction included an amount of $1,054,575,666 for all other types of fuel and fuel-related costs. To calculate the prospective fuel and fuel-related cost factors that it originally proposed, DEP used the $62,980,053 and $52,637,754 amounts to calculate specific components for each customer class as required by G.S. 62-133.2(a2) and spread the $1,054,575,666 amount uniformly among the customer classes.

In supplemental testimony filed on August 26, 2011 to update its under-recovery of fuel and fuel-related cost, DEP also testified that the total North Carolina retail under-recovery appropriate for the purpose of establishing the EMF riders in this proceeding was $40,980,903 including interest. This total amount of under-recovery consisted of: (1) an under-recovery of $35,369,076 that was incurred during May through July of 2010 and deferred for recovery from the Company's previous fuel charge adjustment proceeding, Docket No. E-2, Sub 976, until this proceeding; (2) an over-recovery of $29,093,110 that occurred from August 1, 2010 through April 30, 2011; (3) an under-recovery of $33,764,661 that was incurred during May through July 2011; and (4) an interest cost of $940,275. In addition to the amounts described above, during May through July of 2011, DEP also under-recovered $15,745,241 of fuel and fuel-related cost attributable to non-capacity purchased power and the capacity cost of purchases from qualifying cogeneration and renewables.

However, DEP did not seek recovery of the $15,745,241 amount in this proceeding due to the 2% cap imposed on these types of fuel and fuel-related costs in G.S. 62-133.2(a2). DEP submitted that it would seek to recover the $15,745,241 in its next annual fuel and fuel-related charge adjustment proceeding. DEP then calculated separate EMF increment riders and requested Commission approval to implement its proposed riders in order to collect the $40,980,903 of under-recovered fuel and fuel-related cost.

On September 15, 2011, the Public Staff filed testimony that presented the results of its investigation in this docket and supported a joint stipulation that was filed with its testimony. The joint stipulation was supported by all parties to this proceeding.

As noted above and as described more fully in the testimony and joint stipulation, DEP achieved a system nuclear capacity factor equal to 84.41% during the test year and DEP's two-year average nuclear capacity factor was 88.09%. The NERC five-year national average (2005-2009) nuclear capacity factor, weighted for size and type of nuclear units similar to DEP's, equaled 90.45%. Thus, the Company's failure to achieve the established performance standard in Commission Rule R8-55(k) established a rebuttable presumption that DEP imprudently incurred fuel and fuel-related costs associated with the purchase of higher cost replacement power due to nuclear plant outages. DEP's nuclear performance during the test year was greatly affected by the performance of the H.B. Robinson Nuclear Plant (Robinson). Robinson operated at a capacity factor of 57%, caused in large part by three forced outages. DEP contended that the Robinson outages were caused by equipment failures and could not have been reasonably avoided. After its investigation, the Public Staff believed that had Robinson been prudently managed, at least some of the outage time during the test year could have been avoided and at least some of the associated replacement power costs should be excluded.

The parties to the joint stipulation, including, DEP, agreed that the Company would forego recovery of $24 million on under-recovered fuel and fuel-related costs during the test year related to replacement power due to performance of DEP's nuclear plants. These parties agreed that the $24 million amount represented a fair and reasonable resolution of this issue. Therefore, the Company's North Carolina retail fuel under-recovery for purposes of the EMF was reduced from $40,980,903 to $16,904,307, including the adjustment of $24 million and an associated reduction of approximately $76,000 in interest costs. The reduced under-recovery amount of $16,904,307 including interest was used to calculate EMF riders of (0.100)¢ per kWh for the residential class; (0.024)¢ per kWh for the small general service class; 0.146¢ per kWh for the medium general service class; 0.169¢ per kWh for the large general service class; and 0.264¢ per kWh for the lighting class.

The stipulating parties also agreed that the forecasted North Carolina retail fuel and fuel-related cost amount of $1,170,193,473, as originally proposed by DEP, was appropriate for use in this proceeding. The parties further agreed that the increase in the fuel and fuel-related costs from the amounts approved in DEP's previous fuel charge adjustment proceeding should be allocated on a uniform percentage basis such that each rate class experiences the same percentage increase on average in their monthly bill, consistent with the uniform bill adjustment methodology utilized in past cases by DEP and approved by the Commission. The forecasted North Carolina retail fuel and fuel-related cost amount of $1,170,193,473 and the total North Carolina retail under-recovery amount of $40,980,903 resulted in a total increase in fuel and fuel-related costs from the amount approved in its previous fuel charge adjustment proceeding of $84,739,245, or an increase of 2.69%. Therefore, the stipulating parties developed and recommended approval of total fuel and fuel-related cost factors such that each rate class would experience an average increase of 2.69% in monthly bills. The total or net fuel and fuel-related cost factors, including the EMF riders proposed by the stipulating parties, were 3.211¢ per kWh for the residential class; 3.245¢ per kWh for the small general service class; 3.083¢ per kWh for the medium general service class; 3.015¢ per kWh for the large general service class; and 3.795¢ per kWh for the lighting class.

After carefully reviewing the joint stipulation, the Commission found that the projected and test period fuel and fuel-related costs, the stipulated fuel factors and EMF riders, and other issues addressed and resolved in the joint stipulation, were the result of negotiations among all the parties to this proceeding, were just and reasonable, and were approved for purposes of this proceeding. The Commission required that DEP implement the approved fuel and fuel-related charge adjustment in its rates effective for service rendered beginning December 1, 2011. The result of the Commission Order in this proceeding was an increase of approximately $87,667,000 in revenue on an annual basis. The associated rate increases were $2.75 for the residential class; $2.96 for the small general service class; $2.11 for the medium general service class; $1.76 for the large general service class; and $5.96 for the lighting class, for each 1,000 kWh of usage per month.

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3. <u>DNCP – Docket No. E-22, Sub 474</u>

This fuel and fuel-related charge adjustment proceeding for DNCP utilized a test period consisting of the 12-month period ending June 30, 2011. The Company filed its Application with supporting pre-filed testimony and exhibits on August 25, 2011. The evidentiary hearing was held on November 9, 2011 and the Commission issued its Order on December 13, 2011.

In its Application and testimony, DNCP proposed a prospective and aggregate or average fuel and fuel-related cost factor of 2.766¢ per kWh. The requested fuel and fuel-related cost factor was calculated using an adjusted test period system fuel cost of $2,222,314,077 divided by the adjusted test period system sales of 80,344,216,717 kWh. The Company's adjusted test period system fuel expense and prospective fuel and fuel-related cost factor was based, in part, on a 93.62% nuclear capacity factor, which was the projected nuclear capacity factor for the calendar year 2012 and during the period that the rates established in this proceeding would be in effect. The

Company’s actual nuclear capacity factor during the test year was 85.9%. In comparison, the most recent NERC five-year national average nuclear capacity factor (2006-2010) was 90.21%. Normalization adjustments were also made to test period generation and sales for weather, customer growth, and usage. During the test year, DNCP purchased power from suppliers, primarily though the markets administered by PJM Interconnection, LLC (PJM), a regional transmission organization, that did not provide DNCP with the actual fuel costs associated with such purchases. Consistent with the terms of a stipulation entered by several parties and approved by the Commission in DNCP’s previous fuel charge adjustment proceeding, Docket No. E-22, Sub 461, and applicable to this proceeding, DNCP used 85% of the energy portion of such purchases as the fuel cost. In addition, as noted above, the prospective 2.766¢ per kWh fuel and fuel-related cost factor was an aggregate or average fuel factor for the NC retail jurisdiction. The approved stipulation in Docket No. E-22, Sub 461 also provided that the fuel factor should be differentiated by customer class, based on the voltage level at which service is taken, in subsequent fuel charge adjustment proceedings unless changed in DNCP’s next general rate case. Therefore, DNCP calculated and requested approval of voltage-differentiated fuel and fuel-related cost factors for seven different customer classes that ranged from 2.798¢ per kWh for the residential class to 2.690¢ per kWh for the class containing the largest industrial customer.

DNCP also submitted that it under-recovered its test year fuel and fuel-related cost by $13,663,203. The Company calculated and requested Commission approval of EMF increments for each of the seven customer classes on a voltage-differentiated basis that ranged from 0.331¢ per kWh to 0.323¢ per kWh to collect the under-recovered fuel and fuel-related cost of $13,663,203. The EMF increments were determined by dividing the under-recovered fuel and fuel-related cost by the adjusted North Carolina test year sales and applying a class expansion factor to adjust for voltage.

Finally, DNCP also submitted a study in this proceeding showing the impact of the Company’s integration into PJM on its North Carolina retail fuel and fuel-related cost during the test year (the PJM study). In Docket No. E-22, Sub 418, the Commission allowed the Company to join PJM by Order dated April 19, 2005 (the PJM Order), subject to several conditions. The Commission included such conditions to ensure that DNCP’s ratepayers are held harmless from any adverse effects of joining PJM, including higher fuel charge adjustments. Therefore, the purpose of the PJM study is to demonstrate that the Company has complied with the relevant conditions contained in the PJM order. The PJM study submitted by the Company in this proceeding compared the Company’s total energy costs and fuel charge adjustment costs associated with operating in PJM versus the hypothetical case of the Company operating as a stand-alone entity during the test period. The Company testified that the results of this study showed that the Company’s purchase of economy energy from the PJM market was economical and beneficial compared to how the Company would have operated as a stand-alone entity and that the Company has been able to purchase and import significantly more energy from the PJM market than it was historically able to do as an independent balancing authority.

Two intervenors filed testimony raising issues of prudencey with respect to the Company's test year fuel and fuel-related cost and under-recovery. In its testimony, the Public Staff agreed with the Company's prospective fuel and fuel-related costs and factors. However, the Public Staff noted that the Company's nuclear capacity factor during the test year and the Company's two-year average nuclear capacity factor were less than the NERC five-year national average nuclear capacity factor, thereby raising the rebuttable presumption that DNCP incurred higher fuel and fuel-related costs imprudently. After conducting its investigation of the Company's nuclear plant outages during the test year, the Public Staff concluded that three outages resulted from conditions that the Company should have recognized through prudent management and taken steps to remediate during prior scheduled outages to avoid forced outages and the need to purchase more expensive replacement power. As a result, the Public Staff initially recommended an adjustment of approximately $1.1 million to the Company's test year fuel and fuel-related costs and proposed under-recovery and EMF riders. Another intervenor, representing DNCP's largest industrial customer, testified that DNCP should have used financial hedges in addition to physical hedges to restrain the rate of increase in DNCP's outlays of coal, that DNCP's rail transportation contracts limit the sources for the economic purchase of coal, and that DNCP purchased imported coal at higher prices than it could have purchased domestic coal. As a result, this intervenor recommended that the Commission disallow approximately $3.7 million of DNCP's test year fuel cost and under-recovery. DNCP filed rebuttal testimony in which it disagreed with both the Public Staff and the other intervenor with respect to the prudency of its test year fuel and fuel-related cost.

However, on the day of the hearing, DNCP, the Public Staff and the other intervenor filed a stipulation wherein they agreed to resolve all issues they had identified by reducing the test year fuel and fuel-related cost under-recovery of $13,663,203 by $825,000 to equal $12,838,203 and to reduce the EMF riders. Accordingly, the EMF riders were recalculated to reflect the agreed-upon under-recovery of $12,838,203. The revised EMF increment riders for the seven customer classes on a voltage-differentiated ranged from 0.311¢ per kWh for the residential class to 0.303¢ per kWh for the class containing the largest industrial customer.

In its Order, the Commission approved the prospective fuel and fuel-related cost factors, as well as the EMF increment rate riders, recommended by the parties to the stipulation and required DNCP to implement the new riders effective on January 1, 2012. The Commission also found that the Company's fuel procurement and purchasing practices during the test period were reasonable and prudent. In addition, the Commission found that the PJM study submitted by DNCP to demonstrate that it had complied with the conditions of the PJM was reasonable for use in this proceeding and that no adjustments to the Company's fuel and fuel-related costs were necessary.

The result of the Commission's decision and Order in this proceeding was an increase of approximately $36,121,985 in revenue on an annual basis and a net rate increase of approximately $8.78 for a residential customer using 1,000 kWh per month during calendar year 2012.

4. DEC – Docket E-7, Sub 1002

DEC's most recent fuel and fuel-related charge adjustment proceeding employed a 12-month test period that consisted of the calendar year 2011. DEC filed the Application and supporting pre-filed testimony with exhibits on March 7, 2012. The Commission held the evidentiary hearing on June 12, 2012 and issued its Order on August 16, 2012.

On May 23, 2012, DEC filed supplemental testimony to support updates and corrections to its original filing that reduced its proposed fuel and fuel-related cost factors and EMF riders. As revised, DEC submitted that its adjusted test period system fuel and fuel-related cost was $1,818,191,000. This amount of fuel cost was based, in part, upon a normalized system nuclear capacity factor of 91.87%. DEC recommended using the 91.87% nuclear capacity factor in this proceeding based upon the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. During the test year, DEC achieved a system nuclear capacity factor of 92.95%. In comparison, the most recent NERC five-year (2006-2010) national average capacity factor for pressurized water reactors similar in size to DEC's was 90.02%. Normalization adjustments were also made to test period data for weather, customer growth, line losses, and unit fuel prices.

The adjusted test period system fuel and fuel-related cost amount of $1,818,191,000 also included $4,548.000 of renewable purchased power capacity costs and $161,066,000 of noncapacity purchased power costs. In this proceeding, DEC allocated $3,311,000 of the total renewable purchased power costs and $109,166,000 of the total noncapacity purchased power costs to the North Carolina retail jurisdiction and demonstrated that the aggregate annual increase in such costs did not exceed two percent of its total North Carolina retail jurisdictional revenue in 2011. DEC then allocated the North Carolina retail portions of the renewable energy purchased power capacity costs based upon the production plant allocation factors from a recent cost of service study and allocated the noncapacity purchased power costs based upon projected energy usage, or MWH sales, as required by the Commission Order dated December 7, 2009 in DEC's general rate case, Docket No. E-7, Sub 909. DEC then calculated separate components for each class of customers to include in its proposed fuel and fuel-related cost factors to recover these allocated costs as required by G.S. 62-133.2(a2).

In its supplemental testimony, DEC also submitted that it under-recovered its North Carolina retail fuel and fuel-related cost during the period May 1, 2011 through December 2011 by amounts of $7,540,000, $7,081,000, and $3,867,000 for the residential, general service/lighting, and industrial customer classes, respectively. To calculate the appropriate EMF increment rate riders, the under-recovered fuel and fuel-related costs for each customer class was divided by the adjusted North Carolina retail kWh sales for each customer class and DEC proposed EMF increments equal to 0.0360¢ per kWh for the residential customer class, 0.0323¢ per kWh for the general service/lighting customer class, and 0.0318¢ per kWh for the industrial customer class. DEC testified that its fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

Prior to the enactment of Senate Bill 3, G.S. 62-133.2(a) required the Commission to apply a "uniform increment or decrement" to electric rates for the recovery of fuel costs. In other words, all customers in all classes paid the same fuel rider for each kWh consumed. However, Section 5 of Senate Bill 3 removed the word "uniform" from the statute.

In this proceeding, for the first time, DEC developed and proposed total or net fuel and fuel-related cost factors, including EMF riders, for each rate class such that each rate class would experience the same percentage change in its average monthly bill. DEC noted in its testimony that the use of this uniform bill adjustment methodology had previously been approved by the Commission in DEP's 2008-2010 fuel and fuel-related charge adjustment proceedings. Further, DEC stated that the Company had committed to its larger customers to propose recovery of its fuel and fuel-related cost using this methodology and agreed with the belief of its larger customers that this methodology aids in load retention, to the benefit of all customers, especially in the current economic conditions with continuing high unemployment. DEC demonstrated that its adjusted test period North Carolina retail fuel and fuel-related cost of $1,232,542,000 and the total North Carolina retail under-recovery of $18,488,000 resulted in a total decrease in its fuel and fuel-related cost from the amounts approved in its previous fuel charge adjustment proceeding Docket No. E-7, Sub 982, equal to $54,020,000, or a uniform 1.20% average rate decrease for all customer classes. Therefore, DEC calculated total or net fuel and fuel-related cost factors such that each rate class would experience a decrease of 1.20% in average monthly bills. The total or net fuel and fuel-related cost factors, including the EMF increment rate riders, proposed by DEC were 2.2584¢ per kWh for the residential class, 2.2786¢ per kWh for the general service/lighting class, and 2.2912¢ per kWh for the industrial class.

After conducting its investigation, the Public Staff filed testimony on May 24, 2012 and recommended approval of DEC's proposed fuel and fuel-related cost factors and EMF riders. No other party filed testimony and all parties to this proceeding agreed to waive cross-examination of the DEC and Public Staff witnesses. These witnesses were excused from appearance at the hearing and their pre-filed testimony and exhibits were received into evidence.

In a post-hearing brief, one party to this proceeding recommended that the Commission encourage DEC to incorporate a natural gas hedging plan into its natural gas practices within the next year. In its brief, this party stated that implementation of a hedging strategy while prices were at historic lows made good sense from the viewpoint of continued affordability and fuel diversity. Further, this party contended that more gas-fired electricity production, the increasing potential for exports of liquified natural gas, and the use of natural gas to meet more transportation needs, all combined to foretell rising natural gas prices. While not challenging the reasonableness and prudency of the Company's natural gas procurement costs in this docket, and further, acknowledging that relatively low natural gas prices had caused a debate about whether natural gas hedging programs were worthwhile, this party stated that any decision by the Company not to institute a hedging program in the near term would subject the Company's natural gas procurements to challenge, particularly if gas prices increase in the future. In its Order, the Commission declined to encourage the Company to incorporate a natural gas hedging plan into its procurement practices within the next year. The Commission noted that a Company witness testified that the Company was continuing to evaluate the feasibility of a hedging program. The Commission stated that it believed it was more appropriate to allow the Company management to decide whether, how, and when to implement natural gas hedging. The Commission noted that, in future proceedings, parties could take issues with respect to such decisions, the Company could defend the prudency of its decisions, and the Commission would fairly decide any such issues based on the evidence in future proceedings.

In its Order, the Commission found and concluded that the total or net fuel and fuel-related cost factors, including the EMF increment riders, proposed by DEC and recommended by the Public Staff were just and reasonable and required that these rates be billed to its NC retail customers during the 12-month billing period beginning September 1, 2012. The result of the Commission decisions and Order in this fuel and fuel-related charge adjustment proceeding was a decrease of approximately $55,903,000, on an annual basis. The associated rate decreases were approximately $1.30 for the residential class, $0.93 for the general service/lighting class, and $0.69 for the industrial class, for each 1,000 kWh of usage per month.

5. <u>DEP – Docket No. E-2, Sub 1018</u>

This fuel and fuel-related charge adjustment proceeding for DEP utilized a 12-month test period ending March 31, 2012. DEP filed its Application and supporting testimony with exhibits on June 4, 2012. The evidentiary hearing was held on September 18, 2012 and the Commission issued its Order on November 16, 2012.

In the pre-filed testimony and exhibits of DEP in this proceeding, DEP submitted that its total system forecasted fuel and fuel-related cost for the period that the rates established in this proceeding would be in effect equaled $1,715,659,875. The nuclear capacity factor used in forecasting this amount of fuel and fuel-related cost equaled 93.44%. DEP's actual nuclear capacity factor for the test year was 89.78%. In comparison, the most recent NERC five-year national average (2006-2010) capacity factor, weighted for size and type of units similar to DEP's, equaled 90.12%. DEP then allocated the total system forecasted cost to the North Carolina retail jurisdiction. The total amount allocated to the North Carolina retail jurisdiction was $1,121,928,712. This total amount included $90,281,593 of non-capacity purchased power costs that were allocated to North Carolina retail based upon energy usage in 2011. The total North Carolina retail amount also included $68,236,190 for the capacity cost of purchases from qualifying cogeneration and small power production facilities and the fuel and fuel-related cost of purchases from renewable energy facilities that were allocated based upon peak demand during 2011. DEP also used the $90,281,593 and $68,236,190 amounts to calculate specific components in its proposed fuel and fuel-related cost factors for each customer class as required by G.S. 62-133.2(a2) and demonstrated that the aggregate increase in such costs did not exceed two percent of its North Carolina retail revenue in 2011. Finally, the total amount allocated to North Carolina retail included an amount of $1,481,272,202 for all types of fuel and fuel-related costs.

DEP also submitted that the total North Carolina retail fuel and fuel-related under-recovery for purposes of this proceeding was $11,983,511. This total amount of under-recovery reflected on over-recovery of $3,913,225 for the period August 1, 2011 through April 30, 2012, a $15,745,241 under-recovery for May through July 2011 costs that were deferred from the previous fuel and fuel-related charge adjustment proceeding, Docket No. E-2, Sub 1001, to this proceeding, and $151,495 of interest cost associated with prior under-recovered fuel costs as authorized by the Commission in Docket No. E-2, Sub 929. DEP developed and proposed different EMF riders for each rate class to recover the total North Carolina retail fuel and fuel-related cost under-recovery of $11,983,511.

DEP also developed and proposed total fuel and fuel-related cost factors, including the EMF riders, for each rate class such that each rate class would experience the same percentage change in its average monthly bill, consistent with the methodology utilized in past cases pursuant to a settlement agreement approved by the Commission in Docket No. E-2, Sub 929. DEP demonstrated that its forecasted total North Carolina retail fuel and fuel-related cost and the total North Carolina retail under-recovery of $11,983,511 resulted in a projected decrease in its fuel and fuel-related cost from the amounts approved by the Commission in Docket No. E-2, Sub 1001 equal to $39,751,881, or a decrease of 1.23%. Therefore, DEP developed net or total fuel and fuel-related cost factors such that each rate class would experience a 1.23% decrease in average monthly bills. The net or total fuel and fuel-related cost factors, including the EMF riders also proposed by DEP, were 3.084¢ per kWh for the residential class, 3.109¢ per kWh for the small general service class, 2.986¢ per kWh for the medium general service class, 2.936¢ per kWh for the large general service class, and 3.523¢ per kWh for the lighting class.

On September 11, 2012, the Public Staff filed testimony that presented the results of its investigation in this docket and supported a joint stipulation that was filed on the same date. The joint stipulation was entered by DEP and the Public Staff (the stipulating parties) and comprehensively resolved all issues in this proceeding between them. Of the other three parties who intervened in this proceeding, two of those parties filed statements either supporting or not opposing the joint stipulation and the remaining party did not express a position regarding the joint stipulation.

In the testimony and joint stipulation, it was noted that DEP achieved a nuclear capacity factor of 89.78% in the test years and DEP's two-year average nuclear capacity factor was 87.29%. In comparison, the NERC five year national average (2006-2010) capacity factor, weighted for size and type of nuclear units similar to DEP's equaled 90.12%. Thus, the Company's failure to achieve the established performance standard created the rebuttable presumption that DEP imprudently incurred increased fuel costs associated with replacement power. DEP's nuclear performance during the test year was affected by the performance at Robinson and Brunswick Nuclear Plant (BNP) Unit 2. Robinson operated at a capacity factor of 80% during the test year, caused in part by three forced outages and an extended refueling outage. BNP Unit 2 operated at a capacity factor of 86%, caused by a refueling outage, two maintenance outages, and the extension of one of the maintenance outages. As described in more detail in the testimony of the Public Staff, after extensive investigation, the Public Staff believed that had Robinson and BNP Unit 2 been prudently managed, at least some of the outage time during the test year could have been avoided and at least some of the replacement power costs should be excluded. DEP disagreed with the Public Staff's position.

However, DEP and the Public Staff reached agreement in the joint stipulation that DEP would forego recovery of $6.5 million of replacement power fuel cost incurred during the test year due to the performance of the Company's nuclear plants. The stipulating parties agreed that the $6.5 million amount represented a fair and reasonable resolution to the nuclear performance issue and the portion of test year fuel costs that should not be recovered from ratepayers. Thus, the Company's North Carolina retail fuel and fuel-related under-recovery for purposes of the EMF was reduced from $11,983,511 to $5,483,511. The reduced under-recovery amount of $5,483,511 including interest was used to calculate EMF riders of 0.033¢ per kWh for the residential class, 0.066¢ per kWh for the small general service class, 0.036¢ per kWh for the medium general service class, (0.046)¢ per kWh for the large general service class, and (0.214)¢ per kWh for the lighting class.

The stipulating parties also agreed that the forecasted North Carolina retail fuel and fuel-related cost amount of $1,121,928,712 as originally proposed by DEP was appropriate for use in this proceeding. Those parties further agreed that the decrease in the amounts of fuel and fuel-related costs from the amounts approved by the Commission in Docket No. E-2, Sub 1001 should be allocated between the rate classes on a uniform percentage basis. This total decrease equaled $46,316,412, or a decrease of 1.43%. The total or net fuel and fuel-related cost factors, including the EMF riders proposed by the stipulating parties were 3.063¢ per kWh for the residential class, 3.086¢ per kWh for the small general service class, 2.971¢ per kWh for the medium general service class, 2.923¢ per kWh for the large general service class, and 3.478¢ per kWh for the lighting class.

After carefully reviewing the joint stipulation, the Commission found that the test period and projected fuel cost, the stipulated fuel and fuel-related cost factors and EMF riders, and other issues addressed and resolved in the joint stipulation were the result of negotiations between the Company and the Public Staff and were not opposed by any party. Therefore, based upon the evidence, the Commission found and concluded that the terms of the joint stipulation were fair and reasonable for the purposes of this proceeding. The Commission required that DEP implement the approved fuel and fuel-related charge adjustment in its rates effective for service rendered beginning on December 1, 2012. The result of the Commission's Order in this proceeding was a decrease of approximately $47,916,834 on an annual basis. The associated rate decreases were $1.54 for the residential class, $1.65 for the small general service class, $1.16 for the medium general service class, $0.96 for the large general service class, and $3.28 for the lighting class, for each 1,000 kWh of usage per month.
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6. DNCP - Docket No. E-22, Sub 485

DNCP's most recent fuel and fuel-related charge adjustment proceeding utilized a test period consisting of the 12-months ending June 30, 2012. The Company filed its Application and supporting pre-filed direct testimony with supporting exhibits on August 10, 2012. The Commission held the evidentiary hearing on November 20, 2012 and issued its Order on December 21, 2012.

Earlier that year, on March 30, 2012, DNCP filed an Application for a general rate increase in Docket No. E-22, Sub 479. In that proceeding, DNCP requested that the Commission establish a new aggregate or average base fuel and fuel-related cost factor equal to 2.476¢ per kWh. This proposed base fuel and fuel-related cost factor was calculated by dividing the adjusted test period system fuel and fuel-related cost of $1,987,367,277 by the adjusted system sales of 80,251,289,293 kWh. The Company's adjusted fuel and fuel-related cost was based, in part, on a 94.8% nuclear capacity factor, which was the expected nuclear capacity factor during the twelve months beginning January 1, 2013, the period that the new rates established in the fuel charge adjustment proceeding would be in effect. During the test year, DNCP's nuclear capacity factor was 81.8%. In comparison, the most recent NERC five-year national average nuclear capacity factor (2006-2010) was 89.9%. However, as described in the testimony of both the Company and the Public Staff, the North Anna Station experienced an earthquake on August 23, 2011, of a magnitude greater than the original design basis of those units, and an extended outage was necessary in order to perform and document inspection to ensure any damage was identified and corrected. In addition, during the test year, DNCP purchased power from suppliers, primarily PJM, that did not provide DNCP with the actual fuel cost associated with such purchases. In a previous fuel charge adjustment proceeding for DNCP, Docket No. E-22, Sub 461, parties to that proceeding entered into a stipulation that was approved by the Commission wherein it was established that 85% of the reasonable and prudent energy costs of such purchases would be recovered as a fuel and fuel-related cost and the remaining 15% would be recovered in non-fuel base rates until the earlier of the

Company's next general rate case or the 2014 fuel charge adjustment proceeding. In this general rate case proceeding, the Company, proposed to increase the 85% to 90%. Therefore, DNCP also included 90% of the energy cost of such purchases in its adjusted test period system fuel and fuel-related cost for the purpose of determining the base fuel factor in this general rate case. DNCP also recommended that the base fuel and fuel-related cost factors should be voltage-differentiated for seven customer classes.

In the fuel charge adjustment proceeding, DNCP noted that the prospective fuel and fuel-related cost factor established in this proceeding would be equal to the new base fuel factor established by the Commission in its pending general rate case. DNCP also testified that it had over-recovered its North Carolina retail fuel and fuel-related costs during the test period by $1,226,145, including an interest amount of $159,932 calculated at a rate of 10% per annum. The over-recovery of its test period fuel costs included 90% of the energy cost of purchases from suppliers that did not provide DNCP with the actual fuel cost of such purchases, consistent with the Company's proposal for establishing new base fuel and fuel-related cost factors in its pending general rate case proceeding. DNCP then calculated and proposed voltage-differentiated EMF riders for seven customer classes by dividing the over-recovery by the adjusted test period kWh sales for each of the seven customer classes.

In its testimony filed in both the fuel charge adjustment proceeding and in the pending general rate case proceeding for DNCP, the Public Staff recommended that appropriate fuel-to-energy cost of such purchases should continue to be 85%. Accordingly, the Public Staff recalculated and recommended lower base fuel and fuel-related cost factors, on a voltage-differentiated basis, and increased the portion of the energy cost included in non-fuel base rates from 10% to 15% in the general rate case. In its testimony, filed in the fuel charge adjustment proceeding, the Public Staff recommended increasing the amount of the over-recovery from $1,226,145, as proposed by the Company, to $3,637,535, including an interest amount of $474,461, and proposed voltage-differentiated EMF decrement riders based on an over-recovery of $3,637,535.

The Company also submitted a study in the fuel charge adjustment proceeding to demonstrate that it had complied with the conditions contained in the Commission's PJM Order to ensure that DNCP's ratepayers were held harmless from any adverse effects of joining PJM, including higher fuel charge adjustments.

In a stipulation filed on November 13, 2012, in both the fuel charge adjustment proceeding and in the pending general rate case proceeding, DNCP and the Public Staff stated that the only disputed issue between these two parties related to fuel cost was the appropriate fuel-to-energy cost percentage to use as a proxy for the actual fuel costs associated with purchases for which actual fuel costs are not available to DNCP. While these parties did not agree on the appropriate methodology that should be used as the basis of such a determination, it was agreed that an 85% fuel-to-energy cost percentage would be used in these proceedings for such purchases and would remain in effect until the earlier of DNCP's next general rate case or the fuel charge adjustment proceeding to be held in 2015. Incorporating this agreement, these parties further recommended a new aggregate or average base fuel factor of 2.427¢ per kWh and revised EMF decrement riders based on an over-recovery equal to $3,637,535 including interest, on a voltage-differentiated basis.

In its Order, the Commission cited that it had established a new aggregate or average base fuel and fuel-related factor equal to 2.427¢ per kWh and voltage-differentiated base fuel and fuel-related cost factors for seven customer classes ranging from 2.455¢ per kWh for the residential customer class to 2.360¢ per kWh for the customer class containing the largest industrial customer by separate Order dated December 21, 2012 in DNCP's general rate case. Consistent with the recommendations of the stipulating parties, the Commission found that DNCP over-recovered its North Carolina retail fuel and fuel-related cost by $3,637,535, including interest, during the test year and required the Company to implement voltage-differentiated EMF decrement riders ranging from 0.89¢ per kWh for the residential class to 0.85¢ per kWh for the class containing the largest industrial customer for the 12-month period beginning January 1, 2013 in order to refund the over-recovered fuel costs. The Commission also found that DNCP's fuel procurement and purchasing practices were reasonable and prudent during the test period and that the Company's PJM study was reasonable for use in this proceeding and that no adjustment in DNCP's fuel and fuel-related costs were necessary to comply with the PJM Order.

The result of the Commission's decision in this proceeding was a decrease of $16,995,611 in revenue on an annual basis. The rate decrease was approximately $4.13 for a residential customer using 1,000 kWh per month.

SUMMARY TABLE OF SIX FUEL CHARGE ADJUSTMENT PROCEEDINGS

Company and Docket No.	Date of Order	Nuclear Capacity Factor Achieved in Test Year	Approved Fuel Factor[2]	EMF Increment or (Decrement)[2] Including Interest	Total Increase/(Decrease) in Annual Revenue and in Residential Rates per 1000 kWh
1. DEC E-7, Sub 982	8/9/11	95.88%	2.3941¢	(0.0105¢)	$231.8 million $4.55
2. DEP E-2, Sub 1001	11/14/11	84.41%	3.311¢	0.100¢	$87.7 million $2.75
3. DNCP E-22, Sub 474	12/13/11	85.9%	2.798¢	0.311¢	$36.1 million $8.78
4. DEC E-7, Sub 1002	8/16/12	92.95%	2.2224¢	0.0360¢	($55.9 million) ($1.30)
5. DEP E-2, Sub 1018	11/16/12	89.78%	3.030¢	(0.033¢)	($47.9 million) ($1.54)
6. DNCP E-22, Sub 485	12/21/12	81.8%	2.455¢	(0.089¢)	($17.0 million) ($4.13)

[2] Amounts shown are in cents per kWh for residential customers, excluding gross receipts tax and the regulatory fee.
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Rule R8-55. Annual hearings to review changes in the cost of fuel and fuel-related costs.

(a) As used in this rule, “cost of fuel and fuel-related costs” means all of the following:

(1) The cost of fuel burned.

(2) The cost of fuel transportation.

(3) The cost of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(4) The total delivered noncapacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility that are subject to economic dispatch or economic curtailment.

(5) The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. 796, that are subject to economic dispatch by the electric public utility.

(6) Except for those costs recovered pursuant to G.S. 62-133.7(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 or to comply with any federal mandate that is similar to the requirements of subsections (b), (d), (e) and (f) of G.S. 62-133.7.

(7) All costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

(8) The fuel cost component of other purchased power.

Cost of fuel and fuel-related costs shall be adjusted for (a) any net gains or losses resulting from any sales by the electric public utility of fuel and other fuel-related costs components and (b) any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(b) For each electric public utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.2(b) in order to review changes in the electric public utility’s cost of fuel and fuel-related costs. The annual cost of fuel and fuel-related cost adjustment hearing for Duke Energy Carolinas, LLC, will be scheduled for the first Tuesday of June each year; for Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., the annual hearing will be scheduled for the third Tuesday of September each year; and for Virginia Electric and Power

Company, d/b/a Dominion North Carolina Power, the annual hearing will be scheduled for the second Tuesday of November each year.

(c) The test periods for the hearings to be held pursuant to paragraph (b) above will be uniform over time. The test period for Duke Energy Carolinas, LLC will be the calendar year; for Progress Energy Carolinas, Inc., the test period will be the 12-month period ending March 31; and for Dominion North Carolina Power, the test period will be the 12-month period ending June 30.

(d) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates for changes in the cost of fuel and fuel-related costs used in providing its North Carolina customers with electricity from the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case on the basis of cost per kilowatt-hour. The increment or decrement may be different among customer classes. The general methodology and procedures to be used in establishing the cost of fuel and fuel-related costs shall be as follows:

(1) Cost of fuel and fuel-related costs will be preliminarily established utilizing the methods and procedures approved in the utility's last general rate case, except that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, adjusted to reflect unique, inherent characteristics of the utility, including, but not limited to, plants 2 years or less in age and unusual events. The national average capacity factor for nuclear production facilities shall be based on the most recent 5-year period available and shall be weighted, if appropriate, for both pressurized water reactors and boiling water reactors. The costs shall be allocated among customer classes in accordance with G.S. 62-133.2(a2), as applicable. A cost of fuel and fuel-related cost rider will then be determined based upon the difference between the cost of fuel and fuel-related costs thus established and the base cost of fuel and fuel-related cost component of the rates established in the utility's most recent general rate case. The foregoing normalization requirement assumes that the Commission finds that an abnormality having a probable impact on the utility's revenues and expenses existed during the test period.

(2) Cost of fuel and fuel-related costs will be modified as provided in G.S. 62-133.2(a3).

(3) The cost of fuel and fuel-related costs as described above will be further modified through use of an experience modification factor (EMF) rider, which may be different among customer classes. The EMF rider will reflect the difference between reasonable and prudently incurred cost of fuel and fuel-related costs and the fuel-related revenues that were actually realized during the test period under the cost of fuel and fuel-related cost components of rates then in effect. Upon request of the

electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of the cost of fuel and fuel-related costs up to thirty (30) days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual fuel and fuel-related costs adjustment hearing.

(4) The cost of fuel and fuel-related cost rider and the EMF rider as described hereinabove will be charged as an increment or decrement to the base fuel cost component of rates established in the electric public utility's previous general rate case.

(5) The EMF rider will remain in effect for a fixed 12-month period following establishment and will carry through as a rider to rates established in any intervening general rate case proceedings; provided, however, that such carry-through provision will not relieve the Commission of its responsibility to determine the reasonableness of the cost of fuel and fuel-related costs, other than that being collected through operation of the EMF rider, in any intervening general rate case proceeding.

(6) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred cost of fuel and fuel-related costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(e) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information and data in the form and detail as set forth below:

(1) Actual test period kWh sales, peak demand by customer class, fuel-related revenues, and fuel-related expenses for the utility's total system and for its North Carolina retail operations.

(2) Test period kWh sales normalized for weather, customer growth and usage. Said normalized kWh sales shall be for the utility's total system and for its North Carolina retail operations. The methodology used for such normalization shall be the same methodology adopted by the Commission, if any, in the utility's last general rate case.

(3) Adjusted test period kWh generation corresponding to normalized test period kWh usage. The methodology for such adjustment shall be the same methodology adopted by the Commission in the utility's last general rate case, including adjustment by type of generation; i.e., nuclear, fossil, hydro, pumped storage, purchased power, etc. In the event that said methodology is inconsistent with the normalization methodology set forth in paragraph (d)(1) above, additional pro forma calculations shall be presented incorporating the normalization methodology reflected in paragraph (d)(1).

(4) Cost of fuel and applicable fuel-related costs corresponding to the adjusted test period kWh generation, including a detailed

explanation showing how such cost of fuel and fuel-related costs were derived. The cost of fuel shall be based on end-of-period unit fuel prices incurred during the test period, although the Commission may consider other fuel prices if test period fuel prices are demonstrated to be nonrepresentative on an on-going basis. Unit fuel prices shall include delivered fuel prices and burned fuel expense rates as appropriate.

(5) Procurement practices and inventories for fuel burned and for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(6) The cost of fuel burned and of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions at each generating facility.

(7) Any net gains or losses resulting from any sales by the electric public utility of fuel or other fuel-related costs components.

(8) Any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(9) All costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

(10) The monthly fuel report and the monthly base load power plant performance report for the last month in the test period and any information required by Rules R8-52 and R8-53 for the test period which has not already been filed with the Commission. Further, such information for the complete 12-month test period shall be provided by the electric public utility to any intervenor upon request.

(11) All workpapers supporting the calculations, adjustments and normalizations described above.

(12) The nuclear capacity rating(s) in the last rate case and the rating(s) proposed in this proceeding. If they differ, supporting justification for the change in nuclear capacity rating(s) since the last rate case.

(13) The proposed rate design to recover the electric public utility's cost of fuel and fuel-related costs.

An electric public utility that is subject to G.S. 62-133.2(a3) is required to provide only the applicable information prescribed by subdivisions (5), (6) and (8) of this subsection.

(f) The electric public utility shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert witnesses supporting the information filed herein, and any changes in rates proposed by the electric public utility (if any), according to the following schedule: Duke Energy Carolinas, LLC, and Progress Energy Carolinas, Inc., not less than 90 days prior to the hearing; Dominion North Carolina Power, not less than 75 days prior to the hearing. Nothing in this rule shall be construed to require the electric public utility to propose a change in rates or to utilize any particular methodology to calculate any change in rates proposed by the utility in this proceeding.

(g) The electric public utility shall publish a notice for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.2(b) and setting forth the time and place of the hearing.

(h) Persons having an interest in said hearing may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(i) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(j) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(k) The burden of proof as to the correctness and reasonableness of any charge and as to whether the test year cost of fuel and fuel-related costs were reasonable and prudently incurred shall be on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation’s Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation’s Generating Availability Report, appropriately weighted for size and type of plant, or a presumption will be created that the utility incurred the increased cost of fuel and fuel-related costs resulting therefrom imprudently and that disallowance thereof is appropriate. The utility shall have the opportunity to rebut this presumption at the hearing and to prove that its test year cost of fuel and fuel-related costs were reasonable and prudently incurred. To the extent that the utility rebuts the presumption by the preponderance of the evidence, no disallowance will result.

(l) The hearing will generally be held in the Hearing Room of the Commission at its offices in Raleigh, North Carolina.

(m) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently incurred cost of fuel and fuel-related costs and cost of fuel and fuel-related costs recovered under rates in effect.

(n) If the Commission has not issued an order pursuant to G.S. 62-133.2 within 180 days after the date the electric public utility has filed any proposed changes in its rates and charges in this proceeding based solely on the cost of fuel and fuel-related costs, then the utility may place such proposed changes into effect. If such changes in the rates and charges are finally determined to be excessive, the electric public utility shall refund any excess plus interest to its customers in a manner directed by the Commission.