(e) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.1(d), 3.11 and 5.13 shall be made by DEC and PEC in Sub 986E and Sub 998E, respectively;

13.2 ***Advance Notice Filings.*** **Advance notices filed pursuant to Regulatory Conditions 3.1(c), 3.3(b), 3.7(c), 3.10(c), 4.2, 5.3, 8.8, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall state what condition and notice period are involved and whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:**

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.

*122 (b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.

(c) DEC or PEC shall serve such advance notices on each party to Docket Nos. E-7, Sub 986, and E-2, Sub 998, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.

(d) To effectuate this Regulatory Condition, DEC or PEC shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DEC or PEC objects to a discovery request, DEC or PEC and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DEC or PEC may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response within the notice period. DEC or PEC may file a reply to the response(s)

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DEC or PEC, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no order, whether procedural or substantive, has been issued, DEC, PEC, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the activity to be undertaken, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement

*123 (l) DEC, PEC, the Public Staff, or any party may move for a waiver if exigent circumstances in a particular case justify such.

SECTION XIV

COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Duke Energy, DEC, PEC, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner

14.1 *Ensuring Compliance with Regulatory Conditions and Code of Conduct.* Duke Energy, DEC, PEC, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the DEC/PEC Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 *Designation of Chief Compliance Officer.* DEC and PEC shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's and PEC's Internet Website.

14.3 *Annual Training.* DEC and PEC shall provide annual training on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 *Report of Violations.* If DEC and PEC discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DEC and PEC shall file a statement with the Commission in Docket Nos. E-7, Sub 986C, and E-2, Sub 998C, respectively, describing the circumstances leading to that violation of DEC's or PEC's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

CODE OF CONDUCT

GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF PEC, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC AND PEC

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions

*124 *Affiliate*: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of each other and DEC and PEC are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information: Nonpublic information that pertains to Electric Services provided by DEC or PEC, including but not limited to information concerning electric generation, transmission, distribution, or sales.

Customer: Any retail electric customer of DEC or PEC in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC or PEC in connection with the supplying of Electric Services to that Customer or group of Customers.

DEBS. Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, singly or in any combination.

DEC Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC and PEC, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or PEC from sources other than DEC or PEC for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity: provided, however, that (a) for each good and service supplied by DEC or PEC, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good and service supplied to DEC or PEC, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good and service supplied by DEC and PEC to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's and PEC's most recent general rate case proceedings.

*125 *JDA*: Joint Dispatch Agreement, which is the agreement as filed with the Commission on April 1, 2011, and as revised and filed on April 4, 2011, in Docket Nos. E-7, Sub 980, and E-2, Sub 995, and allowed by the Commission to be filed with the FERC, by Order dated April 4, 2011, and as further revised and filed on June 22, 2011, and allowed to be filed with the FERC by Order dated July 11, 2011, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Progress Energy.

Natural Gas Services: Natural gas sales and natural gas transportation, and other related services, including, but not limited to, metering and billing.

Nonpublic Utility Operations: All business operations engaged in by DEC or PEC involving activities (including the sales of goods or services) that are not regulated by the Commission, or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS and PESC, other than a Utility Affiliate, DEC, or PEC.

PEC: Progress Energy Carolinas, Inc., the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territory of PEC and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Personnel: An employee or other representative of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

PESC: Progress Energy Services Company and its successors, which is a service company Affiliate that provides Shared Services to PEC, DEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC or PEC, individually or in combination.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of PEC, and which became a subsidiary of Duke Energy after the close of the Merger, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC or PEC to take from DEBS or PESC pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

*126 *Utility Affiliates*: The regulated public utility operations of Duke Energy Indiana, Inc. (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), and Florida Power Corporation, d/b/a Progress Energy Florida (PEF); and the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC and PEC, to the extent such relationships, activities, and transactions affect the operations or costs of utility service experienced by the public utility operations of DEC and PEC in their respective service areas. DEC, PEC, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 998, and E-7, Sub 986. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry; or other changes that warrant modification of this Code.

DEC or PEC may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that exigent circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. *Independence and Information Sharing*

1. Separation - DEC, PEC, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable. DEC, PEC, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's and PEC's Nonpublic Utility Operations shall maintain separate records from those of DEC's and PEC's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC and PEC may provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation under the same terms and conditions that such information is provided to non-Affiliates.

(b) Except as provided in Section III.A.2.(f) below, Customer Information shall not be disclosed to any person or company, without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be obtained by means of written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC and PEC retain such authorization for verification purposes for as long as the authorization remains in effect.

*127 (c) If the Customer allows or directs DEC or PEC to provide Customer Information to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, then DEC or PEC shall ask the Customer if he, she, it would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC or PEC to provide Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Sections III.A.2.(a), 2.(b), and 2 (c) herein shall be permanently posted on DEC's and PEC's website

(e) No DEC or PEC employee who is transferred to Duke Energy or another Affiliate will be permitted to copy or otherwise compile any Customer Information for use by such entity except pursuant to written permission from the Customer, as reflected by a signed Data Disclosure Authorization. Neither DEC nor PEC shall transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity

(f) Notwithstanding the prohibitions established by this Section III.A.2, DEC and PEC may disclose Customer Information to DEBS, PESC, any other Affiliate, a Nonpublic Utility Operation or a non-affiliated third party without Customer consent, but only to the extent necessary for the Affiliate, Nonpublic Utility Operation or non-affiliated third party to provide goods or services to DEC or PEC and upon their explicit agreement to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(g) DEC and PEC shall take appropriate steps to store Customer Information in such a manner as to limit access to only those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC and PEC shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS or PESC employee may use Customer Information to market or sell any product or service to DEC's or PEC's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC or PEC.

(j) DEBS and PESC employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS or PESC that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of the Utilities.

(k) Should any inappropriate disclosure of DEC or PEC Customer Information occur at any time, DEC or PEC is required to promptly file a statement with the Commission in this docket describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

3. The disclosure of Confidential Systems Operation Information of DEC and PEC (referred to hereinafter as 'Information') shall be governed as follows:

***128** (a) Such Information shall not be disclosed by DEC or PEC to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required when disclosure to Affiliates or Nonpublic Utility Operations meets one of the following exceptions:

(i) The Information is provided to employees of DEC or PEC for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998;

(ii) The Information is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements;

(iii) A state or federal regulatory agency or court having jurisdiction over the disclosure of the Information requires the disclosure;

(iv) The Information is provided to employees of DEBS or PESC pursuant to a service agreement filed with the Commission pursuant to G.S 62-153,

(v) The Information is provided to employees of DEC's or PEC's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service;

(vi) The Information is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of Information to be disclosed;

(vii) Disclosure is otherwise essential to enable DEC or PEC to provide Electric Services to their Customers; or

(viii) Disclosure of the Information is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any Information disclosed pursuant to the exceptions in Section III. A.3(a), above, shall be disclosed only to employees that need the information for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such Information must be prohibited from acting as conduits to pass the Information to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such Information.

(c) For disclosures pursuant to exceptions (vii) and (viii) in Section III.A.3(a), above, DEC and PEC shall include in their annual affiliated transaction reports the following information:

(i) The types of Information disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed.

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process. To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, PEC, DEBS, and PESC employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and PEC.

*129 (e) Should the handling or disclosure of Market Information, Transmission Information, or other CSOI by DEBS, PESC, or another Affiliate or Nonpublic Utility Operation, or their respective employees, result in (i) a violation of DEC's or PEC's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358-Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an OASIS or other Internet website, or (iii) other public disclosure of the data, DEC or PEC shall promptly file a statement with the Commission in Commission in Docket Nos. E-7, Sub 986C, and E-2, Sub 998C, respectively, describing the circumstances leading to such violation, posting, or other this docket describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the mitigating and/or other steps taken to address the current or any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC or PEC shall promptly file a statement with the Commission in Docket Nos. E-7, Sub 986C, or E-2, Sub 998C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and PEC shall file a letter in Docket Nos. E-7, Sub 986E, and E-2, Sub 998E, with the Commission describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's and PEC's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, neither DEC nor PEC shall provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, nor to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, PEC, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC and PEC shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC and PEC shall process all similar requests for Electric Services in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, PEC, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC or PEC; provided however, that this prohibition shall not apply to employees of DEBS or PESC providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or PEC's regulated public utility operations.

6. No personnel or representatives of DEC, PEC, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. Neither DEC nor PEC shall condition or otherwise tie the provision or terms of any Electric Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC or PEC receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2 of this Code of Conduct.

C. Marketing

1. The public utility operations of DEC and PEC may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Utility Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. Neither DEC nor PEC shall otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

*130 (a) '[Duke Energy Corporation/Affiliate) is not the same company as [DEC/PEC], and [Duke Energy Corporation/ Affiliate) has separate management and separate employees';

(b) '[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission';

(c) 'Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/PEC]'; and

(d) 'A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/PEC].'

3. Nonpublic Utility Operations may not use the names or logos of DEC or PEC in any communications unless a disclaimer is included that states the following:

(a) '[Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/PEC] and is not in any way sanctioned by the North Carolina Utilities Commission';

(b) 'Purchasers of products or services from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/PEC]'; and

(c) 'A customer does not have to buy products or services from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/PEC].'

The required disclaimer must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC or PEC and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC or PEC for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. As a general guideline, with regard to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC or PEC, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's or PEC's operations or costs of utility service, the following conditions shall apply:

(a) Except as otherwise provided for in this Section III D, for untariffed goods and services provided by DEC or PEC to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC or PEC shall be set at the higher of Market Value or DEC's or PEC's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D, for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS or PESC, or a Nonpublic Utility Operation to DEC or PEC, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC or PEC shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC or PEC do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC and PEC shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's and PEC's Customers receive service at the lowest reasonable cost. For goods and services provided by DEBS and PESC to DEC, PEC, and Utility Affiliates, the transfer price charged shall be set at DEBS' and PESC's Fully Distributed Cost.

***131** (c) Tariffed goods and services provided by DEC and PEC to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services (such as time of use, manner of use, customer class, load factor, and relevant Standard Industrial Classification) under the applicable tariff.

(d) Subject to and in compliance with all conditions placed upon DEC and PEC by the Commission, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC or PEC to DEC, PEC, or the Utility Affiliates or by the Utility Affiliates to DEC or PEC, shall be transferred at the supplier's Fully Distributed Cost.

4. To the extent that DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS or PESC (or their successors), these Shared Services may be jointly provided to DEC, PEC, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC and PEC is cost beneficial on a service-by-service (*e.g.*, accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC and PEC. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual(s) filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, PEC, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of natural gas, coal, and electricity or ancillary services intended for resale), if such joint purchases result in cost savings to DEC's and PEC's Customers. DEC, PEC, Duke Indiana, Duke Kentucky, and PEF, may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's and PEC's Customers. Notwithstanding the foregoing, if any of the coal or natural gas jointly purchased by DEC, PEC, Duke Indiana, Duke Kentucky, or PEF is transferred to or utilized by another Affiliate within 12 months of the joint purchase, DEC and PEC will file a notification of such with the Commission. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's and PEC's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manuals required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC and PEC incur in assembling, compiling, preparing, or furnishing requested Customer Information or Confidential Systems Operation Information for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates shall be recovered from the requesting party pursuant to Section III.D.3 of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC or PEC in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission; provided however, that DEC and PEC are not required to provide advance notice for such transfers to each other. DEC and PEC may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC and PEC shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The State's existing requirements regarding affiliate transactions, as set forth in G.S. 62-153, shall continue to apply to all transactions between DEC, PEC, Duke Energy, and the other Affiliates.

2. The books and records of DEC, PEC, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC or PEC with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or PEC to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or PEC shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

*132 To the extent any bill issued by DEC and PEC, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes any charges to Customers for Electric Services and non-Electric Services from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for the Electric Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC and PEC shall establish complaint procedures to resolve potential complaints that arise due to the relationship of DEC and PEC with Duke Energy, its other Affiliates, and its Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC or PEC

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC or PEC shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC and PEC shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1, any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint or otherwise address questions to the Commission.

CODE OF CONDUCT

ATTACHMENT A

DEC/PEC CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/PEC's Affiliates offer products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina These products and services may be available from other competitive sources.

The Customer authorizes DEC/PEC to provide any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases [*or specify specific types of data*] to the following Affiliate(s) ___. DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations

DEC/PEC offers optional, market-based products and services that are separate from the regulated services provided by DEC/PEC. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

*133 The Customer authorizes DEC/PEC to use any data associated with the Customer account(s) residing in any DEC/PEC files, systems or databases [*or specify types of data*] for the purpose of offering and providing energy-related products or services to the Customer DEC/PEC will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

FOOTNOTES

Footnotes

1 Commissioner Lorinzo L. Joyner retired on December 31, 2011, and, therefore, did not participate in this Order

2 According to witness Hoard, the utilities have projected five-year CTA of $50 8 million to implement coal blending at three DEC generating plants.

3 *See, e.g.*, Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, 96 NCUC 183 (Docket No E-7, Sub 795, March 24, 2006); Order Approving Merger and Issuance of Securities, 90 NCUC 187 (Docket No. E-2, Sub 760, August 22, 2000), Order Approving Merger and Issuance of Securities, 89 NCUC 384 (Docket No G-5, Sub 400, December 7, 1999), Order Approving Merger and Issuance of Securities, 89 NCUC 306 (Docket No. E-22, Sub 380, October 18, 1999)

4 Although regulatory conditions were in place at that time preventing DEC from challenging the Commission's order on appeal, similar to the conditions Orangeburg challenges here, the conditions did not prohibit Orangeburg from appealing

5 Condition 2.2 is found on page 5 of the Regulatory Conditions that were attached as Appendix A and filed in corrected form on September 15, 2011 It reads as follows: 'Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, PEC, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G S 62-94(b).

End of Document

BEFORE

THE PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2011-158-E - ORDER NO. 2012-517

JULY 11, 2012

IN RE:	Application of Duke Energy Corporation and Progress Energy, Inc. on Behalf of Their Electrical Utility Subsidiaries, Duke Energy Carolinas, LLC and Progress Energy Carolinas, Inc. to Engage in a Business Combination Transaction	))))))	ORDER APPROVING JOINT DISPATCH AGREEMENT

I. INTRODUCTION

Pursuant to S.C. Code Ann. § 58-27-1300 (Supp. 2011) and S.C. Code Ann. Reg. 103-823, on April 25, 2011, Duke Energy Corporation ("Duke")[1] and Progress Energy, Inc. ("Progress")[2] (collectively referred to as "the Applicants"), on behalf of their utility subsidiaries Duke Energy Carolinas, LLC ("DEC") and Progress Energy Carolinas, Inc. ("PEC"), applied to the Public Service Commission of South Carolina ("the Commission") for approval of the merger of DEC and PEC, and approval of a joint dispatch agreement ("JDA").[3] In their Application, the Applicants explained that Duke and Progress have entered into a business combination

[1]Duke is a corporation organized and existing under the laws of the State of Delaware. Duke is the sole owner of DEC. DEC is an electric public utility organized, existing and operating under the laws of the State of North Carolina, and is authorized to generate, transmit and distribute electric power in its service territory in North Carolina and South Carolina.

[2]Progress is a corporation organized and existing under the laws of the State of North Carolina. Progress is the sole owner of PEC. PEC is an electric public utility organized, existing and operating under the laws of the State of North Carolina and is authorized to generate, transmit and distribute electric power in its service territory in North Carolina and South Carolina.

[3] This present Commission Order necessarily reflects the ruling made by the Commission on the basis of the record before it as of 11:30 a.m. on July 2, 2012, when the Commission vote on this Application was taken, and does not address any events occurring subsequent to that ruling.

agreement ("the Merger Agreement") pursuant to which Duke will acquire all of the issued and outstanding common stock of Progress in exchange for shares of Duke's common stock.[4] (Hereinafter the proposed merger of Duke and Progress shall be referred to as "the Merger".)

As part of the parties' presentation of evidence to this Commission at hearing on December 12, 2011, we heard testimony concerning the Merger of Duke Energy Corporation and Progress Energy, Incorporated. Based on the record before us, there is an absence of harm to South Carolina ratepayers as a result of the proposed Merger. Therefore, we do not have to reach the question of whether such harm, if present, would have justified jurisdiction of this Commission over the Merger to the extent necessary to address such harm to this state's ratepayers.

Under the terms of the Merger Agreement, Progress shareholders will receive 2.6125 shares of Duke common stock for each share of Progress common stock they own upon the closing of the transaction. This exchange ratio will be adjusted to 0.87083 shares of Duke stock for each Progress share, to account for a one-for-three reverse stock split to be effected by Duke in connection with the closing of the transaction, as further described in the Merger Agreement. The combined company will maintain the name of Duke Energy, with corporate headquarters in Charlotte, North Carolina. Progress will become a subsidiary of Duke, and both Progress and PEC will continue to exist as separate legal entities.

Subject to approval by the appropriate regulatory commissions, PEC and DEC plan to merge into a single legal entity at some point in the future; however, such merger will not occur until numerous aspects of the utilities' operations are addressed, including but not limited to

[4] Progress common stock owned by Duke or Progress (other than in a fiduciary capacity) will not be included in the exchange. Such stock will automatically be canceled and retired.

determination of best business practices, operating procedures, equipment specifications, uniform rate schedules, service regulations, and computer systems.

Pursuant to the JDA, PEC will transfer operational control of its generating assets to DEC. The combined DEC and PEC generating assets would then be jointly dispatched to serve the combined load of DEC and PEC in the most cost effective manner possible.

Intervenors in the proceeding included the Southern Alliance for Clean Energy, the Environmental Defense Fund, the South Carolina Coastal Conservation League (collectively "the Environmental Intervenors"), South Carolina Electric & Gas Company ("SCE&G"), Nucor Steel-South Carolina ("Nucor"), the City of Orangeburg, the South Carolina Energy Users Committee ("SCEUC"), Central Electric Power Cooperative, Inc., the Electric Cooperatives of South Carolina, Inc., and the International Brotherhood of Electrical Workers ("IBEW"). The South Carolina Office of Regulatory Staff ("ORS") was a party pursuant to S.C. Code Ann. § 58-4-10 (Supp. 2011).

By letter dated September 13, 2011, the Applicants notified the Commission that they were withdrawing their Application for approval of the merger of DEC and PEC. The Applicants stated that it was premature to be seeking such approval given that the actual merger of the two utilities would not occur for several years. ORS and the intervenors did not oppose the withdrawal of the Application for approval of the merger of PEC and DEC.

A hearing in this matter was initially scheduled to begin October 26, 2011, with the Applicants' direct testimony to be filed by September 14, 2011. On September 14, 2011, the Applicants filed the joint testimony of James E. Rogers and William D. Johnson, and the testimonies of Lynn J. Good, Dr. Joseph P. Kalt, and Alexander J. (Sasha) Weintraub.

On October 4, 2011, ORS, Central Electric Power Cooperative and the Electric Cooperatives of South Carolina, Inc. filed a joint motion to hold the hearing and procedural schedule in this matter in abeyance until the Federal Energy Regulatory Commission ("FERC") ruled upon a market power mitigation proposal that FERC required the Applicants to file as a condition of FERC merger approval. On October 10, 2011, DEC and PEC filed a response to the joint motion to hold the proceeding in abeyance. DEC and PEC did not oppose the joint motion, but requested that the Commission reschedule testimony filing dates and the hearing in this matter as soon as possible after the filing of the Applicants' mitigation proposal with FERC. The Commission granted the motion to hold the hearing and procedural schedule in abeyance.

On October 24, 2011, ORS, Central Electric Power Cooperative and the Electric Cooperatives of South Carolina, Inc. filed a joint motion to establish a new procedural schedule. By Order No. 2011-816, issued November 2, 2011, the Commission: granted the motion to establish new testimony filing dates and hearing date; rescheduled the hearing to begin December 12, 2011; required DEC and PEC to file supplemental testimony on November 10, 2011, to discuss the market power issues raised by FERC in its September 30, 2011, order conditionally approving the Merger, and explaining DEC's and PEC's market power mitigation proposal filed with FERC in response; and scheduled intervenor, rebuttal, and surrebuttal testimony to be filed November 17, 2011, November 30, 2011, and December 7, 2011, respectively.

Pursuant to Commission Order No. 2011-816, DEC and PEC filed the supplemental testimony of Alexander J. Weintraub on November 10, 2011. On November 17, 2011, the ORS filed the direct testimony of Jonathan Falk, the City of Orangeburg filed the direct testimony of John Bagwell, and the Environmental Intervenors filed the direct testimony of Richard Hahn.

DEC and PEC filed the joint rebuttal testimony of James E. Rogers and William D. Johnson and the rebuttal testimonies of Lynn J. Good, Alexander J. Weintraub, and Dr. Joseph P. Kalt on November 30, 2011. On December 8, 2011, the Environmental Intervenors and the Applicants entered into a Settlement Agreement which was submitted to this Commission for approval. Concurrently, the Environmental Intervenors withdrew the testimony of Richard Hahn. Also, on December 8, 2011, in response to the Environmental Intervenors' withdrawal of the testimony of Richard Hahn, DEC and PEC withdrew the rebuttal testimony of Lynn J. Good and filed the revised joint testimony of James E. Rogers and William D. Johnson, and the revised testimonies of Alexander J. Weintraub and Dr. Joseph P. Kalt.

The hearing on this matter commenced as scheduled on December 12, 2011. At the hearing, Len S. Anthony and Kendal C. Bowman represented PEC. Kodwo Ghartey-Tagoe and Frank R. Ellerbe, III represented DEC. Courtney D. Edwards and Nanette S. Edwards represented the ORS. Christopher R. Koon, Douglas Jennings, Jr., and John H. Tiencken represented Central Electric Power Cooperative, Inc. and the Electric Cooperatives of South Carolina, Inc. James N. Horwood and Pablo O. Nuesch represented the Department of Public Utilities of the City of Orangeburg. Gudrun Elise Thompson and J. Blanding Holman IV represented the Environmental Intervenors. Michael K. Lavanga and Robert R. Smith II represented Nucor. K. Chad Burgess represented SCE&G. Scott Elliott represented SCEUC.

On December 13, 2011, the Applicants submitted a letter to the Commission to memorialize the stipulation and commitment made by the Applicants during the hearing held December 12, 2011. The letter stated that, as a condition for Commission approval of the proposed JDA between DEC and PEC, DEC and PEC will provide the Commission a "most favored nations" commitment. Among other things, the "most favored nations" commitment guarantees this Commission and DEC's and PEC's retail customers pro rata benefits equivalent to those approved by the North Carolina Utilities Commission in its order ruling upon Duke Energy Corporation's and Progress Energy, Inc.'s Merger Application. The December 13, 2011, commitment letter is attached to this order as Appendix A.

On December 14, 2011, the FERC issued an Order in which it found the Applicants' proposed market power mitigation plan was inadequate to address the wholesale market power concerns raised in the FERC's September 30, 2011, Order. On that same date, the FERC also issued an Order dismissing the Applicants' Application for approval of the JDA without prejudice to the Applicants' right to file revised proposals.

The Commission initially scheduled the filing of proposed orders for December 20, 2011. DEC, PEC, the ORS, Central Electric Power Cooperative, Nucor Steel-South Carolina, and the Electric Cooperatives of South Carolina, Inc. filed a Joint Proposed Order. The City of Orangeburg also filed a Proposed Order.

On January 12, 2012, PEC and DEC filed with the Commission a letter containing a status report of the Merger activities before the North Carolina Utilities Commission ("NCUC") and FERC. On February 22, 2012, PEC and DEC filed with the Commission a copy of the advance notice filed with the NCUC notifying the NCUC that Progress and Duke would be filing a Revised Market Power Mitigation Plan with FERC upon the expiration of the notice period. On March 26, 2012, PEC and DEC filed with the Commission the Revised Market Power Mitigation Plan that was filed with FERC that same date. The Revised Market Power

Mitigation Plan was filed by Progress and Duke pursuant to the FERC's December 14, 2011, Order.

On May 16, 2012, PEC and DEC filed with the Commission a letter advising the Commission that PEC and DEC had made certain commitments to the ORS with regard to the Revised Market Power Mitigation Plan filed with FERC on March 26, 2012. The first commitment relates to the allocation of costs associated with interim wholesale mitigation power sales to be made by PEC and DEC for approximately 3 years following the close of the Merger. The letter described the methodology to be used to allocate costs to these sales and the calculation of a decrement rider to be filed by PEC and DEC to their retail South Carolina rates within 30 days after the Merger closes to provide their South Carolina retail customers the benefit of this allocation of costs away from retail to these wholesale sales. The second commitment relates to the permanent transmission market power mitigation element of the Revised Market Power Mitigation Plan. PEC and DEC committed not to seek recovery of any of the costs associated with certain new transmission facilities constructed to mitigate the merged company's wholesale market power from their South Carolina retail customers for a period of five years following the closing of the Merger. After five years, PEC and DEC may seek recovery of these transmission costs from their South Carolina retail customers if they can show that, absent the Merger, the transmission facilities are needed to provide adequate and reliable retail service and the construction of the facilities and incurrence of the costs would have been reasonable and prudent. The letter's third commitment was a re-affirmation of their commitment and guarantee, described during the December 12, 2011, hearing, and summarized in the utilities' December 13, 2011, letter filed with the Commission, to provide their retail

South Carolina customers pro rata benefits equivalent to those approved by the North Carolina Utilities Commission in its order ruling upon Duke's and Progress' Merger Application. The May 16, 2012, commitment letter, along with the clarifying letter of May 21, 2012 referenced below, are attached to this order as Appendix B.

On May 21, 2012, PEC and DEC filed a follow-up letter explaining that nothing that had occurred in the NCUC Merger proceeding and none of the commitments contained in the May 16, 2012, letter to the Commission alter or affect the JDA. *See* Appendix B. The May 21, 2012, letter also clarified that the costs associated with the interim wholesale market power sales would be allocated to those specific wholesale transactions and not PEC's and DEC's wholesale jurisdiction as a whole.

By Order No. 2012-425, on May 23, 2012, the Commission ordered the parties to this proceeding to file verified testimony by June 4, 2012, concerning the developments regarding the Merger occurring subsequent to the December 12, 2011, hearing. The Commission asked the parties to address, in particular, activities and filings before the NCUC and FERC. Responses to such testimony were to be filed by June 11, 2012. The Commission further ruled that it would decide on June 13, 2012, whether further hearings in this docket were required. On June 4, 2012, PEC and DEC filed the additional direct testimony of Sasha Weintraub. On June 11, 2012, the ORS, Central Electric Power Cooperative and the Electric Cooperatives of South Carolina, Inc., filed letters in support of approval of the JDA on a one year trial basis.

On June 8, 2012, FERC approved the JDA, PEC's and DEC's Joint Open Access Transmission Tariff, and the Merger of Progress and Duke, with certain conditions, and provided that certain revisions be made to the JDA. On June 12, 2012, PEC and DEC filed with the Commission a revised JDA reflecting the changes required by FERC. In the transmittal letter, PEC and DEC explained that the revisions do not impact any of the potential savings to be realized from the joint dispatch of PEC's and DEC's generation facilities, or otherwise harm South Carolina retail customers. On June 13, 2012, PEC and DEC filed the verified testimony of Sasha Weintraub, explaining the revisions to the JDA and affirming that such changes do not harm South Carolina retail customers or reduce the benefits to be derived from joint dispatch.

On June 13, 2012, by Order No. 2012-473, the Commission ordered that any responses to the revised JDA or the verified testimony of Sasha Weintraub had to be filed by June 15, 2012. The Commission further held that no further hearings were necessary and that proposed orders were to be filed on June 22, 2012. The only filing made by any party on June 15, 2012, was a filing by the ORS stating that they had no further comments. A Joint Proposed Order was filed on June 22, 2012, by DEC, PEC, the ORS, Nucor Steel-South Carolina, Central Electric Power Cooperative and the Electric Cooperatives of South Carolina, Inc. A Proposed Order was also filed on June 22, 2012, by the Intervenor, City of Orangeburg.

II. DISCUSSION

A. FERC APPROVAL OF THE MERGER AND JDA

As explained in the supplemental pre-filed testimony of Applicants' witness Weintraub, on September 30, 2011, FERC conditionally approved the Merger of Progress and Duke. However, FERC found "screen failures" with respect to the market for short-term energy during the summer and winter periods in the DEC Balancing Authority Area ("BAA") and the summer period in the PEC East BAA. A "screen failure" means that the increase in the concentration of ownership of short-term energy resulting from the Merger exceeds certain thresholds established by FERC. As a result, FERC required PEC and DEC to submit a mitigation proposal to eliminate any potential for the exercise of market power by PEC and DEC during these periods. Tr. pp. 150-152.

The Applicants submitted a market power mitigation proposal that required PEC and DEC to offer to sell for resale in their BAAs a certain amount of excess generation during these time periods. PEC would be required to offer to sell all excess generation up to 500 MWs during the summer months. DEC would be required to offer to sell excess generation up to 300 MWs during the summer months and 225 MWs during the winter months. The price at which this excess generation would be sold would be the average incremental cost of the generation plus 10%. PEC and DEC would offer this energy on a daily basis. The proposed term of the mitigation proposal was eight years. Under the proposed mitigation plan, both PEC and DEC would be allowed to cancel any sale made if PEC or DEC needed that generation to reliably meet its retail or native load firm wholesale customers' needs. Tr. pp. 152-153.

By Order issued on December 14, 2011, FERC found the Applicants' Market Power Mitigation Proposal to be inadequate and afforded the Applicants an opportunity to file a revised, more comprehensive, market power mitigation plan in order to obtain unconditional FERC approval of the Merger and JDA. In his Additional Direct Testimony filed on behalf of PEC and DEC on June 4, 2012, pursuant to the Commission's Order No. 2012-425, Mr. Weintraub explained that on March 26, 2012, in response to FERC's December 14, 2011, Order, the Applicants filed a Revised Mitigation Proposal with FERC. The Revised Mitigation Proposal had two elements: an interim mitigation component that involved the sale of capacity and energy to third party wholesale market participants; and a permanent mitigation component that involved the construction of new transmission facilities. As proposed, the interim mitigation sales would terminate once all of the new transmission facilities had been constructed and placed into service.

The interim mitigation sales were proposed in recognition of the fact that, until the permanent transmission expansion projects are placed in service, FERC's market power concerns would continue. DEC and PEC have entered into firm power sales agreements ("PSAs") with Cargill, Electricitie de France (EDF), and Morgan Stanley to effectuate the interim mitigation sales. The energy sold pursuant to the PSAs will be firm in all hours of those seasons when mitigation is required. There are no restrictions on the use of energy by the purchasers after it is purchased. Any interruption of deliveries of energy by DEC or PEC will result in the payment of liquidated damages if the contract price of power to be sold is below the market unless that interruption is excused on *force majeure* grounds.

Mr. Weintraub testified that sales under the PSAs will commence the first day after the Merger is closed. The term of each of PEC's PSAs will extend through August 31, 2014. The term of DEC's PSA will extend through February 28, 2015. These dates ensure that the interim mitigation will be in place until the permanent mitigation transmission expansion projects are expected to be completed.

Mr. Weintraub then explained that the Applicants' permanent mitigation proposal consists of the construction of seven transmission expansion projects in order to increase transmission import capability into the PEC East and DEC BAAs. The projects provide permanent structural mitigation of FERC's market power concerns. In addition to these seven projects, PEC is accelerating the in-service date of PEC's already-planned Greenville - Kinston DuPont 230 kV Line from 2017 to 2015.

According to Mr. Weintraub, these transmission expansion projects completely mitigate all market power issues in the DEC BAA, and also completely mitigate all market power issues in the PEC East BAA except for the Summer Off-Peak in the Base Case. To address this single screen failure, DEC and PEC indicated they were willing to agree to set-aside a portion of the expanded transmission capacity from the DEC BAA to the PEC East BAA. Under this proposal, only unaffiliated third parties would be permitted to reserve the set-aside amount on a firm basis. This set-aside would ensure that DEC and PEC would not have access to the set-aside amount of transmission capacity into the PEC East BAA from the Duke BAA on a firm basis, and thereby would fully mitigate the one small screen failure remaining after the transmission projects are completed.

Finally, Mr. Weintraub testified that DEC and PEC proposed that three aspects of the Revised Mitigation Proposal be subject to monitoring by Potomac Economics as an independent monitor. First, Potomac Economics would monitor the PSAs to ensure they remain in effect until the transmission expansion projects are complete. If any of the PSAs terminated prior to completion of the transmission projects, Potomac Economics would monitor whether such PSA is replaced with a new PSA under materially the same terms and conditions. Second, Potomac Economics would monitor the extent to which the Applicants are pursuing the transmission expansion projects within the scope and time frame projected and will report to FERC when the projects have been completed and placed in service. Third, if FERC requires PEC or DEC to set aside portions of the enhanced transmission capability created by these projects, Potomac Economics would monitor the Applicants' compliance with such a transmission use limitation.

As referenced above, by letter filed with the Commission by PEC and DEC on May 16, 2012, PEC and DEC advised the Commission of certain commitments made by PEC and DEC to the ORS with regard to the Revised Mitigation Proposal. The May 16, 2012, letter, along with the clarifying letter of May 21, 2012, are attached as Appendix B to this Order. In this letter, PEC and DEC stated that the costs of the generation capacity used to effectuate the interim mitigation wholesale sales will be allocated to these sales. The capacity costs will be calculated based upon the revenue requirement associated with a utility-specific proxy for the capacity costs of the generating facilities expected to be on the margin during the months and hours the sales will be made, which are assumed to be between July 1, 2012, through May 31, 2015. DEC and PEC will each develop a decrement rider to their respective South Carolina retail rates that reflects these capacity costs. DEC and PEC will file the decrement riders for approval with the Commission and provide a copy to ORS within 30 days after the Merger closes. Upon approval by the Commission, the decrement riders will be fixed and remain in effect and without any future true-ups until the date the interim market power mitigation sales terminate plus the number of days between when such sales began and the time the decrement riders became effective. Provided, however, that if a portion of the interim sales terminate, the riders shall be reduced in proportion to the terminated sales. Appropriate decrement riders will continue in effect until such time as the utilities are relieved of their respective obligations to make the interim mitigation sales. The total system costs of capacity to be allocated away from retail are $43,458,315 for DEC and $21,194,759[5] for PEC.

DEC and PEC further committed not to seek to recover from their South Carolina retail customers any of the non-fuel variable operating and maintenance costs associated with the interim mitigation sales. They further committed not to seek to recover from their South Carolina retail customers any revenue shortfalls resulting from, or any costs associated with, the interim mitigation sales (including but not limited to any negative capacity payments), any revenue deficiency resulting from energy revenues being less than the associated costs and any payment of liquidated damages.

With regard to the permanent transmission mitigation plan, DEC and PEC committed not to seek recovery of any costs associated with the transmission projects in their respective South Carolina retail rates until the expiration of five (5) years following the close of the Merger, and any such request must include a showing that, absent the Merger and the resulting mitigation requirement, the project is needed to provide adequate and reliable retail service and, at the time the request is made, the construction of the project and the incurrence of the associated costs would have been reasonable and prudent. These cost recovery prohibitions do not apply to the Greenville-Kinston-DuPont transmission line project because PEC is simply accelerating the construction of this project.

Finally, DEC and PEC committed not to seek to recover from their South Carolina retail ratepayers any costs associated with running their generating systems on a non-economic basis as a result of their permanent transmission market power mitigation plan to run PEC's Roxboro

[5] The DEC and PEC South Carolina retail allocable portion would be $10,316,657 for DEC and $2,283,121 for PEC.

and Mayo units at full output when necessary to push back against AEP/PJM power flows into PEC in order to achieve improvement in firm import capability from PJM into PEC-East.

The commitments made by DEC and PEC regarding the Revised Mitigation Proposal are the same as those made to the NCUC. The Commission finds that these commitments properly protect and hold harmless DEC's and PEC's South Carolina retail customers and are approved. DEC and PEC shall comply with and implement these commitments as described in Appendices A and B.

As discussed more thoroughly below, the May 16, 2012 letter also re-affirms DEC's and PEC's commitment and guarantee to provide their retail South Carolina customers pro rata benefits equivalent to those approved by the NCUC in its order ruling upon the Merger Application.

B. MOST FAVORED NATIONS STIPULATION AND BENEFITS OF THE MERGER

During the hearing DEC and PEC made the following commitment and stipulation:

> As a condition for Commission approval of the proposed JDA between PEC and DEC, PEC and DEC will provide the Commission a "most favored nations" commitment and will also agree to the ORS proposal for approval of the JDA on a one year trial basis. The "most favored nations" commitment guarantees this Commission and PEC's and DEC's South Carolina retail customers pro rata benefits equivalent to those approved by the North Carolina Utilities Commission ("NCUC") in its order ruling upon Duke Energy Corporation's and Progress Energy, Inc.'s Merger Application.

Tr. pp. 119-120. We also note that, to the extent allowed by South Carolina law, the "most favored nations" commitment extends the protections of the revised Regulatory Conditions and Code of Conduct adopted by the North Carolina Utilities Commission in its June 29, 2012, Order approving the Merger to the South Carolina ratepayers of DEC and PEC. Tr. p. 119.

Although the Commission's focus in this proceeding is on whether the JDA should be approved, the Commission received extensive evidence on the Merger as well. The Applicants' witnesses Rogers, Johnson, and Good testified that the combined company will be the largest regulated utility in the United States, which will possess the size and scale, diversification, and operational excellence to be the foremost utility in the industry. This will translate into continued financial strength and flexibility for dealing with circumstances such as changing regulatory requirements, volatility in the capital markets, economic downturns, as well as other external influences. Tr. pp. 25, 46-47. Witnesses Rogers, Johnson, and Good advocated that the Merger will produce significant benefits for PEC's and DEC's South Carolina customers. Tr. pp. 26-27, 47.

The witnesses further testified that, post-merger, Duke will maintain strong investment-grade credit ratings. Both Moody's and S&P reviewed the proposed transaction and affirmed the credit ratings of the combined company and its subsidiaries on the date of the Merger announcement. Size, scale, and financial strength are important to investors in the utility industry and will support the combined company's ability to attract capital on favorable terms, which is a clear benefit to customers. Investors will also benefit from more stable returns resulting from a higher proportion of the combined company's operations being regulated businesses. For the year ended December 31, 2010, approximately 79% of Duke's business was regulated, while post-merger regulated operations of the combined company will be 88% of its business. Tr. pp. 25, 47.

Witnesses Rogers, Johnson, and Good testified that the combined company will have greater assurance of access to capital, especially in challenging or volatile market conditions.

Upon the close of the Merger, according to testimony, S&P's 'CreditWatch' with positive implications designation is expected to result in an upgrade to the new company's A- corporate credit rating for Progress, PEC, and Progress Energy Florida. Such an upgrade would provide additional benefit to Progress' customers by providing greater access to debt financing as well as a lower cost of debt than would otherwise be possible. Tr. pp. 25, 47.

Witnesses Rogers and Johnson testified that the utility industry faces an extended period of extremely large investments in infrastructure replacement, modernization, and expansion. In order to meet the future demand for electricity, these witnesses testified that both companies will have to invest in new generation that will be more costly than the companies' current average embedded costs. PEC and DEC are well into this intense capital investment program. PEC is investing nearly $2 billion in new natural gas fueled generation. DEC is investing over $3 billion in new clean coal generation and natural gas fueled generation. Much of this generation is simply replacing aging plants that the utilities have concluded are no longer cost effective to operate. The companies also face significant cost increases in order to comply with new proposed Environmental Protection Agency regulations and Nuclear Regulatory Commission regulations. The resulting large infrastructure investment creates two challenges: 1) raising, on reasonable terms, the capital necessary to finance the plant additions; and 2) minimizing the costs to customers from building and operating these new plants. According to witnesses Rogers and Johnson, the Merger will allow them to address both of these challenges and to mitigate potential impacts. Tr. p. 25.

Witnesses Rogers and Johnson emphasized that an important operational benefit of the Merger is centralized management of the two companies' nuclear fleets. Duke operates seven nuclear units, and Progress operates five. Eleven of these 12 nuclear units are in the Carolinas—a geographic proximity that further strengthens the benefits of operating as one large nuclear fleet and particularly supports the combination of these two companies. Additionally, the witnesses stated that the depth and breadth of the combined nuclear management team and workforce is expected to enhance the combined company's ability to operate these plants safely, reliably, and cost effectively. Tr. p. 26.

The Applicants anticipate that, upon the actual integration of Duke's and Progress' service companies, additional cost savings opportunities will be created. This integration transition is expected to be a significant undertaking, and these savings will occur over time as a result of the combination and assimilation of the companies' information technology systems, supply chain functions, generation operations, corporate and administrative programs, and inventories. The Application indicates that there will be up-front costs associated with integrating these functions to yield benefits, but future savings in these areas are expected to be significant. The Applicants testified that customers will receive the benefits of these savings in future rate proceedings. Witnesses Rogers and Johnson emphasized that the synergies and cost savings the Applicants expect to realize over the long term, by merging the two companies' service companies, will help mitigate, to some extent, the cost increases Progress and Duke expect to experience in the future. Tr. p. 26.

The Application explains that the cost savings realized through the integration of the two companies will result in workforce reductions. Over time, Progress, Duke, PEC and DEC expect their combined workforces to be reduced compared to continued operation as unaffiliated companies. To the maximum extent possible, the Applicants commit to manage these reductions through normal retirements, employee attrition, voluntary retirement programs and similar measures, rather than through forced layoffs.

C. THE JOINT DISPATCH AGREEMENT AND OTHER SAVINGS

Regarding the JDA, the Applicants' witness Weintraub testified that, upon the closing of the Merger, PEC and DEC will begin significant coordination of their operations. These coordinated operations will produce significant operational efficiencies that will directly benefit customers. The primary benefit will result from transitioning individual dispatch of PEC's and DEC's generating assets to combined dispatch via the JDA.

Witness Weintraub testified that, consistent with PEC's and DEC's reliability and contractual obligations as well as applicable laws and regulations, the JDA will allow DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest reasonable cost. Under the JDA, DEC will act as the joint dispatcher for DEC's and PEC's power supply resources. The joint dispatch process will allow PEC and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. Witness Weintraub explained that the JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and PEC. Tr. pp. 133-134.

According to witness Weintraub, the JDA expressly provides that it is not intended to act as a system integration agreement and that DEC and PEC will retain their obligations to serve their own native load customers, to fulfill their own contractual obligations, and to operate their own transmission systems and BAAs. DEC's and PEC's contractual obligations will not be changed by the JDA. This includes their contractual obligations under existing wholesale power contracts and their obligations under the Virginia-Carolinas (VACAR) reserve sharing arrangement. Tr. p. 134.

Witness Weintraub explained that the joint dispatcher will direct the dispatch of both DEC's and PEC's power supply resources, which includes the parties' generation as well as their wholesale power purchases. In addition, the joint dispatcher will be responsible for making short-term (less than one year) wholesale power purchases and sales on behalf of DEC and PEC. DEC and PEC will retain individual responsibility for entering into wholesale power transactions of a year or longer. In carrying out its responsibilities under the JDA, the joint dispatcher is charged with achieving the most economic dispatch plan to serve DEC's and PEC's native load customers, consistent with the provision of reliable service, industry standards, and applicable laws and regulations. In effect, the joint dispatcher has the same goals as the individual utilities prior to the advent of the JDA. The difference is that the joint dispatcher will consider the loads and resources of both utilities, which will achieve a more economic result than the utilities could achieve on a stand-alone basis. The joint dispatch function will employ the same methodologies as the security-constrained economic dispatch function each company performs pre-merger. The post-merger process will simply integrate both companies' generation resources into the dispatch process. Tr. pp. 134-135.

According to witness Weintraub, in general, the joint dispatcher will not distinguish between the utilities' resources in determining how best to serve the combined loads of DEC and PEC. The joint dispatcher will have to consider various factors that might constrain the selection of power supply resources, such as contractual "must-run" obligations for certain resources. Within such parameters, however, the joint dispatcher will treat the resources of both utilities as available to serve the load of both DEC and PEC. To the extent that this results in one utility over-generating (i.e., producing more energy than its load) and the other utility under-generating, the imbalance will be handled through a dynamic schedule between the parties' balancing authority areas. Tr. p. 136.

Witness Weintraub testified that each utility will bear the costs associated with its own power supply resources, as defined under the JDA. For example, DEC and PEC will incur the fuel and O&M costs associated with their own generating facilities. Similarly, each utility will be responsible for the costs it incurs under its own power purchase contracts. After the fact, it will be determined which utility (over-generating utility) provided energy to the other, how much it supplied to the other utility (under-generating utility) in a given hour, and the amount of the savings. The under-generating utility will compensate the over-generating utility at cost for all of its expenses for providing the energy. In order to prevent one utility from unfairly shifting costs to the other and to ensure a reasonable sharing of the savings generated by the joint dispatch, an after-the-fact process will be used to allocate costs and benefits between the utilities. Tr. pp. 136-137.

Under the after-the-fact allocation process for each hour, the joint dispatcher allocates energy to three types of transactions that occurred during the hour: 1) New Non-Native Load Sales; 2) Existing Non-Native Load Sales[6]; and 3) Native Load Sales. The energy allocation process is done in descending order of energy cost (other than energy from "must-run" units)

[6] As explained more thoroughly below, the FERC in its June 8, 2012 order approving the JDA required the elimination of the distinction between New and Existing Non-Native Load sales.

and identifies which power supply resources will be deemed to have served each class of transaction. Once the energy allocation process is complete, the joint dispatcher applies cost allocation provisions contained in the JDA to achieve a reasonable allocation of the costs and benefits of the joint dispatch. Tr. pp. 137-138.

The after-the-fact allocation process determines for each hour the costs each utility would have incurred if its resources had been dispatched on a stand-alone basis, without regard to any Non-Native Load sales opportunities. The difference between the joint dispatch costs and the stand-alone costs represents the cost savings achieved by joint dispatch. These savings then are allocated between PEC and DEC based on each company's share of energy generated in each hour. Tr. p. 139.

Under the joint dispatch process, the energy cost attributable to each utility's native load will be the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the joint dispatcher, which will be treated as payments for energy transfers between the utilities. Thus, the energy cost ultimately incurred by each utility to serve its native load will be equal to the stand-alone costs it would have incurred, but for the joint dispatch arrangement, less the utility's share of the joint dispatch savings. That will be the amount that each utility passes through its retail fuel clause and native load wholesale contracts. This process will result in an annual flow through of the joint dispatch savings for both retail and wholesale customers. Tr. p. 140.

The Applicants' witness, Dr. Kalt, explained that the joint dispatch of DEC's and PEC's generation resources under the JDA is expected to reduce the combined company's fuel and related dispatch costs by approximately $364 million in the first five years after the Merger is completed (2012-2016). These savings come from the use of the combined system's lowest-cost available generation to meet total customer demand. Dr. Kalt testified that, in performing the joint dispatch savings study, he relied on a commonly used security-constrained dispatch production cost model to run optimized least-cost production for the utilities' individual BAAs on a stand-alone basis. He then ran the same model assuming a combined "joint dispatch" across the BAAs, holding constant assumptions about load, fuel prices, existing contracts, etc. A net reduction in the total production costs required to serve system loads represents the estimated savings attributable to the joint dispatch. Tr. pp. 172-173.

Dr. Kalt stated that the estimated cost savings of jointly dispatching the DEC and PEC generation fleets are driven largely by optimizing dispatch so as to minimize fuel costs. This optimization results in lower fuel costs because the joint dispatch creates a larger, more flexible pool of operating assets to be drawn upon when making overall generation dispatch decisions. Joint dispatch enhances the ability to commit and substitute available capacity at a less costly generating unit in one BAA for a more costly unit that otherwise would be required to meet load in another BAA absent the joint dispatch. Tr. pp. 172-173.

Dr. Kalt explained that the savings will vary in magnitude from period to period. Using base case assumptions, he estimated the savings per year to be:

Base Case Savings ($mm)

2012	2013	2014	2015	2016	Total
$38	$49	$64	$97	$116	$364

Tr. p. 173.

Dr. Kalt testified that the estimated benefits will vary if the underlying input assumptions used in the dispatch model are changed. To address this issue, he examined the effect on calculated benefits of changing two important modeling assumptions – fuel prices and load growth. By using a low and high range for both variables, he determined that the estimated benefits from joint dispatch range from $249 million with low load growth ($115 million less than the base case) to $629 million with high fuel prices ($265 million more than the base case). He noted that even the relatively smaller estimated potential benefits associated with an extreme low-load growth case still produce positive savings. Further, he considers the estimated joint dispatch cost savings to be a conservative estimate because the dispatch model does not capture additional sources of benefits associated with joint dispatch that offer real cost savings to the merging parties, as well as ancillary benefits such as enhanced economic activity. Specifically, he stated that the model does not (and cannot) capture the ability of joint dispatch to take advantage of daily fuel and electricity price volatility or potential benefits that can arise for capturing savings within a given hour, nor can the model capture the extent to which future joint planning could further reduce the costs of the merged companies. Finally, the ancillary benefits to the local economy resulting from lower electricity prices were not analyzed. Tr. pp. 174-175.

ORS witness, Jonathan Falk, agreed that the JDA should produce significant savings. However, he raised three issues: (1) that hourly joint dispatch ought to be feasible without a merger; (2) savings in the aggregate do not necessarily mean savings to each individual service territory; and (3) the JDA only allocates operating cost savings leaving open the possibility of cross-subsidization of capital costs on a going-forward basis. Witness Falk suggested that DEC and PEC could realize fuel savings through the implementation of some form of joint dispatch without a merger. He indicated that these savings could be realized by PEC and DEC forming a tight power pool which is nothing more than a JDA without any merging of ownership. However, DEC and PEC witness Dr. Kalt explained that DEC and PEC could not achieve the same level of savings as estimated under their JDA if they operated as unaffiliated participants in a tight power pool arrangement. This is because it is not possible for two unaffiliated parties to engage in the complex, day-to-day real time moment-to-moment decisions necessary to implement the operational integration required to realize such savings. Dr. Kalt also observed that tight power pools may result in increased expenses and may impact the jurisdictional authority of the Commission.

Regarding the issues of the allocation of savings and the possibility of cross-subsidization, witness Falk acknowledged that, until the system is up and running, it is virtually impossible to forecast the importance of these issues. In order to allow PEC, DEC, ORS, the Intervenors, and the Commission to evaluate the materiality of these concerns and measure the benefits of the JDA, he recommended the Commission approve the JDA on a one year trial basis. Tr. pp. 238-241. During cross-examination by Mr. Tiencken, witness Falk testified that the Central Electric Power Cooperative and the Electric Cooperatives of South Carolina, Inc., support a one year trial period. Tr. p. 258.

In addition to the savings to be realized from joint dispatch, PEC and DEC witness Weintraub testified that the significant coordination between PEC and DEC will also create savings through the joint purchase of fuel and fuel transportation and the sharing and implementation of best practices for fuel procurement and use. Witness Weintraub sponsored Exhibit No. 5 to the Application, which is a study performed by Booz & Company ("Booz") for the Applicants, that estimates merger savings for the fuel procurement activities of the combined company. Witness Weintraub explained that Booz utilized specific information from DEC and PEC and Booz's own experiences with previous utility mergers to determine the forecasted fuel savings following the Merger. Tr. p. 140.

Witness Weintraub testified that both companies need natural gas, coal, and the transportation services required to deliver these fuels. With regard to coal transportation, witness Weintraub explained that, by aligning various transportation contracts and taking advantage of opportunities to maximize the economies of scale for the transportation of the combined company's coal requirements, the combined company will reduce its coal transportation costs. The transportation savings opportunity for the new company is based on aligning the lowest rates across common transportation contracts and carriers. Tr. p. 141.

Turning to the procurement of coal, witness Weintraub testified that the annual coal burn of the combined company will range from 23 to 28 million tons over the next five years. By optimizing a combined fuel sourcing plan with greater scope across common coal suppliers, the combined company will reduce overall coal procurement costs. The combined company's purchasing requirements will enhance its position as a leading buyer of coal and provide increased purchasing power in the marketplace, which will benefit customers through lower costs. Tr. p. 141.

With regard to the transportation of natural gas, witness Weintraub stated that, with the addition of interstate natural gas pipeline agreements by both DEC and PEC to support new and existing natural gas generation in the Carolinas, the combined company will utilize common natural gas transportation paths and complementary logistics for the combined natural gas generation fleet. By maximizing the utilization of the combined portfolio of interstate natural gas pipeline agreements, cost savings will be achieved through short-term and potential long-term capacity releases into the market. In addition, fuel savings will be achieved by the avoidance of additional fixed pipeline costs by utilizing non-firm interstate pipeline transactions (backhaul and pipeline segmentation) to serve the natural gas requirements of the combined company. Tr. p. 143.

Witness Weintraub explained that the combined company should be able to achieve substantial fuel savings by the sharing of best practices for coal blending at the combined company's coal power plants. Over the past five years, PEC has invested more than $60 million in its scrubbed coal units to improve the fuel flexibility of these units. These investments have included improvements to the coal-fired boilers, as well as the balance-of-plant components that have expanded the types of coal that can be reliably burned at these PEC coal units. The expansion of coal types that can be burned at the PEC scrubbed units has created competition among different coal basins, resulting in overall lower fuel procurement costs. Some of the investments have been for coal blending infrastructure that has increased blending capabilities to achieve optimal quality blends and procurement economics as well as the blending of cheaper fuels during off-peak hours. The integration of these best practices within the combined company will reduce the fuel costs of the combined company. Tr. pp. 141-142.

Turning to other savings opportunities, witness Weintraub testified that both DEC and PEC utilize common suppliers and transportation providers for limestone. By leveraging the increased limestone volume for the combined company, DEC and PEC expect to lower the delivered reagent costs of the combined company by reducing both the commodity costs and the transportation costs for limestone. In addition to limestone costs, the combined company will have reagent costs for the procurement of ammonia. The combined company intends to leverage its increased purchasing power by consolidating its ammonia volume to achieve more competitive commodity pricing and transportation pricing than could be achieved by stand-alone companies. Tr. pp. 142-143.

Another area of savings noted by witness Weintraub involves combining the natural gas trading and scheduling functions for DEC and PEC. The combined company will eliminate the need for DEC to establish a natural gas trading desk and allow it to avoid two related positions that had been anticipated for meeting the needs of DEC's gas-fired generation fleet. Tr. pp. 143-144.

The Application explains that the Booz fuel savings study (Exhibit No. 5) quantifies these various savings opportunities as follows:

- the leveraging of each entity's expertise in coal transportation services and coal procurement is estimated to result in a combined savings of $115 million over the five-year period 2012-2016;
- savings of $183.9 million over this same five-year period are expected to be created through the application of coal blending practices to DEC's coal use, similar to PEC's current practices; and
- coordinating the use of PEC's and DEC's interstate natural gas pipeline capacity to the greatest extent allowed, reagent procurement efficiencies, and elimination of the need for DEC to establish a natural gas trading

desk, are estimated to produce an additional $31.8 million of fuel savings, for a total of $330.7 million over five years.

Combined with the joint dispatch fuel savings results, gross total fuel savings are estimated to be $694.7 million over five years.

Witness Weintraub stated that the joint dispatch and fuel cost savings will automatically flow through to the utilities' retail customers through their respective fuel clause proceedings. He also explained that, upon the closing of the Merger, both PEC and DEC will file rate decrements to pass through the forecasted fuel savings for 2012. Tr. pp. 133, 140. The rider will be designed to provide PEC's and DEC's retail customers the forecasted savings to be realized from the joint dispatch of their systems as well as other fuel cost savings during calendar year 2012. In each of DEC's and PEC's fuel cost proceedings in the five years after Merger close, they will incorporate the forecasted savings from the joint dispatch of their systems as well as other fuel costs savings for each of those years into the calculation of their respective fuel factors. They will also calculate a true-up of the forecasted amounts for the previous year to the actually experienced savings.

At the hearing, PEC and DEC guaranteed that their retail and wholesale customers would receive their allocable shares of $650 million in total system fuel and fuel-related cost savings over five years. At the close of the fifth year, if actually achieved savings passed through to retail customers in DEC's and PEC's South Carolina fuel cases do not total each company's allocable portion of South Carolina's pro rata share of the $650 million in guaranteed savings, then DEC and PEC will flow through their respective fuel riders in their next cases their allocable shares of the remaining obligation. In the event the actual savings exceed the guarantee, those additional savings will also be flowed through to DEC's and PEC's customers.

In the Additional Direct Testimony of witness Weintraub filed on June 4, 2012, pursuant to the Commission's Order No. 2012-473, Mr. Weintraub addressed the salient elements of a Supplemental Agreement and Stipulation of Settlement (Supplemental Agreement) entered into by DEC, PEC, and the NCUC Public Staff on May 8, 2012. This Supplemental Agreement clarifies and modifies an earlier Agreement and Stipulation of Settlement entered into by DEC, PEC and the NCUC Public Staff on September 2, 2011. The Supplemental Agreement clarifies certain portions of the JDA, creates additional savings for DEC's and PEC's customers, and addresses certain aspects of the $650 million fuel savings guarantee during the first five years following the Merger.

The first clarification concerns how off-system purchases and sales are to be treated in determining savings realized by PEC and DEC from the joint dispatch of their generation facilities. The parties agreed that, in order to properly account for the benefits of joint dispatch for purposes of calculating the JDA savings portion of the $650 million fuel savings guarantee, off-system sales and purchases will be excluded from the calculation (in both the joint dispatch generation stack and the stand-alone generation stacks). Actual savings that result from purchases and the displacement of higher cost generation that results from such purchases will flow through DEC's and PEC's annual fuel charge adjustment proceedings in the same manner such lower costs/savings have been treated pre-merger.

The second clarification concerns the increased consumption of reagents by DEC resulting from its burning of non-traditional coals due to greater use of coal blending. Fuel blending generally refers to the exercise of fuel flexibility in electricity generation and involves the burning of coals with higher sulfur and ash contents. Such blending will result in the consumption of greater amounts of reagents than would be the case if the higher sulfur and ash content coals were not burned. The Supplemental Agreement clarifies that the calculation of the $650 million fuel savings guarantee will not be reduced by the increased reagent costs resulting from the increased consumption of reagents associated with fuel blending. The recovery of these increased reagent costs, if otherwise reasonable and prudently incurred, will be allowed in DEC's annual fuel charge proceedings.

The final clarification relates to how savings realized by DEC from greater use of coal blending following the Merger are to be calculated for purposes of the $650 million fuel savings guarantee.

Mr. Weintraub further explained that the Supplemental Agreement modifies DEC's and PEC's earlier agreement with the NCUC Public Staff that DEC's and PEC's North Carolina retail customers would receive their allocable share of $650 million of total system fuel and fuel-related cost savings over the first five years following the close of the Merger. He stated that the reduction in natural gas prices since the beginning of 2012 has significantly impacted PEC's and DEC's opportunity to achieve fuel savings from coal blending. Exhibit No. 5 to the Applicants' Merger Application indicates that savings of $183.9 million during the first five years following the close of the Merger are expected to be achieved through coal blending. Mr. Weintraub testified that the dramatic reduction in natural gas prices since the beginning of 2012 has materially reduced the amount of coal being consumed by PEC and DEC. Current forecasts of natural gas prices do not indicate any material change in the relative prices of coal and natural gas in the near term. Therefore, over the next several years, PEC's and DEC's coal consumption is expected to remain at the current relatively low levels. This reduced use of coal materially impacts DEC's forecasted ability to achieve the $183.9 million in coal blending savings during the first five years after the Merger. As a result, the NCUC Public Staff and the Applicants agreed that, if at the end of the five-year period, (1) DEC and PEC have not achieved all of the $650 million in guaranteed savings in spite of their best efforts; and (2) the decline in natural gas prices has resulted in fewer tons of coal having been delivered to the three DEC generating plants designated for coal blending in Exhibit 5 and therefore impaired DEC's ability to achieve the forecasted coal blending savings, then the five-year period will be extended by 18 months.

Mr. Weintraub emphasized in his testimony that PEC and DEC are still committed to providing both their South Carolina and North Carolina retail customers their allocable shares of the guaranteed $650 million in fuel savings during the first five years following the closing of the Merger. However, he explained that, at the time of the hearing before this Commission in December of 2011, no one foresaw the dramatic decrease in natural gas prices that has occurred in 2012 or that natural gas prices would be forecasted to remain at very low levels for the next several years. This reduction in natural gas prices has resulted in natural gas fired generation being less expensive than coal fired generation. If this situation persists, then following the Merger DEC will not be burning enough coal at its Marshall, Belews Creek, and Allen plants to achieve the forecasted savings of approximately $184 million. Thus, Mr. Weintraub testified that DEC and PEC need an additional 18 months to achieve the $650 million in fuel savings if DEC is unable to burn as much coal as was originally forecasted. He emphasized that DEC's and PEC's South Carolina customers are realizing and will realize fuel savings, the savings will just be created by the changes in the fuel markets rather than from coal blending. Either way DEC's and PEC's customers enjoy significant savings, they will just be achieved in a manner not originally contemplated. Of course, such natural gas fired generation savings will not be counted toward the achievement of the $650 million guarantee in fuel savings.

Another modification addressed by Mr. Weintraub in his Additional Direct Testimony relates to the recovery of capital costs associated with achieving merger savings. In recognition of the delay in the expected closing of the Merger from January 1, 2012, to the June-July 2012 time frame, the Applicants and the NCUC Public Staff agreed that their September 2, 2011, Agreement and Stipulation of Settlement should be revised to allow PEC and DEC to seek recovery of any and all capital costs incurred to generate merger savings provided such costs are incurred within three years of the closing of the Merger, except for capital costs to achieve fuel blending savings incurred by DEC. The Supplemental Agreement provides that there should not be any time limitation regarding DEC seeking recovery of costs to achieve coal blending savings. Additionally, the standard for recovery was changed to allow PEC and DEC to recover all capital costs incurred to generate merger savings (including fuel blending savings) in accordance with normal ratemaking practices.

Mr. Weintraub explained that, in consideration for the NCUC Public Staff agreeing to these clarifications and modifications in the Supplemental Agreement and Stipulation of Settlement, PEC and DEC agreed to waive their right to seek recovery of employee severance costs. These costs are forecasted to be $226,000,000 on a system basis. Mr. Weintraub stated that the ORS, which is a party to the North Carolina proceeding, has filed a letter with the

NCUC generally supporting the Supplemental Agreement and Stipulation of Settlement, including the 18-month extension.

Mr. Weintraub also addressed certain commitments DEC and PEC made to the ORS in settlement of the ORS' issues in the North Carolina Merger proceeding. Mr. Weintraub states that these commitments create additional value for DEC's and PEC's South Carolina customers that more than offset the 18-month extension to achieve the guaranteed $650 million in fuel savings. He noted that DEC and PEC have agreed to make annual community support and charitable contributions in South Carolina for four years following the close of the Merger. The annual contributions will be based on DEC's and PEC's average contributions over the time period 2006-2010. The annual amount for DEC is $1,866,862, and for PEC the annual amount is $788,000 for an annual total of $2,654,862. In addition, DEC and PEC have committed to make a contribution in the amount of $3.75 million in the first year following the close of the Merger to support workforce development and low income energy assistance in DEC's and PEC's South Carolina service territories. The contribution will be allocated in proportion to the number of South Carolina customers served by each utility. Finally, Mr. Weintraub stated that DEC and PEC have committed not to seek recovery of the employee severance costs they will incur in reducing their workforces to achieve merger savings from their South Carolina retail customers. These costs are forecasted to be $44,000,000 on a South Carolina retail basis.

The Commission finds that the changed circumstances described by Mr. Weintraub, along with the additional value resulting from the commitments made by DEC and PEC to the ORS, justify the Commission allowing DEC and PEC an additional 18 months beyond the first five years following the close of the Merger to provide their South Carolina retail customers their allocable share of the guaranteed $650 million in fuel savings.

As noted earlier, on June 8, 2012, FERC approved the JDA, provided that DEC and PEC agreed to two revisions. The required revisions were the deletion of Sections 3.2(c)(ii)-(iv) and the elimination of the distinction between existing non-native load customers and new non-native load customers. On June 12, 2012, DEC and PEC notified the Commission that they would agree to these revisions and submitted a revised conforming JDA. DEC and PEC also indicated that they intended to submit the revised JDA to FERC no later than 10 days after the close of the Merger. On June 13, 2012, DEC and PEC filed the Further Supplemental Testimony of Sasha Weintraub explaining the JDA revisions.

In that testimony, Mr. Weintraub explained that none of the revisions alter DEC's and PEC's ability to achieve the forecasted fuel savings or otherwise impair any of the benefits of the JDA to South Carolina customers. He stated that Sections 3.2(c)(ii)-(iv) of the JDA contain language that DEC and PEC were required to insert into affiliate agreements pursuant to their North Carolina regulatory conditions. The language of Sections 3.2(c)(ii)-(iv) is substantially similar to language in those regulatory conditions. Therefore, the deletion of this language from the JDA does not relieve DEC and PEC from these obligations. In fact, Mr. Weintraub noted that FERC stated in the paragraph discussing the deletion of Sections 3.2(c)(ii)-(iv) that "we offer no view on the North Carolina Commission's authority to impose or apply such requirements in its proceedings." (FERC JDA Order page 13, paragraph 37). In addition, Mr. Weintraub testified that on June 13, 2012, the NCUC Public Staff filed proposed additional regulatory conditions in the NCUC merger docket to address the deletion of this language from the JDA. DEC and PEC do not oppose these revisions.

Turning to FERC's second revision, Mr. Weintraub explained that FERC required DEC and PEC to eliminate the distinction in the JDA between sales to existing non-native load customers and sales to new non-native load customers. He further explained that merging existing non-native load sales and new non-native load sales into one class for purposes of the JDA has no impact on the $650 million savings guarantee, because this revision only deals with non-native load transactions and does not impact native load. Furthermore, he stated that the class of existing non-native load sales is small, only two contracts, and that, when those two contracts expire, the class of "existing non-native load sales" will disappear.

Finally, Mr. Weintraub testified that merging these two types of sales does not change the total costs allocated to non-native load sales for purposes of the JDA. The resources allocated to native load will only be those that remain after the highest cost resources have been allocated to non-native load sales. The only difference will be that, instead of first allocating the least expensive of these higher cost resources to "existing" non-native load sales and the remainder to "new" non-native load sales, the most expensive resources will be allocated to non-native load sales as a whole. Therefore, this change will not affect the allocation of costs to native load.

D. OTHER ISSUES

The City of Orangeburg opposed approval of the JDA, not on the grounds that it will not provide substantial savings to PEC's and DEC's South Carolina customers, but rather because, Orangeburg argues, the Commission does not have jurisdiction to approve the JDA.

As explained earlier in this order, the JDA involves the transfer of operational control of PEC's generating assets to DEC. These PEC generating assets are used and useful and are included in PEC's rate base. Thus, pursuant to S.C. Code Ann. § 58-27-1300, which is set forth in its entirety below, Commission approval is clearly required prior to their transfer to DEC.

S.C. Code Ann. § 58-27-1300 (Supp. 2011) states:

> No electrical utility, without the approval of the commission and compliance with all other existing requirements of the laws of the State in relation thereto, may sell, assign, transfer, lease, consolidate, or merge its utility property, powers, franchises, or privileges, or any of them, ...without prior approval of the commission..... For purposes of this section, "utility property" shall include property used and useful to provide customers with electric service and which has been properly included in the electric utility's rate base, including construction work in progress or property held to serve future customers.

Furthermore, elimination of certain language in the JDA that the City finds offensive will not provide Orangeburg the relief it seeks. The Applicants' witnesses Rogers and Johnson explained in their rebuttal testimony that Orangeburg's basic concern with the JDA relates to a decision by the NCUC regarding the allocation of electric utility costs between retail and wholesale customers for the purposes of establishing North Carolina retail electric rates. Orangeburg believes the North Carolina cost allocation methodology harms Orangeburg's opportunities to purchase electricity in the wholesale market at favorable rates, thus it opposes this cost allocation methodology. The proposed JDA is consistent with the existing North Carolina retail/wholesale cost allocation methodology. Orangeburg has challenged this cost allocation process before the NCUC and the North Carolina courts and was unsuccessful in both forums. A rejection of the JDA by this Commission will not alter these decisions or the NCUC's use of this cost allocation methodology. Tr. p. 35.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

After thorough consideration of the entire record, including the testimony and all exhibits, and the applicable law, the Commission makes the following findings of fact and conclusions of law:

1. DEC is an electrical utility as defined by S.C. Code Ann. § 58-27-10(7) authorized to generate, transmit and distribute electric power in its service territory in South Carolina.

2. PEC is an electrical utility as defined by S.C. Code Ann. § 58-27-10(7) authorized to generate, transmit and distribute electric power in its service territory in South Carolina.

3. Pursuant to S.C. Code Ann. § 58-27-140 (Supp. 2011), the Commission is vested with general powers to supervise and regulate the service of electrical utilities and pursuant to S.C. Code Ann. § 58-27-1300, the Commission must approve the transfer of any utility property, including the transfer of operational control of PEC's generating assets as contemplated by the JDA.

4. We find that the JDA is an interchange or interconnection agreement as contemplated by S.C. Code Ann. § 58-27-865(E) and is not intended to act as a system integration agreement and that DEC and PEC will retain their obligations to serve their own native load customers, to fulfill their own contractual obligations, and to operate their own transmission systems and balancing authority areas. Further, all rates and services of PEC and DEC continue to be subject to the same oversight of this Commission as was the case before the merger of Duke and Progress.

5. We find that the joint dispatch process will allow PEC and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis.

6. We conclude that the savings to be realized by PEC and DEC from the JDA are real and substantial. No party to this proceeding presented any evidence that the JDA will not produce substantial savings for PEC's and DEC's South Carolina customers. The Commission finds that the revisions required by FERC do not diminish the benefits of the JDA to DEC's and PEC's South Carolina retail customers.

7. This Commission is mindful of the evolving nature of DEC's and PEC's planning for use of existing and future generation resources. Until the two companies are able to construct IRPs that benefit from full knowledge of the other company's needs and resources, it is uncertain how their combined future decision-making will impact their ratepayers. In addition, because of the sheer size of their operations, it is also uncertain how ripple effects might impact other utilities, other South Carolina ratepayers, and our state's economy.

8. To address any issues or risks associated with the JDA and the evolving nature of the Applicants' planning, we find that the JDA should be approved on a one (1) year trial basis effective with the closing of the Merger. The one (1) year trial basis has been recommended by ORS, supported by the Electric Cooperatives and Nucor, and agreed to by the Applicants.

9. We find that the Commission does have jurisdiction to approve the JDA pursuant to S.C. Code Ann. § 58-27-1300 (Supp. 2011).

10. During the hearing the Applicants committed to a "most favored nations" treatment for South Carolina. This commitment ensures that PEC's and DEC's South Carolina

customers receive the same benefits, on a pro rata basis, as those provided to PEC's and DEC's North Carolina retail customers as a result of the NCUC's Order ruling upon Duke's and Progress' Merger Application, including the adoption of the revised Regulatory Conditions and Code of Conduct to the extent allowable by South Carolina law.

11. DEC and PEC have guaranteed that DEC's and PEC's South Carolina retail customers will receive their allocable share of $650 million of total system fuel and fuel-related cost savings over five years upon close of the Merger. DEC and PEC shall have 18 additional months to achieve the $650 million in system fuel and fuel-related cost savings if, at the end of the five-year period, (1) DEC and PEC have not achieved all of the $650 million in guaranteed savings in spite of their best efforts; and (2) the decline in natural gas prices has resulted in fewer tons of coal having been delivered to the three DEC generating plants designated for coal blending in Exhibit 5. At the end of that period, if the savings passed through to retail customers in DEC's and PEC's South Carolina fuel cases do not total each company's allocable portion of South Carolina's pro rata share of the $650 million in guaranteed savings, then in DEC's and PEC's subsequent fuel cases each will flow through their respective fuel riders their allocable share of the remaining obligation. In the event the actual savings exceed the guarantee, those additional savings will also be flowed through to DEC's and PEC's customers.

12. DEC and PEC have also made the following commitments to the ORS as a condition of approval of the JDA: DEC and PEC shall make annual community support and charitable contributions in South Carolina for four years following the close of the Merger. The annual contributions will be based on the DEC's and PEC's average contributions over the time period 2006-2010. The annual amount for DEC is $1,866,862, and for PEC the annual amount

is $788,000 for an annual total of $2,654,862. DEC and PEC shall make a contribution in the amount of $3.75 million in the first year following the close of the Merger to support workforce development and low income energy assistance in DEC's and PEC's South Carolina service territories. The contribution will be allocated in proportion to the number of South Carolina customers served by each utility. DEC and PEC shall not seek recovery of the employee severance costs they will incur in reducing their workforces to achieve merger savings. These costs are forecasted to be $226,000,000 on a system basis and $44,000,000 on a South Carolina retail basis.

IT IS THEREFORE ORDERED THAT:

1. The Joint Dispatch Agreement, as approved by FERC, is approved by this Commission on a one year trial basis effective with the closing of the Merger, and all commitments made by the Applicants as referenced herein are accepted as a condition of such approval;

2. As a condition of this Commission's approval of the Joint Dispatch Agreement, PEC and DEC guarantee this Commission and PEC's and DEC's retail customers pro rata benefits equivalent to those approved by the NCUC in its Order ruling upon Duke Energy Corporation's and Progress Energy, Inc.'s Merger Application, including, but not limited to the protections of the revised Regulatory Conditions and Code of Conduct, to the extent allowable by South Carolina law;

3. As a condition of this Commission's approval of the Joint Dispatch Agreement, PEC and DEC guarantee this Commission and their retail and wholesale customers that customers will receive their allocable share of $650 million in total system fuel and fuel-related

cost savings over the first five years after close of the Merger. DEC and PEC, however, shall have 18 additional months to achieve and pass through South Carolina customers' allocable share of the $650 million in system fuel and fuel-related cost savings if, at the end of the five-year period, (1) DEC and PEC have not achieved all of the $650 million in guaranteed savings in spite of their best efforts; and (2) the decline in natural gas prices has resulted in fewer tons of coal having been delivered to the three DEC generating plants designated for coal blending in Exhibit 5. At the end of that period, if the savings passed through to retail customers in DEC's and PEC's South Carolina fuel cases do not total each company's allocable portion of South Carolina's pro rata share of the $650 million in guaranteed savings, then in DEC's and PEC's subsequent fuel cases each will flow through their respective fuel riders their allocated share of the remaining obligation. In the event the actual savings exceed the guarantee, those additional savings will also be flowed through to DEC's and PEC's customers.

4. As a condition of our approval of the Joint Dispatch Agreement DEC and PEC shall: a) make annual community support and charitable contributions in South Carolina for four years following the close of the Merger. The annual contributions will be based on the DEC's and PEC's average contributions over the time period 2006-2010. The annual amount for DEC is $1,866,862, and for PEC the annual amount is $788,000 for an annual total of $2,654,862; b) make a contribution in the amount of $3.75 million in the first year following the close of the Merger to support workforce development and low income energy assistance in DEC's and PEC's South Carolina service territories. The contribution will be allocated in proportion to the number of South Carolina customers served by each utility; and c) DEC and PEC shall not seek recovery of the employee severance costs they will incur in reducing their

workforces to achieve merger savings. These costs are forecasted to be $226,000,000 on a system basis and $44,000,000 on a South Carolina retail basis.

5. DEC and PEC shall file electronically with the Commission decrement riders to their South Carolina retail rates within 30 days of the close of the Merger to pass through to their respective customers: a) their allocable shares of the $650 million in system fuel and fuel-related cost savings; and b) the capacity cost allocated to the interim wholesale sales consistent with Appendices A and B to this Order.

6. In addition to the reports currently received by this Commission, DEC and PEC shall file with this Commission all reports required by the NCUC's Order on the Merger issued on June 29, 2012 (or which may be required by the NCUC in the future) as are relevant and appropriate under South Carolina law, *e.g.*, the reports listed in Appendix C to this Order. Further, copies of such reports should be provided to the ORS, as well as any other reports which may be requested by the ORS. This Commission retains jurisdiction to determine the appropriateness of the list of reports to be submitted to the Commission.

7. DEC and PEC shall provide within 30 days of receipt of this Order the final versions of the Revised Code of Conduct, Regulatory Conditions, and the final version of the Joint Dispatch Agreement and final version of the Mitigation Plan filed with FERC.

8. The Settlement Agreement between DEC and PEC and the Environmental Intervenors is approved.

9. By May 2, 2013, interested Parties in the present docket shall submit proposed procedures, including due dates for filings, for the one year review of the JDA, to be opened

under a new docket. Those Parties shall include procedures for reporting on the promised fuel and fuel-related cost savings.

10. By July 2, 2013, DEC and PEC shall certify compliance with the commitments regarding workforce development, low income energy assistance, annual community support and charitable contributions.

11. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

John E. Howard, Chairman

ATTEST:

David A. Wright, Vice Chairman
(SEAL)

Appendix A
Docket No. 2011-158-E
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Progress Energy

December 13, 2011

The Honorable Jocelyn G. Boyd
Chief Clerk / Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, SC 29210

RE: SCPSC Docket No. 2011-158-E

Dear Mrs. Boyd:

The purpose of this letter is to memorialize the stipulation and commitment made by Progress Energy Carolinas, Inc. ("PEC") and Duke Energy Carolinas, LLC ("DEC") during the hearing in this docket held December 12, 2011.

As a condition for Commission approval of the proposed Joint Dispatch Agreement ("JDA") between PEC and DEC, PEC and DEC will provide the Commission a "most favored nations" commitment and will also agree to the ORS proposal for approval of the Joint Dispatch Agreement on a one year trial basis. The "most favored nations" commitment guarantees this Commission and PEC's and DEC's retail customers pro rata benefits equivalent to those approved by the North Carolina Utilities Commission in its order ruling upon Duke Energy Corporation's and Progress Energy Carolinas, Inc.'s merger application.

Very truly yours,

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

STAREG2070

Progress Energy Service Company, LLC
PO Box 1551
Raleigh NC 27602

Appendix B
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Progress Energy

May 16, 2012

VIA ELECTRONIC FILING

Jocelyn G. Boyd, Esquire
Chief Clerk & Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

RE: Application Regarding the Acquisition of Progress Energy Incorporated by Duke Energy Corporation and Merger of Progress Energy Carolinas, Incorporated and Duke Energy Carolinas, LLC - **Docket No. 2011-158-E** (See also Docket No. 2011-68-E)

Dear Mrs. Boyd:

The purpose of this letter is to advise the Public Service Commission of South Carolina (the "Commission") of certain commitments Duke Energy Carolinas, LLC ("DEC") and Progress Energy Carolinas, Inc. ("PEC"), (collectively referred to in this letter as "the Utilities"), have made to the South Carolina Office of Regulatory Staff ("ORS") with regard to the Revised Market Power Mitigation Proposal ("Revised Mitigation Proposal") filed with the Federal Energy Regulatory Commission ("FERC") by Progress Energy, Inc. ("Progress") and Duke Energy Corporation ("Duke") on March 26, 2012. The Revised Market Power Mitigation Proposal was filed by Duke and Progress pursuant to an order issued by the FERC on December 14, 2011, which rejected a previous mitigation proposal filed by Duke and Progress.

The Revised Mitigation Proposal has two elements: 1) an interim mitigation mechanism that involves the sale of capacity ("Mitigation Capacity") and energy to new third-party wholesale market participants ("Interim Mitigation Sales"); and 2) a permanent mitigation proposal that involves the construction of new transmission facilities and a commitment to run certain generating units in a specified manner ("Permanent Transmission Mitigation"). As proposed, the Interim Mitigation Sales will terminate once all of the new proposed transmission facilities have been constructed and placed into service. These two (2) market power mitigation mechanisms create state retail cost recovery issues. To address these issues the Utilities have made the following commitments to the ORS to hold their South Carolina retail ratepayers harmless:

Progress Energy Service Company, LLC
PO Box 1551
Raleigh NC 27602

A. Interim Mitigation Sales

1. The costs of the Mitigation Capacity will be allocated to the Utilities' wholesale jurisdiction. These costs shall be calculated based upon the revenue requirement associated with a utility-specific proxy for the capacity costs of the generating facilities expected to be on the margin during the months and hours the Interim Mitigation Sales will be made, which are assumed to be between July 1, 2012 through May 31, 2015.

2. DEC and PEC will each develop a decrement rider to their respective South Carolina retail rates that reflects the Mitigation Capacity costs described in subsection (1) above, calculated as follows:

   a) The Mitigation Capacity MWs under contract for each period shall be increased to reflect reserve margins contained in the Utilities' 2011 filed Integrated Resource Plans.

   b) The Mitigation Capacity MWs, including the associated reserve margins, shall be multiplied by the number of hours that the capacity is contracted for and the hourly capacity cost per MW based upon the agreed upon utility-specific proxy.

   c) These capacity costs shall include a rate of return on production plant, step-up transformer facilities, general plant, and associated rate base items. Additional costs to be included are fixed O&M (which include an appropriate allocation of Administrative and General ("A&G") costs, depreciation expense, and general taxes. The total system costs of Mitigation Capacity to be allocated away from retail are $43,458,315 for DEC and $21,194,759[1] for PEC.

   d) Such capacity costs shall be allocated between and among jurisdictions using the production plant allocation methodology approved in DEC's and PEC's most recent general rate cases. For DEC and PEC, the current Commission-approved methodology is Summer CP. Use of these particular allocation methodologies shall not be considered as precedent in any future cases, including general rate cases.

   e) The decrement shall be determined by dividing each utility's Mitigation Capacity total projected South Carolina retail capacity costs for July 1, 2012, through May 31, 2015, by each utility's projected South Carolina retail kilowatt-hour sales for the same period in accordance with Appendix A.

[1] The DEC and PEC South Carolina retail allocable portion would be $10,316,657 for DEC and $2,283,121 for PEC.

3. The Utilities shall file such decrement riders for approval with the Commission and provide a copy to ORS within 30 days after the Merger closes. Upon approval by the Commission, the decrement riders shall be fixed and remain in effect and without any future true-ups until the date the Interim Mitigation Sales are terminated plus the number of days between when such sales began and the time the decrement riders became effective. Provided, however, that if a portion of the interim sales terminate, the riders shall be reduced in proportion to the terminated sales. Appropriate decrement riders will continue in effect until such time as the Utilities are relieved of their respective obligations to make the Interim Mitigation Sales.

4. Interim Mitigation Sales shall be treated as a separate category of New Non-Native Load Sales and shall be deemed to have been satisfied by the highest energy costs assigned to New Non-Native Load Sales.

5. The Utilities shall not seek to recover from their South Carolina retail customers any of the non-fuel variable operating and maintenance costs associated with the Interim Mitigation Sales.

6. The Utilities shall not seek to recover from their South Carolina retail customers any revenue shortfalls resulting from, or any costs associated with, the Interim Mitigation Sales, including but not limited to any negative capacity payments, any revenue deficiency resulting from energy revenues being less than the associated costs and any payment of liquidated damages.

B. Permanent Transmission Mitigation

DEC and PEC will not assign costs associated with Permanent Transmission Mitigation projects into their wholesale transmission rates until the later of the expiration of the five-year FERC hold harmless period or such time as the Utilities have received regulatory approval to assign those costs to their retail native loads, effective on the date they are first permitted to begin recovering those costs.

1. The Utilities shall not seek recovery in their respective South Carolina retail rates of any of the costs associated with the Permanent Transmission Mitigation projects except as follows:

   a) The Utilities may request recovery of costs associated with a Permanent Transmission Mitigation project in their respective South Carolina retail rates upon the expiration of five (5) years following the close of the merger, and any such request shall include a showing that the requesting utility also intends to pursue recovery from its wholesale customers effective on the date it is permitted to begin recovery of such costs in its South Carolina retail rates.

b) Any request by DEC or PEC to recover the costs associated with a Permanent Transmission Mitigation project in its South Carolina retail rates must be supported by evidence sufficient to show that, absent the merger and the resulting mitigation requirement, (i) the project is needed to provide adequate and reliable retail service, and (ii) at the time the request is made, the construction of the project and the incurrence of the associated costs would have been reasonable and prudent.

c) If the requisite showing has been made pursuant to (a) and (b) above, the Utilities may seek inclusion of only the net depreciated cost of the Permanent Transmission Mitigation projects at the time of the request, and shall not request any deferral of any costs associated with the projects for ratemaking purposes.

d) If subsequent to the inclusion of the costs associated with a Permanent Transmission Mitigation project in South Carolina retail rates, DEC or PEC is not successful in incorporating the correct jurisdictional share of those costs into the cost-based formula rate prescribed by its FERC approved Open Access Transmission Tariffs and, therefore, does not recover all of such costs from its wholesale or firm transmission-only customers, then the corresponding proportionate share of such costs that have been approved for inclusion in retail rates shall be removed and refunds made accordingly (e.g., if 20% of the costs allocated to wholesale are not recovered, then 20% of the portion allocated to retail shall be excluded and refunded).

2. Paragraph B.1 above does not apply to the Greenville-Kinston-DuPont transmission line project. PEC may seek to include the costs associated with this line in its South Carolina retail rates any time after the line is placed in service, in accordance with normal ratemaking practice requirements.

3. The Utilities shall not recover from their South Carolina retail ratepayers any costs associated with running their generating systems on a non-economic basis as a result of the FERC Permanent Transmission Mitigation commitment to run the Roxboro and Mayo units at full output when necessary to push back against AEP/PJM power flows into PEC in order to achieve improvement in firm import capability from PJM into PEC-East. PEC, through special operating procedures[2] maintained at its Energy Control Center ("ECC"), shall (a) document each instance in which any of the Roxboro and Mayo units operate out of merit dispatch order and (b) specify each instance during which the approved procedure for implementing the Permanent Transmission

[2] The ECC will monitor the AEP Danville/East Danville transmission line that interconnects with PEC's system north of the Roxboro and Mayo plants, and, if line-overloading issues associated with power flows from PJM into PEC are found at a time that the Roxboro and Mayo units are not operating at full power output, the ECC will direct both the Roxboro and Mayo plants to increase their output to full power, per the special operating procedures for this type of situation.

Mitigation commitment was used. For each use of the procedure, the following information shall be included by PEC in its monthly fuel report:

- the date, exact times, and duration;
- a detailed description of the order of dispatch under the joint dispatch agreement that would have occurred if the procedure had not been used;
- the incremental difference in fuel, fuel-related, and variable O&M costs, on a joint dispatch basis; and
- the effect on joint dispatch savings to be split between DEC and PEC.

C. DEC and PEC re-affirm their commitment and guarantee contained in the Utilities' December 13, 2011 letter filed with the Commission in this same docket to provide their retail South Carolina customers pro rata benefits equivalent to those approved by the North Carolina Utilities Commission in its order ruling upon Duke's and Progress' merger application.

D. The commitments described in this letter are contingent upon the FERC approving the Revised Mitigation Proposal in Docket No. EC11-60-004; the Joint Dispatch Agreement between DEC and PEC, re-filed with the FERC on March 26, 2012, in Docket Nos. ER12-1338-000, ER12-1347-000, and ER11-3306-000; and the Joint Open Access Transmission Tariff, as re-filed in Docket Nos. ER12-1343-000, ER12-1345-000, ER12-1346-000, and ER11-3307-000, all without material condition or change.

By copy of this letter we are serving the same on all parties of record. Should you have any questions, please do not hesitate to contact me.

Respectfully yours,

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

cc: Parties of Record

STAREG2536

DUKE ENERGY CAROLINAS AND PROGRESS ENERGY CAROLINAS

Revenue Requirement of FERC Mitigation Capacity
Summary of 35-Month SC Retail Decrement Rider

Effective for Service Rendered July 1, 2012 through May 31, 2015

		Duke Energy Carolinas	Progress Energy Carolinas
SC Retail Mitigation Capacity Allocation	1/	($10,316,656)	($2,283,121)
Forecast SC Retail kWh Sales	2/	63,634,708,399	19,100,771,698
Decrement $/kWh Sales		($0.000162)	($0.000120)
Billing Adj. - SC GRT and SCPSC Utility Assessment Fee		1.004536	1.003010
Proposed SC Retail Rider $/kWh		($0.000163)	($0.00012)

Footnotes:
1/ Based on Stipulated Methodology and 2010 Cost of Service Study for DEC, 2011 Cost of Service Study for PEC
2/ Based on September 2011 IRP Filing

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Progress Energy

May 21, 2012

Mrs. Jocelyn G. Boyd
Chief Clerk / Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, SC 29210

Dear Mrs. Boyd:

The purpose of this letter is twofold. First, Progress Energy Carolinas, Inc. ("PEC") and Duke Energy Carolinas, LLC ("DEC") wish to affirm to the Commission that neither the Supplemental Agreement and Stipulation of Settlement entered into by Progress Energy, Inc., Duke Energy Corporation and the North Carolina Public Staff, filed with the North Carolina Utilities Commission on May 8, 2012, nor the commitments made by DEC and PEC to the Office of Regulatory Staff described in my letter of May 16, 2012, alter or affect the Joint Dispatch Agreement ("JDA"). The forecasted savings to be produced by joint dispatch have not decreased and the terms and conditions have not changed. The only relationship between the JDA and the Supplemental Agreement is the forecasted savings from joint dispatch are included in the projected $650 million of total system savings. The provision of the Supplemental Agreement that allows DEC and PEC an additional 18 months to achieve the $650 million in fuel savings is associated with the possibility that the utilities will not burn as much coal as was assumed in estimating the coal blending savings, not joint dispatch.

Secondly, PEC and DEC wish to clarify a statement contained in the commitment letter filed with the Public Service Commission on May 16, 2012 in Docket No. 2011-158-E. In Section A.1 of the letter, under the heading Interim Mitigation Sales, it states that "The costs of the Mitigation Capacity will be allocated to the Utilities' wholesale jurisdiction." This statement was deficient, standing alone, to accurately describe the wholesale allocation. The capacity costs in question will be allocated to the actual mitigation wholesale sales, not PEC's and DEC's wholesale jurisdiction in the aggregate. To the extent the revenues received by PEC and DEC from these sales are less than the allocated costs, PEC's and DEC's shareholders will absorb that loss.

Yours very truly,

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

STAREG2545

Progress Energy Service Company, LLC
PO Box 1551
Raleigh NC 27602

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Selected Reports Required by the North Carolina Utilities Commission's Order Issued on June 29, 2012 on the Merger of Duke Energy Corporation and Progress Energy, Inc.

1. Monthly reports of tracked fuel savings with monthly fuel reports.
2. FERC Form 1.
3. Integrated Resource Plans.
4. Notice of Filing or Contract for RTO Membership or Withdrawal.
5. Cost Allocation Manuals with respect to goods or services provided by DEC or PEC, etc.
6. Report of any business combination transaction savings.
7. Changes to Electric Cost of Service Manuals.
8. Reports of Duke Energy capital contributions to DEC and PEC.
9. Notice of affiliate bankruptcy.
10. Notice of merger, acquisition or other business combination of DEC or PEC impacting rates or services or those that are not expected to impact rates or services but are $\geq$ \$1.5 billion.
11. Report of violations of Regulatory Conditions and Code of Conduct or Code of Conduct.
12. Request for waiver of aspects of Code of Conduct.

Fitch Affirms Progress Energy's Ratings on Duke Merger Announcement; Outlook Stable

January 10 2011 11:43 AM Eastern Standard Time

NEW YORK--(BUSINESS WIRE)--Fitch Ratings has affirmed the ratings for Progress Energy, Inc. (Progress) and its subsidiaries following the announcement of an agreement to merge with Duke Energy, Inc. (Duke, not rated by Fitch) in a stock for stock transaction. Today's rating actions include the affirmation of Progress' Issuer Default Rating (IDR) at 'BBB' and affect approximately $12 billion of debt. The Rating Outlook is Stable. A detailed list of rating actions follows at the end of this release.

Key rating drivers include similarities between the two companies' business risk and credit profiles as well as standalone credit metrics at Progress that are consistent with Fitch's 'BBB' IDR guidelines. Also, the merger is expected to produce business advantages, including opportunities for future efficiencies, economies of scale, and greater diversity and there would be no incremental debt associated with the merger.

Duke's consolidated credit ratios post merger are anticipated to be consistent with Fitch's benchmarks and comparable ratios for highly-regulated utility peers with a 'BBB' IDR. The combined entity is expected to have funds from operations (FFO) interest coverage in excess of 4 times (x). Approximately 85% of consolidated pro forma operating income is from regulated utilities. Pro forma combined liquidity is considered strong, with approximately $1.5 billion of cash on hand and available credit facilities of $5.3 billion as of Sept. 30, 2010. At closing of the merger, all holding company debt of Progress would be assumed by Duke. Progress' utility subsidiaries would continue their current pattern of fixed-income financing on an individual basis.

Credit metrics at Progress for the LTM period ended Sept. 30, 2010 were consistent with 'BBB' IDR guidelines and company has no pending base rate cases. Progress' ratios of FFO/Debt and FFO interest coverage were approximately 18% and 4x, respectively, for the 12 month period ended Sept. 30, 2010. The relatively sizable debt at the parent holding company is a credit concern.

The rating affirmation of Carolina Power and Light Company (PEC) reflects its strong financial position and supportive state regulation. PEC's ratings also consider the upstream dividend payments to Progress needed to help support the substantial holding company debt (about 25% of Progress' consolidated debt). While helped by favorable weather, FFO interest coverage was more than 7x for the 12 months ended Sept. 30, 2010. Fitch anticipates PEC's credit metrics would remain strong relative to rating guidelines following closing of the merger. PEC faces execution risk in its fleet modernization plan

The rating affirmation of Florida Power Corp. (PEF) reflects moderating regulatory risk following a May 2010 base rate settlement that freezes base rates through 2012, effective clause recovery for environmental and nuclear capital spending, strong liquidity and manageable near term debt maturities. Favorably, the Florida PSC has permitted PEF to recover replacement power costs related to the extended nuclear outage at Crystal River 3 (subject to refund for prudence), and with repairs nearly complete, the unit is currently expected to re-enter service in the first quarter of 2011

Closing of the merger is subject to various contingencies including regulatory approvals from state utility commissions North Carolina and South Carolina, and approvals from the Federal Energy Regulatory Commission, U.S. Department of Justice, Nuclear Regulatory Commission and shareholders. The merger approval standard of the South Carolina Public

Service Commission is a 'net benefit' for customers, which is a higher standard than 'no harm'. The close of the merger is targeted for the fourth quarter of 2011

Fitch has affirmed the following ratings with a Stable Outlook:

Progress Energy, Inc.

--Long-term IDR at 'BBB';

--Senior unsecured debt at 'BBB';

--Short-term IDR at 'F2'.

Florida Power Corp.

--Long-term IDR at 'BBB+';

--First mortgage bonds at 'A';

--Senior unsecured debt at 'A-';

--Preferred securities at 'BBB';

--Short-term IDR/Commercial Paper (CP) at 'F2'.

FPC Capital One

--Preferred securities at 'BBB'.

Carolina Power & Light Co.

--Long-term IDR at 'A-';

--First mortgage bonds at 'A+';

--Senior unsecured debt at 'A';

--Preferred securities at 'BBB+',

--Short-term IDR/CP at 'F1'.

Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:

--'Corporate Rating Methodology', Aug. 16, 2010

--'Credit Rating Guidelines for Regulated Utility Companies' July 31, 2007

--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines' Aug. 22, 2007

--'Utilities Sector Notching and Recovery Ratings', March 16, 2010.

Applicable Criteria and Related Research.

Corporate Rating Methodology

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=546646

Credit Rating Guidelines for Regulated Utility Companies

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=334652

U S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=338030

Utilities Sector Notching and Recovery Ratings

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=504546

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MOODY'S
INVESTORS SERVICE

Rating Action: Moody's affirms Duke, Progress and subsidiary ratings following merger; outlooks stable

Global Credit Research - 03 Jul 2012

Approximately $33 billion of debt securities affected

New York, July 03, 2012 -- Moody's Investors Service affirmed the ratings and stable outlooks of Duke Energy Corporation (Duke: Baa2 senior unsecured, Prime-2 short-term rating for commercial paper) and its subsidiaries (listed below) as well as the ratings and stable outlooks of Progress Energy Corporation (Progress: Baa2 senior unsecured, Prime-2 short-term rating for commercial paper) and its subsidiaries (listed below) following the closing of the merger between the two companies. Duke is now the parent holding company of the combined Duke/Progress organization, although Progress will continue to exist as an intermediate holding company for utility subsidiaries Progress Energy Carolinas and Progress Energy Florida.

Moody's assigned a Baa2 senior unsecured rating to Duke Energy's unsecured bank revolving credit facility, which is in place and has been increased to $6 billion from $4 billion through a previously agreed upon arrangement with the banks to accommodate the merger with Progress.

Moody's affirmed the ratings and stable outlooks of Duke's utility subsidiaries, including Duke Energy Carolinas (Duke Carolinas - A3 senior unsecured), Duke Energy Ohio (Duke Ohio - Baa1 senior unsecured), Duke Energy Indiana (Duke Indiana - Baa1 senior unsecured), and Duke Energy Kentucky (Duke Kentucky - Baa1 senior unsecured).

Moody's also affirmed the ratings of Progress Energy's utility subsidiaries including Progress Energy Carolinas, Inc. (Progress Carolinas, A3 senior unsecured, Prime-2 short term rating for commercial paper) and Progress Energy Florida, Inc. (Progress Florida, Baa1 senior unsecured, Prime-2 short term rating for commercial paper). Moody's expects to withdraw the Prime-2 commercial paper ratings of Progress, Progress Carolinas, and Progress Florida on or about August 15, 2012 when all commercial paper outstanding at these entities has been redeemed.

RATING RATIONALE

"The rating affirmations of Duke and Progress reflect their strong and stable financial profiles, a higher proportion of regulated utility operations in Duke's overall business following the merger, and increased diversity among regulatory jurisdictions" said Michael G. Haggarty, Senior Vice President. "Although Moody's views the merger between the two companies as broadly credit neutral, it does improve the long-term strategic position of the Duke organization through the addition of a Florida service territory, generation dispatch efficiencies in the Carolinas, and the ability to spread fixed assets over a larger asset platform" added Haggarty. The combination increases the percentage of Duke's lower risk regulated business activities to roughly 85% of its total business from about 75% before the merger.

In affirming the ratings and stable outlooks, we note the change in CEO role that was announced at merger close and do not expect any material change in the strategic direction or financial policies of the company as a result of this development. The change does create some uncertainty over the longer-term leadership of the company, as the current Duke CEO had indicated a willingness to relinquish this role after many years to facilitate the merger with Progress. The CEO change could also lead to some additional turnover in the newly constituted company's senior management team, but we don't expect such developments by themselves to affect the company's ratings or rating outlooks.

We now view both Duke and Progress as more appropriately positioned at the Baa2 rating level. Whereas Duke had been more strongly positioned prior to the merger, the addition of a more highly leveraged Progress holding company to the Duke organization has slightly weakened its position within the Baa2 rating level. Conversely, Progress Energy's rating has long been constrained by $4 billion of debt at the holding company level. This debt will not be guaranteed by Duke and will continue to be supported and serviced by upstreamed dividends from both Progress Carolinas and Progress Florida. The combined Duke and Progress holding company debt as a percentage of total company debt will now be in the range of 25% and could rise further if additional debt is issued at the Duke parent company, up from approximately 20% pre-merger. Partly as a result of this additional leverage, we expect Duke's consolidated cash flow (CFO-pre WC) to debt metrics to fall to the mid to high teens range from above 20% historically, still adequate for a Baa2 rating but with less cushion.

The merger will create the largest utility system in the Carolinas, where the companies expect to generate $650 million of savings from fuel purchasing power and joint generation dispatch, although this will occur over a longer time frame than originally anticipated. The ratings affirmations and maintenance of stable outlooks for Duke Carolinas (A3 senior unsecured) and Progress Energy Carolinas (A3 senior unsecured) reflect the above average regulatory environments in both North and South Carolina, credit supportive cost recovery provisions in place, strong cash flow coverage metrics, and service territories that should experience modest growth over the intermediate term. Although the merger is not expected to significantly alter the utilities' respective capital expenditure programs or planned generation retirements, joint dispatch arrangements should benefit both utilities and could eventually slow the timing of some new generation. In addition, because of the relatively early enactment of North Carolina's 2002 Clean Smokestacks Act, both Duke Carolinas and Progress Energy Carolinas are fairly well positioned to meet currently mandated environmental requirements.

The rating affirmation and stable outlook of Duke Indiana (Baa1 senior unsecured) reflects strong and stable financial metrics for its rating, good cost recovery mechanisms in place, and a regulatory framework that continues to be relatively supportive despite the substantial cost overruns and associated controversy surrounding the utility's Edwardsport IGCC Project. These credit strengths have largely offset the negative impact that the April 30 project cost recovery settlement agreement, if approved, will have on the utility. The settlement capped recovery of Edwardsport costs at $2.6 billion, well below the $3.3 billion of currently estimated costs, and not significantly above the $2.35 billion of cost recovery that had been previously approved by the Indiana Utility Regulatory Commission. The settlement also requires that the utility not increase base rates until April 2014, although financial metrics should be supported by riders and cost recovery provisions related to Edwardsport, which should become effective this year if the settlement is approved. The settlement caused the company to recognize a pretax charge of $420 million in the first quarter of 2012, in addition to the $220 million charge previously taken in the third quarter of 2011. Although these charges are credit negative, the settlement does allow Duke Indiana to begin to move beyond the controversy associated with the construction of the plant while preserving a reasonably supportive regulatory framework in Indiana.

The rating affirmation and stable rating outlook of Duke Ohio (Baa1 senior unsecured) considers financial metrics that are currently adequate for its Baa1 rating, although they could be pressured by provisions included in its current three year Electric Security Plan (ESP) approved in November 2011. The ESP requires Duke Ohio's generation requirements to be procured through a competitive bid process and requires the utility to transfer its non-regulated generating assets to an affiliate or subsidiary by the end of 2014. While the ESP provides for a $330 million non-bypassable electric service stability charge which will offset some of the negative pressure on financial metrics, we expect the ESP to result in lower revenues, earnings, and cash flow from the utility's coal fired generation assets. We will closely monitor the company's progress on transferring its non-regulated generation assets to an affiliate and ultimately separating them from its transmission and distribution business, as well as its financial performance in an increasingly competitive Ohio generation environment. We anticipate any restructuring of Duke Ohio to conform with the provisions of the ESP will be done in a manner that is supportive of its current rating.

The ratings affirmation and stable outlook of Duke Kentucky (Baa1 senior unsecured) reflects its comparatively low business risk profile and the credit supportive regulatory environment in Kentucky, despite a two year rate freeze currently in place. The company exhibits strong financial metrics which, although likely to decline somewhat because of the rate freeze and higher spending for environmental compliance, should remain adequate for its current Baa1 rating.

The ratings affirmation and stable outlook of Progress Energy Florida (Baa1 senior unsecured) is prompted by its recently executed comprehensive Florida rate settlement that provides some regulatory clarity as the utility approaches the end of its current rate agreement on December 31, 2012, as well as a stabilized political and regulatory environment for utilities in Florida. Positively, the settlement provides for higher base rates, recovery on a deferred basis of its Levy new nuclear construction project costs, and an authorized return on equity of 10.5%. However, it also requires the utility to refund of $288 million of replacement fuel and purchased power repair costs incurred from its lengthy Crystal River 3 nuclear plant outage. Crystal River 3 will also be removed from rate base until it resumes commercial operation. Among the key uncertainties the settlement did not address are the cost and schedule to repair the plant and the ultimate amount of insurance proceeds the company will receive from the mutual nuclear insurer Nuclear Electric Insurance Limited (NEIL), which we should receive greater clarity on later this year. Although the merger will not result in any direct benefits to

Progress Florida similar to the expected joint dispatch benefits in the Carolinas, the utility will be part of a much larger and more diverse organization in the event it returns Crystal River to service or moves forward with currently postponed plans for new nuclear generation in Florida.

Ratings assigned include:

Duke Energy senior unsecured bank credit facility at Baa2.

Ratings affirmed include:

Duke Energy's Baa2 senior unsecured and Issuer Rating and Prime-2 short term rating for commercial paper;

Duke Energy Carolinas A1 senior secured, A3 senior unsecured and Issuer Rating;

Duke Energy Indiana's A2 senior secured, Baa1 senior unsecured and Issuer Rating;

Duke Energy Kentucky's Baa1 senior unsecured;

Duke Energy Ohio's A2 senior secured and Baa1 senior unsecured and Issuer Rating;

Progress Energy's Baa2 senior unsecured and Prime-2 short-term rating for commercial paper,

Carolina Power & Light Company d/b/a Progress Energy Carolinas A1 senior secured, A3 senior unsecured and Issuer Rating, Baa2 preferred stock, and Prime-2 short-term rating for commercial paper,

Florida Power Corporation d/b/a Progress Energy Florida's A2 senior secured, Baa1 senior unsecured and Issuer Rating; Baa3 preferred stock, and Prime-2 short-term rating for commercial paper

Florida Progress Funding Corporation's Baa2 junior subordinated debt;

FPC Capital I's Baa2 preferred stock.

The principal methodology used in rating these issuers was the Regulated Electric and Gas Utilities rating methodology published in August 2009. Other methodologies and factors that may have been considered in rating these issuers can be found on Moody's website.

Duke Energy Corporation is a holding company for regulated utilities Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky, as well as international business activities in Central and South America. Progress Energy, Inc. is an intermediate holding company of Duke Energy and a holding company for Progress Energy Carolinas, Inc., and Florida Power Corporation d/b/a Progress Energy Florida, Inc Duke Energy is headquartered in Charlotte, North Carolina.

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STANDARD & POOR'S
RATINGS SERVICES

January 10, 2011

Research Update:

Duke Energy 'A-' Rating Affirmed And Progress Energy 'BBB+' Rating Placed On Watch Positive On Planned Merger

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Research Update:

Duke Energy 'A-' Rating Affirmed And Progress Energy 'BBB+' Rating Placed On Watch Positive On Planned Merger

Overview

- Duke Energy Corp. and Progress Energy Inc. have agreed to merge through a stock-for-stock transaction and assumption of existing debt.
- We are placing the 'BBB+' corporate credit and issue ratings on Progress Energy Inc., Carolina Power & Light Co. (dba Progress Energy Carolinas Inc.), and Florida Power Corp. (dba Progress Energy Florida Inc.) on CreditWatch with positive implications to reflect the likely upgrade following the completion of the transaction.
- We are affirming the 'A-' ratings on Duke Energy Corp. and the outlook remains stable. Duke is expected maintain credit quality through the merger-approval process and could show financial improvement post merger depending on the terms of the regulatory approvals and the success of integration efforts.
- The combined entity would have an excellent business risk profile, with a primary focus on regulated electric utility operations, and a significant financial risk profile.

Rating Action

On Jan. 10, 2011, Standard & Poor's Ratings Services placed its 'BBB+' corporate credit ratings on Progress Energy and its subsidiaries, Progress Energy Carolinas and Progress Energy Florida, on CreditWatch with positive implications. In addition, we affirmed the 'A-' corporate credit rating on Duke Energy and its subsidiaries, Duke Energy Carolinas LLC, Duke Energy Ohio Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky Inc. The rating actions follow the announcement that Progress Energy has entered into an agreement to merge with Duke Energy. Duke Energy will be the surviving entity. Completion of the merger is possible by the end of 2011 following approvals from the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the Department of Justice, and North Carolina and South Carolina regulators.

The positive CreditWatch listing on Progress Energy and its subsidiaries reflects that the company's credit quality will benefit from the merger with the higher-rated Duke Energy. The ratings affirmation on Duke Energy reflects our expectation that the combined entity will have an 'A-' corporate credit rating, based on excellent business risk profile and significant financial risk profile. The premium to be paid to Progress shareholders, which we calculate to be about 33% to book value, has a reasonable chance to be recouped through the retention of merger synergies. No additional debt is contemplated as part of the transaction, and regulatory approvals are expected to be timely and credit-supportive given the limited number of jurisdictions involved and the merger synergies available to show benefits to ratepayers.

Both companies are focused on regulated electric utility operations, and we expect the consolidated business risk to remain excellent. The consolidated business risk profile incorporates the following factors:

- A very large customer base of more than 7 million customers spread over six states, providing superior operating and regulatory diversity.
- The states in which the combined entity will operate are viewed as having regulatory environments in the "more credit supportive" or "credit supportive" categories.
- More than 80% of the combined company's credit profile would be characterized as very low-risk, domestic, regulated electric utility operations. The balance is derived from Duke Energy's international operations in South America and merchant activities that include a small generation fleet in the Midwest, wind power investments, and retail energy marketing.
- Total generation capacity will exceed 57,000 megawatts (MW), with about 85% of that capacity being either scrubbed, non emitting, or having lower emissions. The remainder will present the combined entity with opportunities to retire older power plants and replace them with newer units, thereby growing rate base.

Standard & Poor's expects the combined entity to have a financial risk profile that will be in the significant category, demonstrating some weakness in the first year after the merger, but rebounding in subsequent years as a result of realizing cost savings and implementing base rate increases to recovery invested capital. Therefore, we would expect that post merger adjusted funds from operations (FFO) to total debt to average about 15%, adjusted FFO interest coverage to average 3.75x, and adjusted debt leverage to be about 52%. Consolidated liquidity should also remain adequate since both companies will preserve their existing revolving credit facilities that total $5.3 billion.

Rationale

The ratings on Duke Energy reflect the consolidated credit profiles of its operating subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana, Duke Energy Kentucky, the contribution of the company's Latin American operations, and existing and planned renewable generation investments. Ratings also reflect the projected credit profile of Duke Energy after it merges with Progress Energy. The ratings on Progress Energy reflect the consolidated credit profiles of its wholly owned subsidiaries, Carolina Power & Light Co. (dba Progress Energy Carolinas Inc, PEC) and Florida Power Corp. (dba Progress Energy Florida, Inc. PEF), and the prospect of merging with the higher-rated Duke. Progress Energy has an excellent business risk profile that reflects stable regulated electric utility operations in North and South Carolina and Florida. Duke Energy's excellent business risk profile is characterized by stable regulated utility operations in the Carolinas, Ohio, Kentucky, and Indiana. The company's operations in Latin America consist of about 4,000 MW of generation capacity. Duke is planning to expand its portfolio of wind and solar generation investments, currently at about 730 MW, which are viewed as having higher business risk compared with the regulated utility operations.

Duke Energy's large and diverse U.S. regulated utility operations serve customers in the Carolinas and the Midwest. The utilities operate under generally credit-supportive regulatory environments that provide for slightly below-average returns and timely recovery of fuel and other variable costs. The utility operations benefit from operating diversity in five different states, and demographic and economic diversity in service territories that range from average to attractive. The utilities have strong generation operations with high availability and capacity utilization factors. Rates are competitive for the regions of operations and provide some cushion for future rate increases and fuel cost recoveries. These strengths are offset by a significant capital spending program that will total up to $15 billion through 2012, with about 80% of that targeted for regulated utility projects. The capital spending program is large, will necessitate additional debt issuance, and will require regular base rate increases to incorporate the new generation assets into rate base. As a result, ongoing effective management of regulatory risk that produces improving regulatory returns will be very important to support credit quality.

Duke Energy Ohio's electric security plan (ESP) went into effect in January 2009 and succeeded the earlier rate stabilization plan. The ESP plan, which expires at the end of 2011, provides for staggered base generation rate increases of $36 million in 2009, $74 million in 2010, and $98 million 2011 to compensate the company for dedicating about 4,000 MW of generation assets to serve native load. The ESP plan also includes trackers for fuel, purchased power and capacity costs, and environmental expenditures, avoiding the need for any deferrals, as well as recovery of non-bypassable charges related to new generation, if such projects are approved by the regulator. Since the ESP was implemented, customer and margin losses due to greater competitive forces and low market prices for generation in Ohio have eroded financial results and indicate that business risk has risen in the state. The company's ability to manage the competitive environment for the next few years and its strategic decisions surrounding the terms of the regulatory compact in Ohio in after 2011 could affect credit quality over the long term.

Cost increases in Indiana related to the construction of the 630 MW Edwardsport coal plant could also have credit quality implications, as Duke attempts to buttress its ability to eventually reflect the higher costs in rates through the regulatory process. The integrated gasification combined cycle (IGCC) generating station offers potential environmental and efficiency advantages over conventional coal-fired plant technology, but it has not been constructed on this scale and has proven to be an engineering and financial challenge. Estimated costs to complete the project have risen significantly (almost 50%), and only a portion of the overruns have been formally reviewed and effectively deemed prudent. If Duke is compelled to accept more risk to complete the project, its proficiency in managing that risk will be an important element in assessing its creditworthiness. A recent decision by the parties to renegotiate a settlement on Edwardsport construction and cost recovery could yet have credit implications. Public perception of the settlement, which requires approval by Indiana regulators, may have been affected by recent revelations of interactions between regulators and the utility that have led to dismissals or resignations of several utility executives and regulators. Credit quality would only be impaired if a new settlement or a regulatory decision shifted significant risks to Duke as a condition to completing the plant, and Duke decides to proceed with construction on that basis.

Standard & Poor's ascribes higher business risk to Duke's international operations due to the uncertainty of the local political and regulatory environments in the countries where it operates, especially Brazil, Peru, and Argentina. The Latin American assets have been self funding, and no cash flow from overseas is factored into our analysis of Duke's ability to service the U.S. rated debt. Any substantial capital spending at the international operations could have ratings implications, depending on the risk profile of the spending. Duke is also pursuing the expansion of its wind generation business that is expected to be financed in a credit-neutral manner and under a model that minimizes market risk through long-term contracts with suitable counterparties. Any acceleration in the growth of this segment could also affect ratings.

Duke's consolidated financial risk profile is in the significant category and is expected to remain in that category after the merger. While recent historical credit metrics have been strong, in part reflecting low debt leverage, the financial profile is expected to weaken modestly over the intermediate term given the company's large capital spending program and the proposed merger. Because the associated cash flow generation will lag capital spending until several generation projects currently under construction are included in rate base, credit protection measures will weaken from 2010 levels, albeit at levels that should still support the current ratings. Adjusted debt leverage is expected to be at or below 50% and adjusted FFO to total debt to be between 15% and 20% to support current ratings.

Progress has a large and diverse customer base, serving more than 3.1 million customers. While the customer base has historically demonstrated consistent growth of more than 2% annually, the recession has slowed customer growth especially in Florida where the total number of customers declined slightly in 2009. Total generating capacity consists of more than 22,000 MW. On a consolidated basis, residential and commercial customers account for about 63% of sales, industrial customers for 15%, and wholesale customers for 20%. Wholesale sales are generally under long-term contracts with various public power, cooperative, and investor owned utilities, regulated by the FERC on a cost of service basis, and lack fuel cost deferrals.

Progress Energy Carolinas and Progress Energy Florida have managed their regulatory relations effectively, achieving timely recovery of fuel and capital expenditures, and storm and environmental costs. In addition, Florida's 2006 comprehensive energy legislation provides support for new generation including nuclear plants. North Carolina passed legislation in July 2009 that expedites the certification process for new gas-fired power plants as long as existing coal plants at the current site are retired. Progress Energy Carolinas is in the process of building three new combined cycle gas turbine units: the 600 MW Richmond facility with an in-service date of June 2011, the 950 MW Wayne County facility expected to operate in January 2013, and the 620 MW New Hanover County facility expected to operate in early

2014. Despite political overtones that have somewhat increased regulatory risk in Florida, the regulatory environment continues to be reasonably constructive mainly through the use of various clauses that allow for recovery of approved capital expenditures, including environmental expenditures, and fuel. In June 2010, the Florida regulators approved a settlement for Progress Energy Florida that effectively maintains current base rates through 2012 without affecting the various clauses mentioned earlier, while still providing for an ROE of 9.5%-11.5%. The settlement also provides that if the earned ROE falls below 9.5%, Progress Energy Florida may seek rate relief after it has used at least $150 million of the allowed depreciation reserve in the relevant period.

Progress Energy Florida is completing the work to bring the Crystal River 3 (CR3) nuclear plant back on line. CR3 experienced delamination within the concrete of the outer wall of the containment structure during a normal refueling and maintenance outage in September 2009. As of Sept. 30, 2010, Progress Energy Florida had incurred $237 million in replacement power costs, with $63 million already recovered from insurance proceeds, $49 million still to be received from insurance, and $125 million deferred for recovery through clauses. Repair costs totaled $117 million, with $18 million received from insurance, $75 million still to be received from insurance, and the balance to be deferred for base rate recovery. In October 2010, Progress Energy Florida received approval from the Florida regulators to establish a separate docket related to the outage and replacement fuel and power costs associated with the extended outage.

Consolidated capital spending will continue to be significant over the next few years, necessitating additional borrowings, to address environmental compliance, new generation, uprates at existing plants, and system growth and maintenance needs. Total capital spending is expected to be about $2.2 billion in 2011 and $1.9 billion in 2012. Given the completion of environmental projects in Florida and the new generation projects in North Carolina, the capital spending program will be geared in favor of the Carolina operations on a 65%-35% basis. Progress has an aggressive financial risk profile. For the 12 months ended Sept. 30, 2010, financial performance benefited from some stabilization and/or improvement in the local economies as well as favorable weather. The financial performance has slightly exceeded our base case expectations with adjusted FFO of $2.5 billion and adjusted total debt of $14.8 billion, leading to adjusted FFO interest coverage of 3.5x, adjusted FFO to total debt of 16.8%, and adjusted debt leverage of 59.3%.

Short-term credit factors

The short term rating on Duke Energy is 'A-2' and largely reflects the company's long term corporate credit rating and the stable regulated utility operations that generate the bulk of cash flows. Liquidity is adequate under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors. Adequate liquidity supports Duke's 'A-' credit rating. Projected sources of liquidity, mainly operating cash flow and available bank lines, exceed projected uses, mainly necessary capital expenditures, debt maturities, and common dividends, by more than 1.2x. Duke's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and generally prudent risk management further support our description of liquidity as adequate.

Duke Energy's debt maturities total about $600 million in 2011. The company has a $3.14 billion master revolving credit facility maturing in 2012 with approximately $2.5 billion currently available. The master credit facility contains a sub-limit of $1.1 billion for Duke Energy, $840 million for Duke Energy Carolinas, $650 million for Duke Energy Ohio, $450 million for Duke Energy Indiana, and $100 million for Duke Energy Kentucky.

Progress Energy's liquidity is adequate under Standard & Poor's corporate liquidity methodology, which describes a company's liquidity in five standard categories. Progress Energy's liquidity supports its 'BBB+' corporate credit rating. Projected sources of liquidity--mainly operating cash flow and available bank lines--cover projected uses, mainly necessary capital expenditures, debt maturities, and projected common dividends, by about 1.2x over the next 12 months. The short term rating on Progress is 'A-2', reflecting the company's corporate credit rating and its stable cash-generating capability.

As of Oct. 15, 2010, the consolidated lines of credit totaled $2 billion, with $750 million available at each of the utility operating subsidiaries (fully available at PEC and PEF) and expiring in October 2011, and $500 million available at the holding company with $468 million still undrawn and expiring in May 2012. None of the bank facilities have rating triggers. Progress Energy also had $691 million in cash and short-term investments. There is $1 billion in debt maturities in 2011, and $950 million in 2012.

CreditWatch

The positive CreditWatch on Progress Energy is based on the anticipated consummation of the merger with the higher-rated Duke.

Outlook

The outlook on Duke Energy is stable and reflects Standard & Poor's projection of steady financial performance while the company successfully completes the merger with Progress Energy and its considerable construction projects without further delays or cost increases. We could lower ratings or institute a negative outlook if credit protection measures unduly weaken or if adverse developments in Indiana or Ohio lead to a conclusion that business risk has worsened. A decision to proceed with the merger even if conditions enacted by regulators in the approval process undermine the financial basis for the transaction would also lead to lower ratings. The outlook could be revised to positive if the merger is completed with financial parameters intact, and if the large capital program is successfully completed and is not extended by new spending, especially on nuclear generation.

Related Criteria And Research

- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, published May 27, 2009.
- 2008 Corporate Criteria: Analytical Methodology, published April 15, 2008.

Ratings List

Ratings List

	To	From
Progress Energy Corp.		
Corporate Credit Rating	BBB+/CW Pos/A-2	BBB+/Stable/A 2
Carolina Power & Light Co. dba Progress Energy Carolinas Inc.		
Corporate Credit Rating	BBB+/CW-Pos/A-2	BBB+/Stable/A 2
Florida Power Corp. dba Progress Energy Florida Inc.		
Corporate Credit Rating	BBB+/CW Pos/A-2	BBB+/Stable/A 2
Duke Energy Corp.		
Corporate Credit Rating	A /Stable/A-2	A /Stable/A 2
Duke Energy Carolinas LLC		
Corporate Credit Rating	A-/Stable/A-2	A /Stable/A-2
Duke Energy Ohio, Inc.		
Corporate Credit Rating	A-/Stable/A-2	A /Stable/A-2
Duke Energy Indiana, Inc.		
Corporate Credit Rating	A-/Stable/A-2	A /Stable/A-2
Duke Energy Kentucky, Inc.		
Corporate Credit Rating	A-/Stable/	A-/Stable/--

Complete ratings information is available to RatingsDirect subscribers on the Global Credit Portal at www.globalcreditportal.com and RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Fitch Ratings

Fitch Places Southern on Negative Watch & AGL on Positive Watch Following Acquisition Announcement

Fitch Ratings-New York-24 August 2015: Fitch Ratings has placed the 'A' long-term Issuer Default Rating (IDR) and senior unsecured debt ratings of The Southern Company (Southern) on Rating Watch Negative. The actions follow today's announcement of a definitive agreement to acquire AGL Resources (AGL) for $8 billion in cash.

Southern should benefit from the greater scale and diversity from the addition of predominantly low-risk natural gas distribution businesses. However, these benefits will be partially offset by the increase in the company's near-term leverage given the primarily debt driven acquisition financing and a measured pace of deleveraging through 2019.

Prior to today's action, Southern's Rating Outlook was Negative. The ratings of Southern's subsidiaries are unaffected by this transaction.

Fitch has also placed AGL's 'BBB+' long-term IDR on Rating Watch Positive. Fitch will likely maintain a one-notch differential between the IDRs of Southern and AGL. Post-closing, AGL will become a second-tier holding company of Southern and will remain as the direct parent of its two operating utilities, Atlanta Gas Light Co. (AGLC; 'BBB+' IDR), and Northern Illinois Gas Company (Nicor Gas; 'A'). Given the close parent subsidiary rating linkages, Fitch has placed AGLC's IDR on Rating Watch Positive as well. Fitch has affirmed the IDR of Nicor Gas with a Stable Outlook. Fitch expects Nicor Gas' credit metrics to remain strong for its rating category with sufficient headroom to absorb potential regulatory concessions required for merger approval.

Southern is planning to acquire AGL for $8 billion in cash or $66 per share, which implies a 38% premium over the closing price on Aug. 21, 2015. The cash offer will be predominantly financed with debt at close, but permanent financing is expected to include $3 billion of equity issuances that start in fourth quarter of 2015 and run through 2019. Including assumed debt of approximately $4 billion, the transaction value is $12 billion or 11x AGL's LTM June 30 EBITDA.

KEY RATING DRIVERS

Southern

Majority Debt Funding of the Acquisition: The proposed acquisition results in a meaningful increase in consolidated leverage compared to Southern's current and projected stand-alone financial condition. The rise in leverage is driven by the combination of the acquisition debt to be issued by Southern, the assumption of existing AGL consolidated debt and a measured pace of deleveraging to reach a permanent acquisition financing mix of 63% debt and 37% equity by 2019. Fitch expects consolidated cash flow leverage and fixed charge coverage metrics of the combined entity to meaningfully weaken in the short to medium term compared with Southern's stand-alone credit profile. Based on a preliminary analysis and excluding benefits of any potential synergies, Fitch forecasts pro forma adjusted FFO leverage to be in the 4.5x - 5.0x range and FFO fixed charge coverage in the 4.5x - 4.75x range over the forecast period.

Improved Business Profile: The acquisition of AGL marginally reduces Southern's risk profile, in Fitch's view. Fitch generally views gas distribution businesses as low risk and AGL's utilities are generally well managed with numerous supportive regulatory mechanisms in place. AGL's minority investments in interstate pipelines carry moderately higher competitive market risks, but these are offset to a large extent by long-term offtake agreements with creditworthy counterparties. While the non-regulated retail and wholesale businesses of AGL are volatile, the exposure is somewhat contained given these will be a small part of the combined company.

Southern gains tremendous scale and geographic diversity with the acquisition and its inaugural pursuit of natural gas businesses can smooth out earnings and cash flow of its predominantly summer peaking electric utilities. The combination also lowers the contribution of its non-regulated, albeit conservatively managed, Southern Power Company in the overall business mix as well as that of its utility subsidiary, Mississippi Power Company, which is undergoing significant stress related to the construction cost overruns and inadequate rate recovery for the Kemper Integrated Gasification Combined Cycle (IGCC) project.

New States and Businesses Induce Uncertainty: Fitch's concerns primarily lie with Southern's first regulatory foray outside the southern states. Southern will add five new state regulatory jurisdictions, which includes some tough jurisdictions such as Illinois and New Jersey.

Regulatory Approvals: Apart from AGL shareholders approval, state regulatory approvals are required in Georgia, Illinois, New Jersey, Maryland and Virginia. The transaction is also subject to clearance under the Hart-Scott Rodino Antitrust Improvements Act. Southern expects to close this deal in the third quarter of 2016.

Resolution of the Rating Watch: Fitch expects to resolve the Rating Watch either at or close to the transaction completion, which will take approximately 12 months. The regulatory approval process and the pace of equity issuance by Southern will be the key data points to monitor. In parallel, Fitch will continue to track the progress of the Kemper IGCC project, which includes successful completion (currently estimated in first half of 2016) and operations of the plant, resolution of regulatory uncertainty in Mississippi (order on the permanent rate recovery for the in service portion of the plant scheduled for early December 2015) and issuance of approximately $1 billion in securitization proceeds at Mississippi Power Company (Fitch's expectation is early 2017). Fitch will also track the construction progress of the Vogtle 3 and 4 units by Georgia Power Company based on the current costs and schedule and continuation of regulatory support in Georgia as demonstrated through future Vogtle Construction Monitoring proceedings and the next general case to be filed in mid 2016.

AGL

Enhanced Scale and Financial Flexibility: AGL's existing 'BBB+' IDR takes into consideration the low-risk profile of AGL's utility operations which represents approximately 70% of the consolidated earnings. The Rating Watch Positive reflects the financial and operational benefits from becoming part of Southern. Besides improved scale and likely synergy savings, Fitch believes that this transaction will particularly benefit AGL's aggressive pursuit of pipeline projects and provide more diverse funding sources. AGL has announced definitive plans to participate in three pipeline projects totaling nearly $700 million in investments supplying its gas customers in Georgia, New Jersey and Virginia. The majority of the pipeline capacities are contracted to highly rated utilities. The projects are expected to complete in the 2017 and 2018 timeframe. The company also completed a non-binding open season for the proposed [illegible] State Pipeline which would serve customers in Illinois. Although these projects appear to expand its midstream footprint, high level of contractual commitment and expected balanced financing structure help neutralize the competitive market risks.

Manageable Non-Utility Exposure: While results from the non-utility businesses are volatile, the exposure is somewhat contained given their relatively small contribution to the combined entity.

Rating Linkages Between AGLC and AGL: AGLC's ratings reflect its close linkage to AGL. The linkage is driven by AGLC's reliance on AGL for access to capital and liquidity, and AGL's dependence on upstream dividends from AGLC to service holding company-level debt. All AGL's subsidiaries except Nicor Gas participate in a corporate money pool arrangement for short-term borrowing needs. Georgia's regulatory framework does not limit AGLC's ability to upstream dividends to AGL.

Nicor Gas's Ratings Unaffected: Fitch has affirmed the ratings and Stable Outlook for Nicor Gas. Fitch believes any synergy benefit will likely be small for Nicor Gas due to the lack of geographic overlap with Southern's utility subsidiaries. Additionally, Illinois has a history of political interference with merger approvals and typically imposes rate freezes. Fitch believes Nicor Gas' credit metrics are strong enough to withstand likely merger concessions in the approval process.

Resolution of Rating Watch: Although Fitch acknowledges the strategic and financial benefit for AGL as a result of the transaction, the [illegible] at AGL will also depend upon the resolution of Southern's Negative Rating Watch to ensure that proper rating differential between AGL and Southern is maintained. As previously stated

12/4/2015 [illegible]

Fitch intends to [illegible] AGL.

KEY ASSUMPTIONS

Fitch's key assumptions within the rating case for Southern [illegible]:

[illegible] AGL acquisition;
[illegible] of $3 billion in [illegible] 2015 [illegible] 2019 [illegible];
- At Alabama Power Company [illegible] Rate [illegible] & [illegible] over 2016 - 2017, [illegible] environmental [illegible] 2015 and [illegible] 2016 and 0.5% increase in electricity sales in 2016 and [illegible];
- At Georgia Power Company, [illegible] Nuclear Construction Cost Recovery (NCCR) tariff [illegible] over 2015 - 2017 [illegible] Gulf Power Company [illegible] 2016 and 1% in 2017 [illegible] rate order;
- At Mississippi Power Company [illegible] Kemper [illegible] through regulated rates, [illegible] rate [illegible] January 2017 [illegible] operation date (COD) by June 2016 [illegible] (ECO) [illegible] over 2016 - 2017, [illegible] 2016-2017;
At Southern Power Company [illegible] and [illegible] funding of growth capex.

Fitch's key assumptions within the rating case for AGL are as follows:

AGL
- Capex spending at utilities averages approximately $3?? million from 2015 through 2018;
[illegible] $100 million per year [illegible] pipeline [illegible] projects;
[illegible] of total capex [illegible] nearly 80% from 2015 through 2018;
- Dividends [illegible] from 2015 [illegible] 2017.

RATING SENSITIVITIES FOR SOUTHERN

Positive: Future developments that may, individually or collectively, lead to a positive rating action include:

[illegible] FFO adjusted leverage [illegible] below 4.0x;
[illegible] costs [illegible] by [illegible] performance;
[illegible] Power Company's pending rate filings;
[illegible] cost and/or schedule [illegible] to the overall project costs [illegible] by the Georgia PSC;
[illegible] 2016.

Negative: Future developments that may, individually or collectively, lead to a negative rating action include:
[illegible] in excess of those assumed in the financial forecasts [illegible] in equity issuance could have an adverse effect on ratings;
Significant [illegible] and/or Kemper projects [illegible] the recovery of those costs;
FFO adjusted leverage [illegible] to 4.5x or higher on a sustained basis.

RATING SENSITIVITIES FOR AGL AND SUBSIDIARIES

AGL, AGL Capital and AGLC

Positive: Future developments that may, individually or collectively, lead to a positive rating action:

[illegible] AGL Capital [illegible] upgraded, if Southern Company's IDR is [illegible] at A.

Negative: Future developments that may, individually or collectively, lead to a negative rating action include:

[illegible] expansion [illegible] businesses;
[illegible] the states that AGL's utilities operate [illegible] material concessions for merger approval;
AGL's adjusted debt/EBITDA above [illegible] 75x and/or FFO [illegible] below 3.75x on a sustained basis.

[illegible] Gas

Positive: Future developments that may, individually or collectively, lead to a positive rating action include:

[illegible] Gas Company [illegible]

Negative: Future developments that may, individually or collectively, lead to a negative rating action include:

[illegible]

FULL LIST OF RATING ACTIONS

Fitch [illegible] the following ratings [illegible]:

Southern Company
- Long-term IDR [illegible];
- Short-term IDR [illegible];
[illegible];
[illegible] 'A'.

Fitch has placed the following [illegible]:

AGL Resources Inc.
- [illegible] BBB+;

AGL Capital Corp. [illegible]
[illegible] 'BBB+'.

--Commercial paper 'F2'.

Atlanta Gas Light Company
--IDR 'A-';
--Senior unsecured medium-term notes 'A-'.

Fitch has affirmed following ratings with Stable Outlook:

Nicor Gas
--IDR at 'A';
--Senior unsecured notes at 'A+';
--First mortgage bonds at 'AA-';
--Short-term IDR at 'F1';
--Commercial paper at 'F1'.

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Date of Relevant Rating Committee: Aug. 24, 2015

Additional information is available on www.fitchratings.com

Applicable Criteria
Corporate Rating Methodology - Including Short-Term Ratings and Parent and Subsidiary Linkage (pub. 17 Aug 2015)
(https://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=869362)

Additional Disclosures
Dodd-Frank Rating Information Disclosure Form (https://www.fitchratings.com/creditdesk/press_releases/content/ridf_frame.cfm?pr_id=989868&cft=0)
Solicitation Status (https://www.fitchratings.com/gws/en/disclosure/solicitation?pr_id=989868)
Endorsement Policy (https://www.fitchratings.com/jsp/creditdesk/PolicyRegulation.faces?context=2&detail=31)

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades Southern Company to Baa2 stable; affirms subsidiary ratings and outlooks

Global Credit Research - 13 May 2016

Approximately $4 billion of debt downgraded

NOTE.On May 10, 2016, the press release was corrected as follows: In the debt list, the seniority of the Wilsonville (Town of) AL, I.D.B. revenue bonds was changed to Senior Unsecured from Senior Secured. Revised release follows.

New York, May 13, 2016 -- Moody's Investors Service downgraded the long-term senior unsecured rating of The Southern Company to Baa2 from Baa1 and affirmed Southern's Prime-2 short-term rating for commercial paper. The rating outlook is stable. Moody's affirmed the ratings and outlooks of Southern's subsidiaries: Alabama Power Company (A1 stable), Alabama Power Capital Trust V (A2 stable); Georgia Power Company (A3 stable), Gulf Power Company (A2 stable), Mississippi Power Company (Baa3 negative); Southern Electric Generating Company (A2 stable), and Southern Company Funding Corporation (Prime-2 stable).

RATING RATIONALE

"The downgrade of Southern is prompted by the primarily debt financed acquisition of AGL Resources, Inc. (AGL, unrated) which will increase parent company leverage and reduce cash flow coverage metrics", said Michael G. Haggarty, Associate Managing Director. The addition of approximately $8 billion of debt at the Southern holding company will increase parent level debt from around $4 billion currently or 12-13% of total consolidated debt to the $12 billion range, around 25% of consolidated debt, pressuring cash flow coverage metrics. "We project Southern's consolidated CFO pre-working capital to debt ratio will fall to approximately 15% immediately following the acquisition, from the 20% range currently, and not recover to previous levels for several years" added Haggarty.

The AGL acquisition comes at a time when Southern credit quality and relative position at the previous Baa1 rating level had already been weakened by over $2 billion of pre-tax charges related to cost increases and delays at the Kemper Integrated Gasification Combined Cycle power plant at Mississippi Power. Southern continues to provide critical support to Mississippi Power, with $778 million of promissory notes outstanding to the utility to maintain its liquidity until a permanent Kemper cost plan is approved and implemented. In addition, Southern's largest utility, Georgia Power is in the midst of an expensive, multi-year new nuclear plant construction program at its Vogtle nuclear plant site that has experienced cost increases and delays, with commercial operation currently three years behind schedule.

For Southern, the addition of approximately $8 billion of debt at the parent company will eliminate an important credit advantage that had distinguished Southern from many of its peers, namely, the limited use of holding company leverage and higher financial flexibility at the parent company. With 25% of the company's total consolidated debt at the holding company level going forward, structural subordination will increase and financial flexibility will diminish. Although Southern still has a lower percentage of debt at the parent company than some other Baa rated peers like Duke Energy Corporation (Baa1 negative) which will be at around 35% following the Piedmont Natural Gas Company, Inc. (A2 stable) acquisition; Dominion Resources, Inc. (Baa2 stable) at approximately 48% after its acquisition of Questar Corporation (Prime-1, ratings on review for downgrade); and NextEra Energy, Inc. (Baa1 stable), which guarantees 33% of its total reported consolidated debt; it is no longer a material factor differentiating Southern from those companies.

In AGL, Southern is acquiring an entity whose financing subsidiary, AGL Capital Corporation (guaranteed by AGL), is rated Baa1 stable, lower than three of Southern's four existing utility subsidiaries. Although AGL provides Southern with regulatory and operational diversity, it will generate lower financial coverage metrics than Southern or any of its subsidiaries currently does, with AGL's CFO pre-working capital to debt expected to decline to the low to mid-teens (from the mid to high teens historically) as it issues debt to fund planned capital investments, another reason for the downgrade of Southern.

The affirmation of the ratings of Southern's other subsidiaries Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, Southern Electric Generating, and Southern Company Funding reflects the minimal impact that Southern's acquisition of AGL will have on the credit profile of these companies. AGL is expected to be a separate subsidiary operating under the parent company. Although Southern will be servicing a substantial amount of new debt at the parent, potentially requiring a higher level of dividends from these other subsidiaries, the magnitude should not be enough to materially affect the individual subsidiary credit profiles or ratings. Each of Southern's major subsidiaries maintains their own bank facilities and liquidity sources and, with the exception of Mississippi Power, are not reliant on the parent for material financing, liquidity, or other needs.

The affirmation of the ratings and stable outlook of Alabama Power (A1) reflects the credit supportive regulatory environment in Alabama, a lack of capital expenditures for new generation over the next few years, and strong, stable financial metrics, albeit slightly below the our rating methodology guidelines for a high "A" rating with a three year average CFO pre-working capital to debt of 25.5%. Although there is a now a relatively wide four notch differential between the ratings of Alabama Power and Southern, Alabama Power relies minimally on the parent to maintain its financial conditions and maintains its own credit facilities and commercial paper program. Alabama Power's dividends to the parent in 2015 were $571 million, just over half of Georgia Power's 2015 dividend level of $1,034 million.

The affirmation of the rating and stable outlook of Georgia Power (A3) considers the continued strong state regulatory support for the Vogtle new nuclear project, including the potential for a prudence determination of project costs by the Georgia Public Service Commission earlier than we had originally anticipated; and a recent settlement with the EPC contractors resolving long-term legal and other disputes that had plagued the project, including the removal of construction contractor Chicago Bridge & Iron Co. N.V. (CB&I, unrated). Progress continues on the Vogtle project, with construction approximately 30% complete, although additional delays beyond the three years currently incorporated into the schedule are possible.

These positive attributes have offset some recent adverse developments with regard the Vogtle project, most notably the precipitous decline in the credit quality of Toshiba Corporation (B3 negative), the parent company of EPC contractor Westinghouse Electric Company LLC (unrated) and the guarantor of certain Westinghouse obligations under the EPC contract. While Westinghouse has provided nearly $1 billion of letters of credit to Georgia Power to support its obligations under the contract since Toshiba was downgraded below investment grade last year, we believe that a financially constrained Toshiba parent company could make additional costs and/or disputes related to the EPC contract more difficult to resolve.

While bonus depreciation will help support Georgia Power's financial metrics, which have declined as the Vogtle project has proceeded, the utility has also agreed to keep base rates flat for three years as part of a Georgia regulatory settlement for the AGL acquisition, which could offset these bonus depreciation benefits and pressure coverage metrics going forward. Georgia Power requested nearly $1 billion of rate relief three years ago and we had expected Georgia Power to file a rate case in 2016. Moody's notes that the parent's acquisition of AGL has had a more direct impact on Georgia Power than on any of Southern's other subsidiaries.

The affirmation of the rating and stable outlook of Gulf Power (A2) reflects the credit supportive regulatory environment in Florida, with a reasonable rate case settlement in place through June 2017, capital expenditures declining from recently high levels; offset by financial metrics that are slightly below our rating methodology guidelines for an A2 rating, with a three year average CFO pre-working capital to debt of 22.9%.

The affirmation of the rating and negative outlook of Mississippi Power (Baa3) reflects the regulatory risk in obtaining permanent cost recovery on the Kemper IGCC plant with two new commissioners recently elected to the Mississippi Public Service Commission (MPSC); last year's MPSC approval of interim rate relief on the plant; and the utility's weak liquidity and standalone financial condition with metrics expected to be below investment grade for at least one to two years. The outlook could be stabilized if the Kemper plant reaches commercial operation and a permanent cost recovery plan is approved by the MPSC and implemented by the utility.

The affirmation of the rating and stable outlook of Southern Power (Baa1) considers the company's high percentage of contracted capacity; limited fuel risk; historically strong cash flow coverage metrics that may moderate going forward as some tax benefits are extended out into future years, and a growing renewable energy business that is providing diversification to partially offset compressed margins at its legacy natural gas plants. Although there was a substantial increase in debt over the last year with debt increasing to $3.3 billion at 31 December 2015 from $1.8 billion at 31 December 2014, Moody's expects the company to continue to finance its aggressive growth plans with a balanced mix of debt issuance and equity contributions from the parent company.

The affirmation of the ratings of Southern Electric Generating Company (SEGCO A2), a single asset generating plant, reflects the stable outlooks on Alabama Power and Georgia Power, which each own 50%. SEGCO's single debt issue is rated A1 as it is fully guaranteed by Alabama Power.

The affirmation of the rating of Southern Company Funding Corporation (Prime-2), a commercial paper issuing vehicle, reflects the obligation and stable rating outlooks of the participating utilities: Alabama Power, Georgia Power and Gulf Power, to repay commercial paper issued by the funding company. Although Mississippi Power can also issue commercial paper under the program, it has not in recent years and has no plans to do so for the immediate future.

Rating Outlook

The stable rating outlook on Southern Company reflects the credit supportive regulatory environments in which its regulated utilities operate, the scale and diversity of its sources of cash flow, and Moody's expectation that it will not further increase parent company debt from current elevated levels.

Factors that Could Lead to an Upgrade

Southern's rating could be upgraded if there is a substantial reduction of parent company debt levels; the Vogtle and Kemper plants reach commercial operation without significant additional delays or cost increases; if one or more of its major utilities is upgraded (Alabama Power, Georgia Power, or AGL going forward); or if consolidated credit metrics return to previously strong levels, including CFO pre-working capital to debt in the 20% range.

Factors that Could Lead to a Downgrade

Southern's rating is well positioned at the Baa2 rating level but could be downgraded if there are material additional debt financed acquisitions; if there are additional delays or cost increases at the Vogtle nuclear project, and to a lesser degree the Kemper project; or if consolidated coverage metrics show a decline below the levels incorporated in our AGL acquisition projections, including cash flow from operations pre-working capital to debt below 15% for an extended period.

Downgrades:

..Issuer: Southern Company (The)

....Junior Subordinated Regular Bond/Debenture, Downgraded to Baa3 from Baa2

....Senior Unsecured Shelf, Downgraded to (P)Baa2 from (P)Baa1

....Senior Unsecured Bank Credit Facility, Downgraded to Baa2 from Baa1

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa2 from Baa1

Outlook Actions:

..Issuer: Alabama Power Capital Trust V

....Outlook, Remains Stable

..Issuer: Alabama Power Company

....Outlook, Remains Stable

..Issuer: Georgia Power Company

....Outlook, Remains Stable

..Issuer: Gulf Power Company

....Outlook, Remains Stable

..Issuer: Mississippi Power Company

.. .Outlook, Remains Negative

..Issuer: Southern Company (The)

....Outlook, Changed To Stable From Negative

..Issuer: Southern Company Funding Corporation

....Outlook, Remains Stable

. Issuer: Southern Elect Generating Co

....Outlook, Remains Stable

..Issuer: Southern Power Company

....Outlook, Remains Stable

Affirmations:

..Issuer: Alabama Power Capital Trust V

....Pref. Stock Preferred Stock, Affirmed A2

..Issuer: Alabama Power Company

.... Commercial Paper, Affirmed P-1

.... Issuer Rating, Affirmed A1

....Junior Subordinated Shelf, Affirmed (P)A2

....Preferred Shelf, Affirmed (P)A3

....Preference Shelf, Affirmed (P)A3

... Senior Unsecured Shelf, Affirmed (P)A1

....Preference Stock Preference Stock, Affirmed A3

....Pref. Stock Preferred Stock, Affirmed A3

....Senior Unsecured Bank Credit Facility, Affirmed A1

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Appling County Development Authority, GA

....Senior Unsecured Revenue Bonds, Affirmed A3

.. .Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Bartow County Development Authority, GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Burke County Development Authority, GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Columbia (Town of) AL, Industrial Dev. Board

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Coweta County Development Authority, GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Effingham County Industrial Dev. Auth., GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Escambia (County of) FL

....Senior Unsecured Revenue Bonds, Affirmed A2

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Eutaw (City of) AL, Industrial Dev. Board (Supported by Alabama Power Company)

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Eutaw (City of) AL, Industrial Dev. Board (Supported by Mississippi Power Company)

....Senior Unsecured Revenue Bonds, Affirmed Baa3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 3

..Issuer: Floyd County Development Authority GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Georgia Power Company

.... Issuer Rating, Affirmed A3

....Senior Secured Shelf, Affirmed (P)A3

....Junior Subordinated Shelf, Affirmed (P)Baa1

....Preferred Shelf, Affirmed (P)Baa2

....Preference Shelf, Affirmed (P)Baa2

....Preference Stock Preference StockAffirmed Baa2

....Pref. Stock Non-cumulative Preferred Stock, Affirmed Baa2

....Senior Unsecured Bank Credit Facility, Affirmed A3

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Gulf Power Company

.... Issuer Rating, Affirmed A2

....Subordinate Shelf, Affirmed (P)A3

....Junior Subordinated Shelf, Affirmed (P)A3

....Senior Unsecured Shelf, Affirmed (P)A2

....Preferred Shelf, Affirmed (P)Baa1

....Preference Shelf, Affirmed (P)Baa1

....Preference Stock Preference Stock, Affirmed Baa1

....Pref. Stock Preferred Stock, Affirmed Baa1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Harrison (County of) MS

....Senior Unsecured Revenue Bonds, Affirmed Baa3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 3

..Issuer: Heard County Development Authority, GA

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Jackson (County of) FL

....Senior Unsecured Revenue Bonds, Affirmed A2

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Mississippi Business Finance Corporation (Supported by Mississippi Power Company)

....Senior Unsecured Revenue Bonds, Affirmed Baa3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 3

..Issuer: Mississippi Business Finance Corporation (Supported by Gulf Power Company)

....Senior Unsecured Revenue Bonds, Affirmed A2

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Mississippi Power Company

.... Issuer Rating, Affirmed Baa3

....Pref. Stock Preferred Stock, Affirmed Ba2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa3

..Issuer: Mobile (City of) AL, I.D.B.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Monroe County Development Authority, GA (Supported by Georgia Power Company)

....Senior Unsecured Revenue Bonds, Affirmed A3

....Senior Unsecured Revenue Bonds, Affirmed VMIG 2

..Issuer: Monroe County Development Authority, GA (Supported by Gulf Power Company)

...Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Southern Company (The)

.... Commercial Paper, Affirmed P-2

..Issuer: Southern Company Funding Corporation

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Southern Elect Generating Co

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Southern Power Company

.... Issuer Rating, Affirmed Baa1

....Preference Shelf, Affirmed (P)Baa3

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Walker County Econ & Ind Dev Authority

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: West Jefferson (Town of) AL, Ind Devel. Bd.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Wilsonville (Town of) AL, I.D.B.

...Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

The principal methodology used in rating Southern Company (The), Georgia Power Company, Alabama Power Company, Mississippi Power Company, Gulf Power Company, Alabama Power Capital Trust V, Southern Elect Generating Co and Southern Company Funding Corporation was Regulated Electric and Gas Utilities published in December 2013. The principal methodology used in rating Southern Power Company was Unregulated Utilities and Unregulated Power Companies published in October 2014. Please see the Ratings Methodologies page on www.moodys.com for a copy of these methodologies.

The Southern Company is a utility holding company headquartered in Atlanta, Georgia and the parent company of utility subsidiaries Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Electric Generating Company, wholesale power company Southern Power Company, and commercial paper issuer Southern Company Funding Corporation.

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ALJ/EW2/jt2

Decision 16-03-007 March 17, 2016 **Date of Issuance 3/22/2016**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Central Valley Gas Storage, LLC (U915G), AGL Resources Inc. and The Southern Company for Expedited Ex Parte Authorization to Transfer Ownership of Central Valley Gas Storage, LLC to The Southern Company.	Application 15-11-011 (Filed November 9, 2015)

DECISION APPROVING CHANGE IN OWNERSHIP AND CONTROL OF CENTRAL VALLEY GAS STORAGE, LLC

Summary

This decision approves the application of Central Valley Gas Storage, LLC (Central Valley), AGL Resources Inc. (AGLR), and The Southern Company (Southern) (collectively, Joint Applicants) for a change in the ultimate ownership and control of Central Valley from AGLR to Southern. In addition to approving the proposed transfer, we conclude that the transactions underlying the transfer qualify for an exemption from the California Environmental Quality Act. Accordingly, additional environmental review is not required.

1. Procedural Background

In Decision (D.) 10-10-001, the Commission granted Central Valley Gas Storage, LLC (Central Valley), a certificate of public convenience and necessity (CPCN) for the construction and operation of an underground natural gas storage facility in Colusa County, including a 14.7-mile pipeline to connect with

Pacific Gas and Electric Company's (PG&E) natural gas transmission system. The CPCN was subject to certain conditions, including the requirement that Central Valley provide specified reports to Commission Staff and maintain $50 million of general liability insurance per occurrence and in the aggregate. The Commission also authorized Central Valley, a new public utility under Public Utilities Code Sections 216 and 222, to charge market-based rates. Finally, D.10-10-001 certified the Mitigated Negative Declaration for the facility and pipeline and authorized the issuance of a Notice of Determination for the Project pursuant to the California Environmental Quality Act (CEQA).

On January 25, 2011, Central Valley, Nicor Inc. (Nicor), and AGL Resources Inc. (AGLR) filed Application (A.) 11-01-021. The application did not seek to transfer Central Valley's CPCN or modify the conditions imposed on Central Valley in D.10-10-001. Rather, it sought authorization for an indirect change in control of Central Valley as the result of a proposed merger between Nicor and AGLR. The Commission granted the application by D.11-05-030 and concluded that the transactions underlying the transfer qualified for an exemption from CEQA.

On August 23, 2015, AGLR and The Southern Company (Southern) executed a Merger Agreement which provides AGLR will become a wholly owned subsidiary of Southern.

On November 9, 2015, Joint Applicants filed the current application. Like Application (A.) 11-01-021, it does not seek to transfer Central Valley's CPCN or modify the conditions imposed on Central Valley in D.10-10-001. Rather, it seeks authorization for an indirect change in control of Central Valley as the result of a proposed merger between AGLR and Southern.

Wild Goose Storage LLC (Wild Goose) filed the only response to the application. Wild Goose is not opposed to the application and stated it only intends to actively participate in the proceeding if it raises issues of broad applicability to Wild Goose and the other California independent storage providers concerning the transfer of control pursuant to Public Utilities Code Section 854(a).

A duly noticed prehearing conference was held on January 14, 2016 and a scoping ruling was issued January 26, 2016. As agreed by the parties, no further briefing is needed.

2. Application 15-11-011

The Joint Applicants filed A.15-11-011 on November 9, 2015. Notice of the Application was first published in the Commission's Daily Calendar on November 19, 2015. The Application seeks authorization for an indirect change in control of Central Valley as the result of a proposed merger between AGLR and Southern.

2.1. The Applicants

Central Valley is a Delaware limited liability company and is duly registered to transact business in California. Its principal place of business is Lisle, Illinois.

Central Valley owns and operates an 11 billion cubic foot underground natural gas storage field within the Princeton Gas Field and a natural gas pipeline extending approximately 14.7 miles from the storage field to an interconnection with the metering station and PG&E's Line 400/401 gas transmission pipeline. Central Valley commenced commercial operation in March 2012.

AGLR is a Georgia corporation headquartered in Atlanta, Georgia. AGLR's principal business is the distribution of natural gas through public utility operating companies in seven states. Through its non-utility subsidiaries, AGLR also is involved in several other businesses, including: retail natural gas marketing to end-use customers; natural gas asset management and related logistics activities for certain of its utilities and nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets.

Southern is an Atlanta-based public utility holding company currently providing electric utility service through four state-regulated operating companies in Alabama, Florida, Georgia and Mississippi.

2.2. The Proposed Transaction

Joint Applicants seek Commission authorization for a change in the ultimate ownership and control of Central Valley from AGLR to Southern as a result of an agreement and plan of merger between Southern, AMS Corp., and AGLR (the Merger Agreement).

Since receiving its CPCN, Central Valley has been a subsidiary of Nicor Energy Venture Company. At the time the CPCN was granted, Nicor Energy Venture Company was a wholly-owned subsidiary of Nicor, Inc. Following the merger approved by D. 11-05-030, Nicor Energy Venture Company became a subsidiary of Ottawa Acquisition LLC; which in turn is a subsidiary of AGLR.

Under the current Merger Agreement, Southern will acquire AGLR by purchasing all of its common stock. AMS Corp., a wholly-owned subsidiary of Southern, will be merged into AGLR, with AGLR the surviving corporation. Upon completion of the merger, although AGLR will continue to exist as a distinct corporate entity, it will no longer be a publicly traded company. Instead,